MPSC Case No. U-20276
UPPCO Exhibit List

Part	UPPCO Exhibit No.	Schedule	Title	Witness
I	A-1	A1	Historical Revenue Deficiency (Sufficiency)	Nicholas E. Kates
I	A-1	A2	Historical Financial Metrics	Nicholas E. Kates
I	A-2	B1	Historical Rate Base	Nicholas E. Kates
I	A-2	B2	Historical Utility Plant	Nicholas E. Kates
I	A-2	B3	Historical Depreciation Reserve and Other Deductions	Nicholas E. Kates
I	A-2	B4	Historical Working Capital	Nicholas E. Kates
I	A-2	C1	Historical Adjusted Net Operating Income	Nicholas E. Kates
I	A-3	C2	Historical Revenue Conversion Factor	Nicholas E. Kates
I	A-3	C3	Historical Operating Revenue	Nicholas E. Kates
I	A-3	C4	Historical Fuel and Purchased Power/Cost of Gas Sold	Nicholas E. Kates
I	A-3	C5	Historical Operation and Maintenance Expenses	Nicholas E. Kates
I	A-3	C6	Historical Depreciation and Amortization Expenses	Nicholas E. Kates
I	A-3	C7	Historical General Taxes	Nicholas E. Kates
I	A-3	C8	Historical Federal Income Taxes	Nicholas E. Kates
I	A-3	C9	Historical State Income Taxes	Nicholas E. Kates
I	A-3	C10	Historical Other (or Local) Taxes	Nicholas E. Kates
I	A-3	C11	Historical Allowance for Funds Used During Construction	Nicholas E. Kates
I	A-4	D1	Historical Rate of Return Summary	Nicholas E. Kates
I	A-4	D2	Historical Cost of Long-Term Debt	Nicholas E. Kates
I	A-4	D3	Historical Cost of Short-Term Debt	Nicholas E. Kates
I	A-4	D4	Historical Cost of Preferred Stock	Nicholas E. Kates
I	A-4	D5	Historical Cost of Common Shareholders' Equity	Nicholas E. Kates
I	A-5	E1	Historical Sales, Load and Customer Data	Eric W. Stocking
I	A-11	A1	Projected Revenue Deficiency (Sufficiency)	Nicholas E. Kates
I	A-11	A2	Projected Financial Metrics	Nicholas E. Kates
I	A-12	B1	Projected Rate Base	Nicholas E. Kates
I	A-12	B2	Projected Utility Plant	Nicholas E. Kates
I	A-12	B3	Projected Accumulated Provision for Depreciation	Nicholas E. Kates
I	A-12	B4	Projected Working Capital	Nicholas E. Kates
I	A-12	B5	Projected Capital Expenditure Summary and Supporting Exhibits	Nicholas E. Kates
I	A-12	B5.1	Projected Power Generation CAPEX Summary	Nicholas E. Kates
I	A-12	B5.4	Projected Distribution & Substation CAPEX by Business Driver	Nicholas E. Kates
I	A-12	B5.5	Projected Advanced Metering Infrastructure (AMI) CAPEX	Nicholas E. Kates
I	A-12	B5.6	Projected Total Corporate | General Plant CAPEX	Nicholas E. Kates
I	A-13	C1	Projected Net Operating Income	Nicholas E. Kates
I	A-13	C2	Projected Revenue Conversion Factor	Nicholas E. Kates
I	A-13	C3	Projected Sales Revenue	Nicholas E. Kates
I	A-13	C4	Projected Fuel and Purchased Power/Cost of Gas Sold	Nicholas E. Kates
I	A-13	C5	Projected Operation and Maintenance Expenses	Nicholas E. Kates
I	A-13	C6	Projected Depreciation and Amortization Expenses	Nicholas E. Kates
I	A-13	C7	Projected General Taxes	Nicholas E. Kates
I	A-13	C8	Projected Federal Income Taxes	Nicholas E. Kates
I	A-13	C9	Projected State Income Taxes	Nicholas E. Kates
I	A-13	C10	Projected Other (or Local) Taxes	Nicholas E. Kates
I	A-13	C11	Projected Allowance for Funds Used During Construction	Nicholas E. Kates
I	A-14	D1	Projected Rate of Return Summary	Nicholas E. Kates
I	A-14	D2	Projected Cost of Long-Term Debt	Nicholas E. Kates
I	A-14	D3	Projected Cost of Short-Term Debt	Nicholas E. Kates
I	A-14	D4	Projected Cost of Preferred Stock	Nicholas E. Kates
I	A-14	D5	Projected Cost of Common Shareholders' Equity	Nicholas E. Kates
I	A-15	E1.1	Projected Sales, Load and Customer Data	Eric W. Stocking
I	A-15	E1.2	Projected	Eric W. Stocking
I	A-15	E1.3	Projected	Eric W. Stocking
I	A-15	E2.1	Projected	Eric W. Stocking
I	A-15	E2.2	Projected	Eric W. Stocking

Part	UPPCO Exhibit No.	Schedule	Title	Witness
I	A-16	F1	Projected Cost of Service Allocation Study	Gradon R. Haehnel
I	A-16	F2	Summary of Present and Proposed Revenues	Eric W. Stocking
I	A-16	F3	Detail of Present and Proposed Revenues	Eric W. Stocking
I	A-16	F4	Comparison of Present and Proposed Monthly Bills	Eric W. Stocking
I	A-16	F5	Proposed Tariff Sheets	Eric W. Stocking
I	A-17		2019 Financial Summary	Nicholas E. Kates
I	A-18		2019 Forecast Adjustments	Nicholas E. Kates
I	A-19		FERC 926 Summary	Nicholas E. Kates
I	A-20		AFUDC Calculation	Nicholas E. Kates
I	A-21		2019 LIBOR	Nicholas E. Kates
I	A-22		Q2-2018 CPI	Nicholas E. Kates
I	A-23		Salary & Wage Adjustment	Nicholas E. Kates
I	A-24		Uncollectible Accounts (Bad Debt Expense)	Nicholas E. Kates
I	A-25		Willis Towers & Watson Report - Pension & OPEB	Nicholas E. Kates
I	A-26		UPPCO Information Technology (IT) CAPEX	Nicholas E. Kates
I	A-27		UPPCO Capital Expenditures (CAPEX) by Business Line	Keith E. Moyle
I	A-28		UPPCO Facility CAPEX	Keith E. Moyle
I	A-29		UPPCO Substation CAPEX	Keith E. Moyle
I	A-30		UPPCO Generation CAPEX	Keith E. Moyle
I	A-31		UPPCO Distribution Reliability CAPEX	Keith E. Moyle
I	A-32		2013-2017 Reliability Indices (as Filed)	Keith E. Moyle
I	A-33		2013-2017 Reliability Indices (as Revised)	Keith E. Moyle
I	A-34		Major Event Days	Keith E. Moyle
I	A-35		Weather Outages by Cause	Keith E. Moyle
I	A-36		2015-2017 Pole Inspections	Keith E. Moyle
I	A-37		2015-2017 Undergound Inspections	Keith E. Moyle
I	A-38		2018-2020 System Hardening and Reliability Projects	Keith E. Moyle
I	A-39		6 Year Distribution Line Clearance Program	Keith E. Moyle
I	A-40		Revenue Credit Update	Gradon R. Haehnel
I	A-41		2019 Escanaba Forecast Adjustments	Gradon R. Haehnel
I	A-42		PSCR Base	Eric W. Stocking
I	A-43		MPSC Staff Report U-17000	Jason Brynick
I	A-44		EIA Smart Meter Report	Jason Brynick
I	A-45		Itron OpenWay Riva Security	Jason Brynick
I	A-46		Non-Standard Meter Provision Cost Calculation	Jason Brynick
I	A-47		AMI Business Process Requirements Summary	Jason Brynick
I	A-48		AMI Project Cost Analysis	Jason Brynick
I	A-49		AMI Project Benefits for OWOC	Jason Brynick
I	A-50		AMI Project Benefits for MDM	Jason Brynick
I	A-51		AMI Financial Analysis	Jason Brynick
I	A-52		AMI Revenue Requirement	Jason Brynick
I	A-53		AMI Project Schedule	Jason Brynick
I	A-54		Non-Standard Meter Definition	Jason Brynick
I	A-55		Non-Standard Meter Provision	Jason Brynick
I	A-57		ROE Analyses Summary of Results	Adrien M. McKenzie
I	A-58		Regulatory Mechanisms	Adrien M. McKenzie
I	A-59		Capital Structure	Adrien M. McKenzie
I	A-60		DCF Model	Adrien M. McKenzie
I	A-61		DCF Model BR+SV Growth Rate	Adrien M. McKenzie
I	A-62		CAPM	Adrien M. McKenzie
I	A-63		Empirical CAPM	Adrien M. McKenzie
I	A-64		Electric Utility Risk Premium	Adrien M. McKenzie
I	A-65		Expected Earnings Approach	Adrien M. McKenzie
I	A-66		DCF Model - Non-Utility Group	Adrien M. McKenzie
II			Annual Reports to the MPSC P-521 (electric) P-522 (gas) for the most recent 2 years	
II	n/a	n/a	Annual Report to the SEC Form 10-K	
II	n/a	n/a	Quarterly Report to Shareholders (most recent 4 quarters)	

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UPPCO Exhibit List

Part	UPPCO Exhibit No.	Schedule	Title	Witness
II	n/a	n/a	Bond and other financial prospectuses for issuances during the past 2 years	
III	n/a	n/a	see "Pivot_Master"	
	B5 schedules from Juris			

Upper Peninsula Power Company

Upper Peninsula Power Company Retirement Plan

Actuarial Valuation Report Employer Contributions for Plan Year Beginning January 1, 2017

September 2017

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Purposes of valuation

Upper Peninsula Power Company (the Company) retained Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC ("Willis Towers Watson"), to perform an actuarial valuation of the Upper Peninsula Power Company Retirement Plan for the purpose of determining the following:

1. The minimum required contribution in accordance with ERISA and the Internal Revenue Code (IRC) for the plan year beginning January 1, 2017.

2. The estimated maximum tax-deductible contribution for the tax year in which the 2017 plan year ends in accordance with ERISA as allowed by the IRC. The maximum tax-deductible contribution should be finalized in consultation with the Company's tax advisor.

3. Plan accounting information in accordance with FASB Accounting Standards Codification Topic 960 (ASC 960).

4. An assessment of ERISA §4010 reporting requirements for the plan for 2017.

5. Determination of the Funding Target Attainment Percentage (FTAP) under IRC §430(d)(2), as reported in the Annual Funding Notice required under ERISA §101(f).

6. As requested by Upper Peninsula Power Company, a "specific certification" of the Adjusted Funding Target Attainment Percentage (AFTAP) for the Upper Peninsula Power Company Retirement Plan under IRC §436 for the plan year beginning January 1, 2017. Please see Appendix C for additional information. Note that the AFTAP certification included herein may be superseded by a subsequent AFTAP certification for the Upper Peninsula Power Company Retirement Plan for the plan year beginning January 1, 2017.

Limitations

This valuation has been conducted for the purposes described above and may not be suitable for use for any other purpose. In particular, please note the following:

1. This report does not determine the plan's liquidity shortfall requirements (if any) under IRC §430(j)(4). If applicable, we will determine such requirements separately as requested by the Company.

2. This report does not determine liabilities on a plan termination basis, for which a separate extensive analysis would be required. No funded status measure included in this report is intended to assess, and none may be appropriate for assessing, the sufficiency of plan assets to cover the estimated cost of settling the plan's benefit obligations, as all such measures differ in some way from plan termination obligations. For example, measures shown in this report may reflect smoothed assets or interest rates, rather than current values, in accordance with funding rules. In addition, funded status measures shown in this report do not reflect the current costs of

settling the plan obligations by offering immediate lump sum payments to participants and/or purchasing annuity contracts for the remaining participants (e.g., insurer profit, insurer pricing of contingent benefits and/or provision for anti-selection in the choice of a lump sum vs. an annuity).

3. The cost method for the minimum required contribution is established under IRC §430 and may not in all circumstances produce adequate assets to pay benefits under all optional forms of payment available under the plan when benefit payments are due.

4. The comparison of the plan's funding target to its actuarial value of assets (the funding shortfall (surplus) shown in Section 1) is used in determining required contributions for the coming year, and a contribution made on the valuation date equal to the shortfall would be considered to "fully fund" the plan for benefits accrued as of the valuation date under the funding rules, and thus is useful for assessing the need for and amount of future contributions. However, the funding shortfall (surplus) cannot be relied upon to determine either the need for or the amount of future contributions. The funding shortfall (surplus) is based on the interest rates elected to be used for funding purposes, which may be smoothed rates not reflecting current market conditions and will in any event change over time. It is also based on the actuarial value of assets, so if an asset smoothing method is used, it would be different than if based on market value of assets. In addition, asset gains and losses, demographic experience different from assumed, and future benefit accruals (if any) will all affect the need for and amount of future contributions.

5. There may be certain events that occurred since the valuation date that are not reflected in this valuation. See Subsequent Events (under the "Basis for valuation" portion of Section 1 below) for more information.

6. This valuation reflects our understanding of the relevant provisions of the Pension Protection Act of 2006 (PPA); the Worker, Retiree and Employer Recovery Act of 2008 (WRERA); the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 (PRA); the Moving Ahead for Progress in the 21^{st} Century Act (MAP-21); the Highway and Transportation Funding Act of 2014 (HATFA); and the Bipartisan Budget Act of 2015. The IRS has yet to issue final guidance with respect to certain aspects of these laws. It is possible that future guidance may conflict with our understanding of these laws based on currently available guidance and could therefore affect results shown in this report.

Section 1: Summary of results

Minimum required contribution and funding policy

All monetary amounts shown in US Dollars

Plan Year Beginning	01/01/2017	01/01/2016
Minimum Required Contribution (MRC)		
Prior to application of funding balances	0	0
Net of available funding balances	0	0

The plan sponsor's funding policy generally has been to make contributions sufficient to maintain an 80% funded pension, but not less than the minimum required contribution nor more than the maximum deductible contribution for the plan year. We understand that the sponsor may deviate from this policy based on cash, tax or other considerations.

The minimum required contribution includes a contribution to cover the benefits expected to accrue in the coming year (if any) plus expenses expected to be paid from the trust in the coming year (if any) (target normal cost), as well as a 7-year amortization (with a somewhat longer amortization period for shortfall amortization bases established in any year for which funding relief was elected) of any funding shortfall (amortization installments). See Section 2.4 for a break-down of the minimum required contribution into target normal cost and amortization installments. Thus, assuming that all actuarial assumptions are realized and do not change and the plan sponsor contributes the minimum required contribution each year (target normal cost plus amortization installments), the plan would generally be expected to be fully funded in 7 years, and the minimum required contribution would be expected to drop to target normal cost. During the 7 year period, there will be some variability in minimum required contributions due to amortization installments from prior years dropping out as the 7-year amortization period ends (and for deferred asset gains or losses becoming reflected in assets if an asset smoothing method is used for the actuarial value of assets). In reality, gains and losses will occur, and the plan sponsor may fail to contribute the minimum required contribution (or may contribute more than the minimum required contribution in accordance with the funding policy described above), which may cause the plan to take more or less than 7 years to become fully funded. Note that being fully funded under the funding rules is not the same as being fully funded on a plan termination basis, as different assumptions apply (e.g., the cost of annuity contracts or lump sums to participants) on plan termination.

Target normal cost for individual participants accruing benefits will grow from year to year as participants age (and as their salaries increase, if benefit accruals are pay related), but the changes in total target normal cost will depend on the numbers of participants earning benefits and their ages. Because the plan is closed, target normal cost may grow for several years as participants age but then begin to decline as the number of participants declines. Of course, changes in discount rates and other assumptions in future years will also influence the pattern of future required contributions.

The minimum required contribution for the 2017 plan year must be satisfied by September 15, 2018. This requirement may be satisfied through contributions and/or an election to apply the available funding balances. No quarterly installments are required. The minimum required contribution is determined assuming it is paid as of the valuation date for the plan year. Contributions made on a date other than the valuation date must be adjusted for interest at the plan's effective interest rate.

Summary of valuation results

All monetary amounts shown in US Dollars

Plan Year Beginning	01/01/2017	01/01/2016
Funding		
Market value of assets with discounted receivable contributions	109,087,777	111,029,075
Actuarial value of assets	111,000,755	114,645,518
Funding balances	7,366,124	6,996,698
Funding target	84,889,396	84,317,613
Target normal cost	1,150,399	1,096,917
Funding shortfall (surplus) (FS)	(18,745,235)	(23,331,207)
Funding target attainment percentage (FTAP)	122.08%	127.67%
Minimum required contribution		
Prior to application of funding balances	0	0
Net of available funding balances	0	0
Effective interest rate	5.82%	6.01%
Plan Accounting (ASC 960)		
Present value of accumulated benefits	94,874,953	96,344,812
Market value of assets with receivable contributions	109,087,777	111,029,075
Plan accounting discount rate	5.15%	5.15%
Participants as of Census Date	**01/01/2017**	**01/01/2016**
Active employees	82	88
Participants with deferred benefits	71	76
Participants receiving benefits	524	524
Total	677	688

Change in minimum funding requirement and funding shortfall (surplus)

The minimum funding requirement is unchanged from $0 for the 2016 plan year to $0 for the 2017 plan year, and the funding surplus decreased from $23,331,207 on January 1, 2016 to $18,753,310 on January 1, 2017.

Significant reasons for these changes include the following:

- The return on the actuarial value of assets since the prior valuation was less than expected, which reduced the funding surplus.
- The plan's effective interest rate declined 19 basis points compared to the prior year, which reduced the funding surplus.

Funding ratios

The Pension Protection Act of 2006 (PPA) defines several Funding Ratios. All of these ratios are based on a ratio of plan assets to plan liabilities, but the assets and liabilities are defined differently for different purposes. Depending on the purpose, the assets may be market value or, if different, a smoothed actuarial value of assets, and may be reduced by the prefunding balance or all funding balances. The liabilities may be based on the funding target, funding target disregarding at-risk assumptions, or the funding target calculated using at-risk assumptions (see the At-Risk status section below), and may or may not reflect stabilized interest rates.

Following are the key funding ratios and their implications for the 2017 or 2018 plan years. See Appendix D for details on how each ratio is calculated.

January 1, 2016 Funding ratios

	Ratio Test Implications	Threshold	Ratio Value
1	Funding balances can be used to satisfy the 2017 Minimum Required Contribution (MRC) if threshold met	80%	127.67%
2	Quarterly contribution exemption applies in 2017 if threshold met	100%	127.67%
3	Plan is not at-risk for 2017 if the threshold for either the Prong 1 or Prong 2 test is met		
	- Prong 1 Test	80%	127.67%
	- Prong 2 Test	70%	N/A

January 1, 2017 Funding ratios

	Ratio Test Implications	Threshold	Ratio Value
1	Funding balances can be used to satisfy the 2018 MRC if threshold met	80%	122.08%
2	Quarterly contribution exemption applies in 2018 if threshold met	100%	122.08%
3	Plan is not at-risk for 2018 if the threshold for either the Prong 1 or Prong 2 test is met		
	- Prong 1 Test	80%	122.08%
	- Prong 2 Test	70%	N/A
4	PBGC 4010 filing may be required in 2018 if threshold is not met by every plan in the controlled group	80%	101.85%
5	Plan is exempt from creating a new Shortfall Amortization Base (SAB) for 2017 when prefunding balance is applied to the 2017 MRC if threshold met	100%	122.08%
6	Plan is exempt from creating a new SAB for 2017 when prefunding balance is not applied to the 2017 MRC if threshold met	100%	130.75%
7	Previously established SABs are eliminated for 2017 if threshold met	100%	122.08%

Benefit limitations

The Adjusted Funding Target Attainment Percentage (AFTAP) for the plan year beginning January 1, 2017 is 130.75%. This AFTAP may be changed by subsequent events.

Under the PPA, a plan may become subject to various benefit limitations if its AFTAP falls below certain thresholds.

If the AFTAP is below 60% (100% if the plan sponsor is in bankruptcy, calculated ignoring stabilized interest rates), plans are prohibited from paying lump sums or other accelerated forms of distribution. If the AFTAP is at least 60% but less than 80%, the amounts that can be paid are limited. In addition, lump sums to the 25 highest paid employees may be restricted if a plan's AFTAP is below 110%. These limitations do not apply to mandatory lump sum cash-outs of $5,000 or less. In addition, plans that were completely frozen before September 2005 are exempt from the restrictions on lump sums and other accelerated forms of distribution.

If the AFTAP is below 60%, benefit accruals must cease, amendments to improve benefits cannot take effect, and plant shutdown benefits and other Unpredictable Contingent Event Benefits (UCEBs) cannot be paid without being fully paid for. In addition, if the AFTAP would be below 80% reflecting a proposed amendment, the plan amendment cannot take effect unless actions are taken to increase plan assets.

To avoid these benefit limitations, a plan sponsor may take a variety of steps, including reducing the funding balances, contributing additional amounts to the plan for the prior plan year, contributing special "designated IRC §436 contributions" for the current plan year, or providing security outside the plan. Not all of these approaches are available for all of the restrictions discussed above. For example, restrictions on accelerated distributions cannot be avoided by making designated IRC §436 contributions.

As requested by Upper Peninsula Power Company in your letter dated August 28, 2017, this report is intended to constitute a "specific certification" of the AFTAP, effective as of September 14, 2017, for the plan year beginning January 1, 2017 for the purpose of determining benefit restrictions under IRC §436 for the Upper Peninsula Power Company Retirement Plan. This AFTAP certification is based on the data, methods, assumptions, plan provisions, annuity purchase information, and other information provided in this report. Please see the Appendices for additional information. Note that the AFTAP certification provided herein may be superseded by a subsequent AFTAP certification for the plan year beginning January 1, 2017. Please see Appendix C for a discussion of the implications of this certified AFTAP.

PBGC reporting requirements

Certain financial and actuarial information (i.e., a “4010 filing”) must be provided to the PBGC if the PBGC Funding Target Attainment Percentage (PBGC FTAP) is less than 80% for any plan in the contributing sponsor’s controlled group. However, this reporting requirement may be waived for controlled groups with no more than $15 million in aggregate funding shortfall (PBGC 4010 FS), or with fewer than 500 participants in all defined benefit plans. Note that interest rate stabilization does not apply for purposes of determining the PBGC FTAP or the PBGC 4010 FS.

The 2017 FTAP is 101.85%. However, the Company will need to determine whether other plans within its controlled group have PBGC FTAPs below 80% to determine whether a 4010 filing may be required for 2017. A filing may also be required if there are outstanding funding waivers or missed contributions within the controlled group.

At-Risk status for determining minimum required contributions

The plan is not in at-risk status, as defined in the PPA, for the 2017 plan year, because the plan's FTAP for the 2016 plan year was at least 80%, and/or the plan’s FTAP measured using “at-risk assumptions” was at least 70%.

The plan will not be in at-risk status, as defined in the PPA, for the 2018 plan year, because the plan’s FTAP for the 2017 plan year is at least 80%, and/or the plan’s FTAP measured using “at-risk assumptions” is at least 70%.

When a plan is in at-risk status as defined in the PPA*:*

- The plan is subject to potentially higher minimum contribution requirements. The funding target and target normal cost for purposes of determining the minimum required contribution must be measured reflecting certain mandated assumptions (“at-risk assumptions”). Specifically, participants eligible to retire within the next 11 years must be assumed to retire immediately when first eligible (but not before the end of the current year, except in accordance with the regular valuation assumptions), and all participants must be assumed to elect the most valuable form of payment available when they begin receiving benefits. In addition, plans that have been at-risk in past years may also be required to increase the funding target and target normal cost for prescribed assumed expenses. The net effect of these assumptions and expense adjustments in most cases is to increase required contributions and PBGC variable premiums.
- The plan sponsor must indicate in the annual funding notice for the plan that the plan is at-risk and disclose additional at-risk funding targets.
- Immediate taxation of non-qualified pension or deferred compensation for certain employees may occur if the plan sponsor is a public company. This may result when non-qualified pension or deferred compensation for such employees is funded during a period when a plan sponsored by the plan sponsor or another member of the plan sponsor's controlled group is in at-risk status.

Basis for valuation

Appendix A summarizes the assumptions and methods used in the valuation. Appendix B summarizes the principal provisions of the plan being valued, including a summary of any changes since the prior valuation. Unless otherwise described below under Subsequent Events, assumptions were selected based on information known as of the measurement date.

Subsequent Events

The plan was amended in 2017 to add a minimum interest crediting rate of 3.05%. This amendment was reflected in determining the plan's AFTAP.

Actuarial certification

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. However, please note the information discussed below regarding this valuation.

Reliances

In preparing the results presented in this report, we have relied upon information regarding plan provisions, participants, assets and sponsor elections provided by Upper Peninsula Power Company and other persons or organizations designated by Upper Peninsula Power Company. See the Data Sources section of Appendix A for further details. In addition, the results in this report are dependent on contributions reported for the prior plan year and maintenance of funding balance elections after the valuation date.

We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

We have relied on all the information provided as complete and accurate. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or information regarding contributions or funding balance elections provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by Upper Peninsula Power Company, may produce materially different results that could require that a revised report be issued.

Assumptions and methods under ERISA and the Internal Revenue Code for funding purposes

The plan sponsor selected, as prescribed by regulation, key assumptions and funding methods (including asset valuation method and choice among prescribed interest rates) employed in the development of the contribution amounts and communicated them to us in the letter dated September 13, 2017.

To the extent not prescribed by ERISA, the Internal Revenue Code and regulatory guidance from the Treasury and the IRS, or selected by the sponsor, the actuarial assumptions and methods employed in the development of the contribution amounts have been selected by Willis Towers Watson, with the concurrence of the plan sponsor. It is beyond the scope of this actuarial valuation to analyze the reasonableness and appropriateness of prescribed methods and assumptions, or to analyze other sponsor elections from among the alternatives available for prescribed methods and assumptions.

Other than prescribed assumptions, ERISA and the Internal Revenue Code require the use of assumptions each of which is “reasonable (taking into account the experience of the plan and reasonable expectations), and which, in combination, offer the actuary’s best estimate of anticipated experience under the plan.” The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated or selected by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

A summary of the assumptions and methods used is provided in Appendix A. Note that any subsequent changes in methods or assumptions for the 2017 plan year will change the results shown in this report and could result in plan qualification issues under IRC §436 if the application of benefit restrictions is affected by the change.

Nature of actuarial calculations

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. Any rounding (or lack thereof) used for displaying numbers in this report is not intended to imply a degree of precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs or contribution requirements reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions; increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period or additional contribution requirements based on the plan’s funded status); and changes in plan provisions or applicable law. It is beyond the scope of this valuation to analyze the potential range of future pension contributions, but we can do so upon request.

See Basis for Valuation in Section 1 above for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

Limitations on use

This report is provided subject to the terms set out herein and in our engagement letter dated April 8, 2014 and any accompanying or referenced terms and conditions.

The information contained in this report was prepared for the internal use of Upper Peninsula Power Company and its auditors and any organization that provides benefit administration services for the plan in connection with our actuarial valuation of the pension plan as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. Upper Peninsula Power Company may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require Upper Peninsula Power Company to provide them this report, in which case Upper Peninsula Power Company will use best efforts to notify Willis Towers Watson in advance of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

Professional qualifications

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between Upper Peninsula Power Company and our employer, Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC.

Georgia Louridas, FSA, EA
Senior Consulting Actuary
17-8034
September 14, 2017

Steven James, FSA, EA
Senior Consulting Actuary
17-06406
September 14, 2017

Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC

September 2017

Section 2: Actuarial exhibits

2.1 Summary of liabilities for minimum funding purposes

All monetary amounts shown in US Dollars

Plan Year Beginning	01/01/2017	01/01/2016
A Funding Target (Disregarding At-risk Assumptions)		
1 Funding target		
a Active employees – non-vested benefits[1]	1,664,439	1,707,096
b Active employees – vested benefits[1]	11,637,446	11,277,334
c Participants with deferred benefits	2,758,962	2,828,372
d Participants receiving benefits	68,828,549	68,504,811
e Total funding target	84,889,396	84,317,613
2 Target normal cost	1,150,399	1,096,917
B Funding Target (At-risk Assumptions)		
1 Funding target	N/A	N/A
2 Target normal cost	N/A	N/A
C Funding Target		
1 Number of consecutive years at-risk	0	0
2 Funding target		
a Active employees – non-vested benefits[1]	1,664,439	1,707,096
b Active employees – vested benefits[1]	11,637,446	11,277,334
c Participants with deferred benefits	2,758,962	2,828,372
d Participants receiving benefits	68,828,549	68,504,811
e Total funding target	84,889,396	84,317,613
3 Target normal cost	1,150,399	1,096,917

[1] See section 2.8 for definition of vested benefits.

2.2 Change in plan assets during plan year

All monetary amounts shown in US Dollars

Plan Year Beginning			January 1, 2016
A	**Reconciliation of Market Value of Assets**		
	1	Market value of assets at January 1, 2016 (including discounted contributions receivable)	111,029,075
	2	Discounted contributions receivable at January 1, 2016	0
	3	Market value of assets at January 1, 2016 (excluding contributions receivable)	111,029,075
	4	Employer contributions	
		a For prior plan year	0
		b For current plan year	0
		c IRC §436 contributions for current plan year	0
		d Total	0
	5	Employee contributions	0
	6	Benefit payments	(7,012,311)
	7	Administrative expenses paid by plan	(590,742)
	8	Transfers from/(to) other plans	0
	9	Investment return	5,661,755
	10	Market value of assets at January 1, 2017 (excluding contributions receivable)	109,087,777
	11	Discounted contributions receivable at January 1, 2017	0
	12	Market value of assets at January 1, 2017 (including discounted contributions receivable)	109,087,777
B	**Rate of Return on Invested Assets (i.e., for crediting unused funding balances)**		
	1	Weighted invested assets	107,227,548
	2	Rate of return	5.28%

2.3 Development of actuarial value of assets

All monetary amounts shown in US Dollars

Plan Year Beginning					January 1, 2017
A	**Preliminary Actuarial Value of Assets before Corridor as of January 1, 2017**				
	1 Market value of assets as of January 1, 2017				109,087,777
	2 Discounted receivable employer contributions				0
	3 Deferred investment gains/(losses) for prior periods				
		Plan Year Beginning	**Gain/(Loss)**	**Percent Deferred**	**Deferred Amount**
		a 01/01/2016	137,079	66.667%	91,386
		b 01/01/2015	(6,013,091)	33.333%	(2,004,364)
		c Total			(1,912,978)
	4 Preliminary actuarial value of assets before application of corridor				111,000,755
B	**Lower Bound of Corridor**				98,178,999
C	**Upper Bound of Corridor**				119,996,555
D	**Actuarial Value of Assets after Corridor as of January 1, 2017**				111,000,755
E	**Rate of Return**				3.57%

2.4 Calculation of minimum required contribution

All monetary amounts shown in US Dollars

Reconciliation of Funding Balances as of January 1, 2017	Funding Standard Carryover Balance	Prefunding Balance	Total
A Determination of Funding Balances			
1 Funding balance as of January 1, 2016	0	6,996,698	6,996,698
2 Amount used to offset prior year minimum required contribution[1]	0	0	0
3 Adjustment for investment experience	0	369,426	369,426
4 Amount of additional prefunding balance created by election	N/A	0	0
5 Amount of funding balance reduction for current year by election or deemed election	0	0	0
6 Funding balance as of January 1, 2017	0	7,366,124	7,366,124

Plan Year Beginning	January 1, 2017
B Calculation of Minimum Required Contribution	
1 Target normal cost	1,150,399
2 Funding surplus	(18,745,235)
3 Net shortfall amortization installment (see section 2.5)	0
4 Waiver amortization installment	0
5 Minimum required contribution	0
6 Funding balance available	7,366,124
7 Remaining cash requirement (assuming sponsor elects full use of the available funding balances)	0

The minimum required contribution is determined as of the plan's valuation date. Any payment made on a date other than the valuation date must be adjusted for interest using the plan's effective interest rate of 5.82%.

Additional details regarding the calculation of the minimum required contribution may be obtained from the Form 5500 Schedule SB forms and attachments.

[1] Net of revoked excess application of funding balance, if any.

2.5 Calculation of PBGC variable rate premium

All monetary amounts shown in US Dollars

Premium Payment Year	2017
A Assumptions and Methods Used to Determine Premium Funding Target	
1 Premium funding target method	Standard
2 Premium funding target method election date	N/A
3 UVB valuation date	January 1, 2017
4 Discount rates	
a First segment rate	2.04%
b Second segment rate	4.03%
c Third segment rate	4.82%
B Premium Funding Target	
1 Attributable to active participants	14,521,679
2 Attributable to terminated vested participants	3,633,848
3 Attributable to retirees	79,379,817
4 Total premium funding target[1]	97,535,344
C Market Value of Assets	109,087,777
D Unfunded Vested Benefits	0
E Uncapped Variable Rate Premium[2]	0
F Maximum VRP[3]	350,009
G Variable Rate Premium	0

[1] Reflects at-risk status, if applicable.
[2] Using variable rate premium of $34 per $1,000 of unfunded vested benefits.
[3] Using maximum per-participant premium of $517.

2.6 ASC 960 (plan accounting) information

All monetary amounts shown in US Dollars

	Present Value
A Present Value of Accumulated Benefits	
1 Vested accumulated benefits	
a Active employees	13,530,598
b Participants with deferred benefits	3,393,100
c Participants receiving benefits	76,119,601
d Total vested accumulated benefits	93,043,299
2 Non-vested accumulated benefits	1,831,654
3 Total accumulated benefits	94,874,953
4 Market value of assets[1]	109,087,777
B Reconciliation of Present Value of Accumulated Benefits	
1 Present value of accumulated benefits as of December 31, 2015	96,344,812
2 Changes during the year due to:	
a Benefits accumulated	710,963
b Actuarial (gains)/losses	(2,425)
c Decrease in the discount period	4,820,072
d Actual benefits paid	(7,012,311)
e Assumption changes	0
f Plan amendments	13,842
g Net increase/(decrease)	(1,469,859)
3 Present value of accumulated benefits as of December 31, 2016	94,874,953

Actuarial Assumptions and Methods

The present value of accumulated benefits was developed using the actuarial assumptions described in Appendix A, except a discount rate of 5.15% was used, and the mortality assumed was RP-2014 employee and annuitant tables (no collar adjustments) adjusted back to 2006 with MP-2014, and projected forward using the MP-2015 generational improvement scale. The discount rate used is the same as the expected rate of return on plan assets for the plan year under ASC 715-30-35 and, as required by that standard and further discussed in the Actuarial Certification of this report, was selected by the plan sponsor with the concurrence of Willis Towers Watson. We understand that the expected return on assets assumption reflects the plan sponsor's estimate of future experience for trust asset returns, reflecting the plan's current asset allocation and any expected changes during the current plan year, current market conditions and the plan sponsor's expectations for future market conditions. The analysis was informed by analysis of historical data, economists' forecasts and recent trends for CPI, GDP growth, and real returns on the various classes of assets held by the trust. For the prior valuation, a discount rate of 5.15% was used.

[1] Assets include accrued contributions for the 2016 plan year of $ 0 not yet deposited at January 1, 2017.

Plan Provisions

Plan provisions reflected in these calculations are described in Appendix B.

Accumulated and Vested Benefits

Accumulated benefits include benefits earned under the plan's benefit formula based on service rendered and compensation earned before the measurement date.

Benefits included in vested benefits are the same as described above for accrued benefits, except the following benefits are excluded:

- For participants who are not disabled on the measurement date, disability benefits in excess of the value of standard termination benefits (retirement benefits for those eligible).
- For participants who have not yet satisfied the eligibility requirements for these benefits, early retirement benefits and supplements in excess of standard termination benefits.
- Death benefits in excess of the plan's QPSA.
- All benefits for participants who are not yet vested in their accrued benefits or eligible for other benefits.

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Section 3: Participant data

3.1 Summary of plan participants

All monetary amounts shown in US Dollars

Census Date			01/01/2017	01/01/2016
A	Active Employees			
	1	Number	82	88
	2	Expected plan compensation for year beginning on the valuation date (limited by IRC §401(a)(17))	7,688,777	7,021,658
	3	Average plan compensation	93,766	79,792
	4	Average age	47.04	47.11
	5	Average credited service	18.07	17.94
B	Participants with Deferred Benefits			
	1	Number	71	76
	2	Total annual pension	475,236	757,294
	3	Average annual pension	6,693	9,964
	4	Average age	55.31	54.78
	5	Distribution at January 1, 2017		

Age	Number	Annual Pension
Under 40	2	12,964
40-44	5	39,031
45-49	9	57,056
50-54	16	174,414
55-59	18	104,593
60-64	13	58,796
65 and over	8	28,382

			01/01/2017	01/01/2016
C	Participants Receiving Benefits			
	1	Number	524	524
	2	Total annual pension	6,480,525	6,484,964
	3	Average annual pension	12,367	12,376
	4	Average age	71.13	70.48
	5	Distribution at January 1, 2017		

Age	Number	Annual Pension
Under 55	3	20,687
55-59	36	344,141
60-64	108	1,359,033
65-69	126	1,421,895
70-74	85	1,164,367
75-79	79	1,100,649
80-84	40	537,653
85 and over	47	532,100

3.2 Age and service distribution of participating employees

Number and average plan compensation limited by IRC §401(a)(17) distributed by attained age and attained years of credited service

All monetary amounts shown in US Dollars

	Attained Years of Credited Service[1]													
Attained Age	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25-29	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30-34	0	0	0	0	0	4	3	0	0	0	0	0	0	7
35-39	0	0	0	0	0	5	11	0	0	0	0	0	0	16
40-44	0	0	0	0	0	1	4	2	0	0	0	0	0	7
45-49	0	0	0	0	0	0	13	2	1	2	0	0	0	18
50-54	0	0	0	0	0	2	1	3	2	6	4	0	0	18
55-59	0	0	0	0	0	0	2	1	1	4	4	2	0	14
60-64	0	0	0	0	0	0	0	0	0	0	0	0	1	1
65-69	0	0	0	0	0	0	0	0	0	0	0	0	1	1
70 & over	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	12	34	8	4	12	8	2	2	82
Average Pay							88,771							93,766
Average:	Age	47		Number of Participants:		Fully vested			82	Males		76		
	Service	18				Partially vested			0	Females		6		
Census data as of January 1, 2017														

1 Age and service for purposes of determining category are based on exact (not rounded) values.

Appendix A – Statement of actuarial assumptions, methods and data sources

Economic Assumptions

Interest rate basis:

■ Applicable month	January
■ Interest rate basis	3-Segment Rates

Interest rates:

	Reflecting Corridors	Not Reflecting Corridors
■ First segment rate	4.16%	1.57%
■ Second segment rate	5.72%	3.77%
■ Third segment rate	6.48%	4.73%
■ Effective interest rate	5.82%	3.97%

Annual rates of increase

■ Compensation:	
■ Administrative employees	4.50%
■ Non-Administrative employees	4.00%
■ Future Social Security wage bases	3.50%
■ Statutory limits on compensation	2.50%
■ Interest crediting rate	3.05%
Administrative and investment expenses	$602,000

Demographic and Other Assumptions

Inclusion date	The valuation date coincident with or next following the date on which the employee becomes a participant.
New or rehired employees	It was assumed there will be no new or rehired employees.
Benefit commencement dates	
■ Preretirement death benefit	
■ Administrative	Upon death of the active participant
■ Non-Administrative	Upon the later of the death of the active participant or the date the participant would have attained earliest retirement age.
■ Deferred vested benefit	
■ Administrative	Upon termination of employment
■ Non-Administrative	Upon the later of attainment of normal retirement age or termination of employment.
■ Disability benefit	Upon disablement
■ Retirement benefit	Upon termination of employment
Form of payment	
■ Administrative	100% of participants are assumed to elect an immediate lump sum.
■ Non-Administrative	100% of single participants are assumed to elect a lifetime monthly annuity. 100% of married participants assumed to elect a 50% Joint and Survivor annuity.

Mortality for annuity conversion basis for PEP account balances and lump sums
417(e)(3) applicable mortality table

Percent married
80% of males; 50% of females

Spouse age
Wife three years younger than husband

Cash flow

- Timing of benefit payments
Annuity payments are payable monthly at the beginning of the month and lump sum payments are payable on date of decrement.

Demographic Assumptions

Mortality – Healthy & Disabled
Separate rates for non-annuitants (based on RP-2000 “Employees” table without collar or amount adjustments, projected to 2032 using Scale AA) and annuitants (based on RP-2000 “Healthy Annuitants” table without collar or amount adjustments, projected to 2024 using Scale AA).

Disability
Rates Varying by Age and Gender
Representative Disability Rates

Percentage assumed to become disabled during the year		
Attained Age	Males	Females
20	0.030%	0.040%
25	0.030%	0.050%
30	0.040%	0.060%
35	0.050%	0.080%
40	0.070%	0.100%
45	0.100%	0.150%
50	0.180%	0.260%
55	0.360%	0.490%
60	0.900%	1.210%
65	0.000%	0.000%

Termination

Rates Varying by Age and Gender
Representative Termination Rates

Percentage assumed to leave during the year		
Attained Age	Males	Females
25	5.0%	10.0%
30	4.7%	9.4%
35	3.3%	6.7%
40	1.4%	2.7%
45	0.6%	1.2%
50	0.2%	0.5%
55	0.0%	0.0%
60	0.0%	0.0%

Retirement

Rates Varying by Age and Plan
Representative Retirement Rates

Percentage assumed to retire during the year		
Age	Administrative	Non-Administrative
55	5%	5%
56	5%	5%
57	5%	5%
58	15%	20%
59	10%	15%
60	20%	30%
61	20%	40%
62	60%	80%
63	30%	50%
64	50%	50%
65	100%	100%

Methods (for all plans)

Valuation date	First day of plan year
Funding target	Present value of accrued benefits as required by regulations under IRC §430.
Target normal cost	Present value of benefits expected to accrue during the plan year plus plan-related expenses expected to be paid from plan assets during the plan year as required by regulations under IRC §430.
Actuarial value of assets for determining minimum required contributions	Average of the fair market value of assets on the valuation date and 12 and 24 months preceding the valuation date, adjusted for contributions, benefits, administrative expenses and expected earnings with such expected earnings limited as described in IRS Notice 2009-22). The average asset value must be within 10% of market value, including discounted contributions receivable (discounted using the effective interest rate for the prior plan year.) The method of computing the actuarial value of assets complies with rules governing the calculation of such values under the Pension Protection Act of 2006 (PPA). These rules produce smoothed values that reflect the underlying market value of plan assets but fluctuate less than the market value. As a result, the actuarial value of assets will be lower than the market value in some years and greater in other years. However, over the long term under PPA's smoothing rules, the method has a significant bias to produce an actuarial value of assets that is below the market value of assets.
Benefits not valued	All benefits described in the Plan Provisions were valued as described. Willis Towers Watson is not aware of any significant benefits required to be valued that were not.

Sources of Data and Other Information

The plan sponsor furnished participant data and claims data as of 1/1/2017. Information on assets, contributions and plan provisions was supplied by the plan sponsor. Data and other information were reviewed for reasonableness and consistency, but no audit was performed. Based on discussions with the plan sponsor, assumptions or estimates were made when data were not available, and the data was adjusted to reflect any significant events that occurred between the date the data was collected and the measurement date. In consultations with the Company, the following assumptions were made for missing or apparently inconsistent data elements: for missing beneficiary dates of birth, females were assumed to be 3 years younger than males; for missing beneficiary sexes, male participants were assumed to have a female beneficiary and female participants were assumed to have a male beneficiary; for deferred participants, the benefit commencement date was assumed to be the date the participant reaches age 65.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Assumptions Rationale - Significant Economic Assumptions

Discount rate	The basis chosen was selected by the plan sponsor from among choices prescribed by law all of which are based on observed market data over certain periods of time.
Interest crediting rate	The plan will credit interest to the frozen pension equity plan accounts using the first segment rate defined under the Pension Protection Act for use in determining minimum lump distribution under IRC 417(e)(3). The plan sponsor has selected a single rate. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Annuity conversion rate	The annuity conversion rate is based on the current market rates. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Lump sum conversion rate	Lump sum benefits are valued based on the current market rates. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Rates of increase in compensation, National Average Wages (NAW), and CPI	Assumed increases are based on historical data, current conditions and an estimate of future experience.

Assumptions Rationale - Significant Demographic Assumptions

Healthy Mortality Assumptions used for funding are as prescribed by IRC §430(h).

Disabled Mortality Assumptions used for funding are as prescribed by IRS §430(h).

Termination Termination rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual termination experience different than expected.

Disability Disability rates are based on a standard UAW table. Actual experience is not material to set plan-specific rates.

Retirement Retirement rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual retirement experience different than expected.

Benefit commencement date for deferred benefits:

- Deferred vested benefit — Deferred vested participants are assumed to begin benefits at age 65 (or current age if later) because the plan's experience is not considered to be credible.

Form of payment Retiring Administrative participants are assumed to take a lump sum due to the design of the plan.

Retiring Non-Administrative participants are assumed to take a 50% joint and survivor annuity if married and a single life annuity if single. These are the normal forms under the plan.

Marital Assumptions:

- Percent married — The assumed percentage married is based on general population statistics on the marital status of individuals of retirement age.
- Spouse age — The assumed age difference for spouses is based on general population statistics of the age difference for married individuals of retirement age.

Source of Prescribed Methods

Funding methods

The methods used for funding purposes as described in Appendix A, including the method of determining plan assets, are “prescribed methods set by law”, as defined in the actuarial standards of practice (ASOPs). These methods are required by IRC §430, or were selected by the plan sponsor from a range of methods permitted by IRC §430.

Changes in Assumptions and Methods

Change in assumptions since prior valuation

The segment interest rates used to calculate the funding target and target normal cost were updated to the current valuation date as required by IRC 430.

The mortality table used to calculate the funding target and target normal cost was updated to include one additional year of projected mortality improvement, as required by IRC 430.

The assumed plan-related expenses added to the target normal cost were changed from $550,000 for the prior valuation to $602,000 for the current valuation to account for higher expected expenses to be paid from the trust.

The interest crediting rate was changed from 3.00% from the prior valuation to 3.05% for the current valuation.

Change in methods since prior valuation

No changes in methods since prior valuation

Appendix B – Summary of principal plan provisions

Plan Provisions – Upper Peninsula Power Company Retirement Plan

Upper Peninsula Power Company Retirement Plan is closed to new entrants, effective as follows:

- Administrative employees effective January 1, 2008
- Non-Administrative employees effective April 19, 2009

Retirement Program for Administrative Employees

Employees included	Except for anyone who is subject to a collective bargaining agreement, an employee became a participant on January 1 or July 1 coincident with or next following the date of completion of one year of eligibility service subject to the provisions concerning closure of the plan to new entrants.

Definitions

Service considered	Year of “Eligibility Service” is the twelve month period commencing on the date of hire or rehire, or any plan year in which the employee completes 1,000 or more hours of service. “Service credit,” to determine eligibility for and the amount of benefits, is determined under the ERISA elapsed-time rules. Service credit will be earned while the employee is receiving benefits from the long-term disability plan sponsored by the company. No additional benefit service will accrue after December 31, 2012.
Compensation considered	Total compensation prior to severance from service excluding nonqualified deferred compensation payments, and extraordinary payments. Annual compensation is limited to $200,000, adjusted in accordance with Internal Revenue Code. Final average pay is the higher of the average of (a) the highest five complete calendar years of pay within the last 10 calendar years preceding severance from service, or (b) total pay for 60 months preceding severance from service. Pay after December 31, 2017 will not be considered in the calculation of final average pay.

Eligibility for Benefits

Benefit eligibility	5 years of service (3 years for employees who terminate employment on or after January 1, 2008).

Benefits Payable

Plan Benefit

(a) Benefit payable to a plan participant with 3 years of vesting service.

(b) Total Service Percent is a total of:

9% per year for the first 10 years of service;

plus 12% per year for years 11 through 20;

plus 15% per year for years 21 and thereafter.

For employees hired after December 31, 2000, the service percentages are 9%, 11% and 13%, respectively.

(c) Pension Income (lump-sum form) is equal to Total Service Percent times Final Average Pay.

(d) Minimum benefit is the lump-sum value of the benefit earned through December 31, 2000 under the plan provisions in effect at December 31, 2000.

There will be no additional service or pay increases applied to the plan benefit after December 31, 2012 and December 31, 2017, respectively. Effective January 1, 2018 the frozen accrued benefit will be increased each year until benefit commencement with annual interest credits based on the greater of (a) the first segment rate defined under the Pension Protection Act for use in determining minimum lump-sum distributions under IRC 417(e), and (b) the plan's minimum interest crediting rate of 3.05%.

Pension transition

For employees employed on January 1, 2001:

(a) Calculated by taking combination of participant's age and service on January 1, 2001.

(b) Total age plus service is multiplied by 1.35% to arrive at Transition Percent (limited to 115%).

This percent is held constant until retirement or participant leaves the company and will be multiplied by Final Average Pay to determine the Pension Transition amount (payable as a lump sum). The minimum amount is $50,000 for employees who were at least age 58 and had five years of service at December 31, 2000.

Pension supplement

To be eligible for the Pension Supplement, participant must be

(a) employed on January 1, 2001;

(b) retire after January 1, 2001;

(c) be at least 55 years of age, and

(d) have 5 years of service with the company.

The Pension Supplement is payable as a fixed $800 monthly payment from retirement until age 65, or as a lump sum based on age at retirement and current interest rates.

For employees hired after January 1, 2001, eligibility for the supplement requires the participant to be age 55 with 10 years of service. The Pension Supplement amount is earned at a rate of $40 per year of service (earned prior to January 1, 2013).

Surviving spouse's benefit

(a) If the death of a vested participant occurs, the spouse will receive either a single-sum payment or a survivor annuity benefit. If the participant had designated a non-spouse beneficiary and the surviving spouse had consented, the beneficiary will receive a single-sum payment.

(b) If a participant who was receiving a monthly pension dies, the surviving spouse will receive payment in accordance with the joint and survivor option elected or the remainder of the Pension Equity Account Balance, if any.

Other Plan Provisions

Forms of payment

Preretirement death benefits are payable only as described above. Monthly pension benefits are paid as described above as a life annuity, if the participant has no spouse as of the date payments begin, or if the participant so elects. Otherwise, benefits are paid in the form of a 50% joint and survivor annuity option or, if the participant elects and the spouse consents, another actuarially equivalent optional form offered by the plan. Optional forms and actuarial equivalence are as follows:

Normal form of payment

Married participants receive a fully subsidized 50% joint & survivor annuity. The normal form of payment for unmarried participants is a single life annuity.

Optional forms of payment and conversion factors

Form of Payment	Conversion Factor
Lump Sum	Accrued PEP Balance at time of termination or retirement.
Annuity	PEP balance is converted to an annuity using the Applicable Mortality Table and Applicable Interest Rate.
Life Annuity	Calculated using annuity conversion factor with no further adjustment.
50% Joint and Survivor Annuity	Calculated using annuity conversion factor with no further adjustment unless spouse is more than 5 years younger than participant, in which case additional reductions apply.
75% Joint and Survivor Annuity	Calculated as 96% of life annuity benefit unless spouse is more than 5 years younger than participant, in which case additional reductions apply.

	100% Joint and Survivor Annuity	Calculated as 93% of life annuity benefit unless spouse is more than 5 years younger than participant, in which case additional reductions apply.
	Unreduced lifetime benefit	Participants whose spouse is greater than 5 years younger can elect to receive the equivalent of the life annuity benefit during their lifetime, with their spouse receiving an actuarially equivalent 50% survivor benefit, calculated using 6% interest and the 1971 Group Annuity Mortality Table.
	Additionally, participants who are administrative employees who have joined the plan through a merged prior plan may be entitled to actuarially equivalent benefits in the following forms: single life annuity, 5, 10, or 15-year certain annuity, 25% joint and survivor annuity with or without popup, 50% joint and survivor annuity with or without popup, 66 2/3% joint and survivor annuity with or without popup, 100% joint and survivor annuity with or without popup.	
Pension Increases	None	
Plan participants' contributions	None	
Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are not assumed for determining the AFTAP.	
Benefits Not Valued	All benefits described in the Plan Provisions were valued. Willis Towers Watson is not aware of any significant benefits required to be valued that were not.	

Future Plan Changes

No future plan changes were recognized in determining minimum and maximum contributions.

Changes in Benefits Valued Since Prior Year

A minimum interest crediting rate of 3.05% was added to the plan.

Retirement Program for Non-Administrative Employees

Employees Included	An employee represented by Local Union No. 510 of the IBEW became a participant upon completion of one year of service credit subject to the provisions concerning closure of the plan to new entrants.

Definitions	
Service considered	A year of service is granted for each July 1st through June 30th in which 1,000 hours are worked. In any computation period in which a participant begins, resumes, or terminates employment, 1/12th of a year of credit is given for each complete month worked.
Compensation considered	Fixed Monthly Earnings on July 1 of each year.

Eligibility for Benefits	
Normal retirement benefit	On or after attainment of age 65 or, for an individual who became a participating employee after age 60, on the 4th anniversary of his date of participation.
Early retirement benefit	Available upon reaching age 55 with 10 years of service (prior to 1/1/1993: age 45 and 10 years of service).
Deferred vested benefit	In the event of termination of employment prior to age 55 and after 10 or more years of service credit. Certain participants are granted a grandfather eligibility of age 45 and 10 years of service.
Surviving spouse benefit	In the event of death of an active participant occurring after attainment 5 years of service credit. In the event of a death of a participant who was receiving a pension under the foregoing paragraphs. In the event of death of a deferred vested participant who has not commenced the benefit and who has been married for one year as of the date of death dies prior to pension commencement date.

Benefits Payable

Normal retirement benefit	The sum of (1) 2% of Monthly Earnings as of 7/1/1980 times years of service prior to 7/1/1980 plus (2) 2% of July 1 fixed Monthly Earnings for each year after 7/1/1980 and prior to 7/1/1999 plus (3) 2.25% of July 1 fixed Monthly Earnings for each year beginning 7/1/1999.
Early retirement benefit	Monthly pension commencing as of the date designated by the participant or as of the participant's severance from service date, as the case may be, is determined in the same manner as a normal retirement benefit under the Normal Retirement Benefit paragraph above, reduced by 3% per year. Unreduced benefit becomes available upon reaching Rule of 85 for participants as of May 1, 1991.
Deferred vested benefit	Monthly pension payable as of the later of age 55 or the date designated by the employee, but not later than age 65, is determined in the same manner as an early retirement benefit under the Early Retirement Benefit paragraph
Surviving spouse benefit	The spouse to whom the participant was married to as of the date of his death will receive 50% of the pension determined under the following stipulations. This benefit will be reduced if the spouse is younger than the participant. If the death occurs after early retirement age, the base benefit is determined under the above Normal Retirement Benefit provisions, as if his date of death was his normal retirement date, based on his service credit and average monthly compensation as of his death. Payable at the later of the date of death or the date the participant would have reached age 55. If the death occurs prior early retirement age, but after 5 years of service credit and before 10 years of service credit, the base benefit is determined based upon the foregoing paragraph of Normal Retirement Benefit payable at the date the deceased member would have turned age 65. If the death occurs prior early retirement age, but after 10 years of service credit, the base benefit is determined as the total accrued monthly benefit, without reduction for early commencement. The benefit is payable on the first day of the month following the date of death. If the death of a participant who was receiving a pension under the foregoing paragraphs, the base benefit is determined as the pension the participant was receiving immediately prior to his death. If the death of a vested participant occurs prior to his pension commencement date, the base benefit is determined under the foregoing Early Retirement Benefit paragraph based on his service credit. Payable at the date of the participant’s death.

Other Plan Provisions

Lump sum payments

Small lump sums will be paid if the value of benefit is $1,000 or less ($5,000 prior to March 28, 2005). Lump sums are determined based on interest rates prescribed by the Secretary of the Treasury pursuant to Section 417(e)(3) of the Code.

Normal form of payment

Married participants receive a fully subsidized 50% joint & survivor annuity. The normal form of payment for unmarried participants is a single life annuity.

Optional forms of payment and conversion factors

Plan participants from the prior Upper Peninsula Power Company Plan are also eligible for the following forms of payment using the option factors shown:

Joint and Survivor Pension
Option Factors

Age of Participant at Retirement	Option			
	100%	75%	66-2/3%	50%
45-49	.93	.95	.95	.96
50-54	.91	.93	.94	.95
55-59	.89	.92	.92	.94
60-64	.86	.89	.90	.92
65 and above	.83	.87	.88	.91

Additional age adjustments apply for participants whose spouse has an age difference of greater than three years, subject to maximum adjustments as outlined in the plan document.

Additionally, Non-Administrative employees who are participants and joined the plan through a merged prior plan may be entitled to actuarially equivalent benefits in the following forms: single life annuity, 5, 10, or 15-year certain annuity, joint and survivor annuity with or without popup.

Pension Increases	None
Plan participants' contributions	None
Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are not assumed for determining the AFTAP.
Benefits Not Valued	All benefits described in the Plan Provisions were valued. Willis Towers Watson is not aware of any significant benefits required to be valued that were not.

Future Plan Changes

No future plan changes were recognized in determining minimum and maximum contributions.

Changes in Benefits Valued Since Prior Year

There have been no changes in the benefits valued since the prior year.

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Appendix C – Adjusted Funding Target Attainment Percentage (AFTAP)

Upper Peninsula Power Company retained Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC, to perform a valuation of its pension plan for the purpose of measuring the plan's AFTAP for the plan year beginning January 1, 2017 in accordance with ERISA and the Internal Revenue Code. This valuation has been conducted in accordance with generally accepted actuarial principles and practices.

The enrolled actuaries making this certification are members of the Society of Actuaries and other professional actuarial organizations and meet their "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States."

We hereby certify that the plan's AFTAP for the plan year beginning January 1, 2017 is 130.75%. This percentage is based on the assumptions, participant data, and plan provisions we relied upon to prepare the results shown in this report, reflects the valuation limitations discussed in this report and is also based on the following additional information:

Annuity Purchases

- Upper Peninsula Power Company's representation that there were no annuity purchases made on behalf of non-highly compensated employees by the plan in the plan years beginning in 2015 and 2016.

Funding Balances

- Our understanding is that Upper Peninsula Power Company has not elected to reduce the plan's funding balance as of the first day of the 2017 plan year.
- Our understanding is that the plan is not subject to a deemed election to reduce the funding balances in 2017.
- Our understanding is that Upper Peninsula Power Company has not elected to apply any of the plan's funding balances to the 2017 minimum required contribution.
- Our understanding is that Upper Peninsula Power Company has not elected to increase the prefunding balance as of the first day of the 2017 plan year.

Contributions

- Our understanding is that Upper Peninsula Power Company has not made any employer contributions after December 31, 2016 and before September 14, 2017 for the 2016 plan year.

Subsequent Events

- The plan was amended in 2017 to add a minimum interest crediting rate of 3.05%. This amendment was reflected in determining the plan's AFTAP.

- There were no unpredictable contingent event benefits (UCEBs) that took effect in the current plan year.

- There were no previously suspended accruals restored during the current plan year.

Elections

- Our understanding of sponsor elections required under the Pension Protection Act of 2006 (PPA), with respect to interest rates, Actuarial Value of Assets and other methods and/or assumptions, as confirmed in the Sponsor's letter dated September 13, 2017.

The development of the AFTAP is shown below:

All monetary amounts shown in US Dollars

Plan Year Beginning	01/01/2017
Actuarial value of assets as of January 1, 2017[1]	111,000,755
Funding standard carryover balance at January 1, 2017[2]	0
Prefunding balance at January 1, 2017[2]	7,366,124
Funding target (disregarding at-risk assumptions)	84,889,396
AVA/funding target (disregarding at-risk assumptions)	130.75%
Assets for AFTAP calculation[3]	111,000,755
Annuity purchases for NHCEs during 2015 and 2016	0
Reflection of Post-Valuation Date Events not Previously Reflected	
Increase in funding target (disregarding at-risk assumptions) for 2017 amendments/UCEBs/restored accruals[4]	N/A
IRC §436 contributions made to enable plan amendments/UCEBs/restored accruals to take effect[5]	N/A
Adjusted funding target, disregarding at-risk assumptions, (includes NHCE annuity purchases and amendments)	N/A
Adjusted assets (includes NHCE annuity purchases and IRC §436 contributions)	N/A
Specific AFTAP	
Adjusted Funding Target Attainment Percentage (AFTAP)	130.75%

1 Reflects discounted contributions made for the 2016 plan year only if paid on or before the certification date. Includes security posted by the beginning of the plan year in the form of a bond or cash held in escrow.
2 Reflects elections made to-date (other than elections to apply the funding balances to 2017 MRC).
3 AVA if AVA/Funding Target (disregarding at-risk assumptions) >=100%; otherwise (AVA-funding balances).
4 If amendments/UCEBs/restored accruals (i) went into effect before this specific certification, (ii) were not reflected in the funding valuation and (iii) require AFTAP recertification, or if AFTAP recertification is not required but the plan sponsor decides to reflect the amendment/UCEBs/restored accruals in the specific AFTAP certification.
5 Discounted to January 1, 2017 using the 2017 plan year effective interest rate.

Immediate Implications of AFTAP Certification

We believe that the certified AFTAP of 130.75% for the 2017 plan year has the following implications for benefit limitations described in IRC §436. Upper Peninsula Power Company should review these conclusions with ERISA counsel:

- Benefit accruals called for under the plan without regard to IRC §436 must continue.
- Accelerated distributions called for under the plan without regard to IRC §436 must continue in full.
- Amendments that increase benefits must be evaluated at the time they would take effect to determine if they are permissible.
- Plant shutdown and other UCEBs must be evaluated at the time they would take effect to determine if they are permissible.

Implications of 2017 AFTAP for Presumptions in Next Plan Year

Because the AFTAP for the 2017 plan year is at least 90%, the presumed AFTAP for 2018 will remain equal to the 2017 certified AFTAP, and changes in benefit restrictions will not occur, before the 2018 AFTAP is certified, provided that the 2018 AFTAP is certified before the first day of the tenth month of the plan year.

Note, however, that adoption of plan amendments and/or payment of UCEBs may change this result.

Georgia Louridas, FSA, EA
Senior Consulting Actuary
17-8034
September 14, 2017

Steven James, FSA, EA
Senior Consulting Actuary
17-06406
September 14, 2017

Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC

Appendix D – Descriptions of funded status measures

Calculations for Funding Ratios Chart in Section 1: Summary of Results

Prior Year Ratios

	Purpose of Ratio	Asset Measure	Obligation Measure
1	Test ability to apply funding balances to current year MRC	AVA - PFB	FTO
2	Quarterly contribution exemption test for current year	AVA – FSCB - PFB	FT
3	At-risk Prong 1 Test for current year	AVA – FSCB - PFB	FTO
4	At-risk Prong 2 Test for current year	AVA – FSCB - PFB	FTAR, but without loads

Current Year Ratios

	Purpose of Ratio	Asset Measure	Obligation Measure
1	Test ability to apply funding balances to next year's MRC	Same as for analogous Prior Year Ratio	
2	Quarterly contribution exemption test for next year		
3	At-risk Prong 1 Test for next year		
4	At-risk Prong 2 Test for next year		
5	PBGC 4010 filing gateway test (PBGC FTAP) (to determine whether a filing is required next year for the current plan year)	AVA – FSCB - PFB	FTO ignoring interest rate stabilization
6	Exemption from establishing SAB in current year:		
	- If PFB applied to current year MRC	AVA - PFB	FT
	- If PFB not applied to current year MRC	AVA	FT
7	Eliminate SABs in current year	AVA – FSCB – PFB	FT

Benefit Restriction Ratios

Purpose of Ratio for Plan Year	Assets	Obligations	Year Ratio is Determined
Adjusted Funding Target Attainment Percentage (AFTAP) – Application of Benefit Restrictions under IRC 436	[AVA if AVA/FTO >= 100%; AVA – FSCB – PFB otherwise] + annuity purchases for NHCEs in previous 2 years	FTO + annuity purchases for NHCEs in previous 2 years	Current

Definitions of terms

Term	Short for	Definition
FTAP	Funding target attainment percentage	(AVA – FSCB – PFB) / FTO
PBGC FTAP	FTAP for exemption from ERISA 4010	(AVA – FSCB – PFB) / (FTO ignoring interest rate stabilization)
FSCB	Funding standard carryover balance	Accumulated contributions in excess of those required in pre-PPA plan years, less amounts applied to MRC or forfeited
PFB	Prefunding balance	Accumulated contributions in excess of those required since PPA applied to the plan, to the extent the plan sponsor elected to create PFB, less amounts subsequently applied to MRC or forfeited
Funding balance	FSCB + PFB	
FTO	Ongoing funding target	Funding target as described in IRC 430, ignoring at-risk assumptions; equals FT for a plan that is not at-risk.
FTO ignoring stabilization	FTO calculated ignoring interest rate stabilization	Same as FTO if the full yield curve is used, or stabilized segment rates fall within the corridors
FTAR	At-risk funding target	Funding target reflecting at-risk assumptions and any applicable loads, as described in IRC 430(i), with no phase-in
FT	Funding target	Funding target used to calculate MRC. Equals: ■ FTO if the plan is not at-risk. ■ FTAR if the plan has been at risk for at least 5 consecutive plan years. ■ Otherwise, FTO + 20% * (# of consecutive years at-risk) * (the excess, if any, of FTAR over FTO).
FS	Funding shortfall (surplus)	FT – (AVA – funding balances)
PBGC 4010 FS	Funding shortfall for determining whether a controlled group is exempt from an ERISA 4010 filing	FT (ignoring interest rate stabilization) - AVA See PBGC reporting requirements section of the report for more information.
SAB	Shortfall amortization base	An SAB is established each year equal to the FS less the present value of the SAIs related to SABs established in earlier years. A plan may be exempt from establishing an SAB for a plan year in accordance with the test in the Funding Ratios chart in section 1.

Term	Short for	Definition
TNC	Target normal cost	Present value of benefits expected to accrue, and expenses expected to be paid from plan assets, for the year. Reflects at-risk assumptions if the plan is at-risk (phased-in if plan has been at-risk for fewer than 5 consecutive years as described above)
SAI	Shortfall amortization installment	Amortization for an SAB established in a particular year. SAIs are eliminated if FS is less than or equal to $0.
MRC	Minimum required contribution	TNC plus SAIs as of the valuation date (assumes no funding waivers and plan is not fully funded). See section 2.4 for more details on this calculation.
AVA	Actuarial value of assets	"Plan assets" under PPA, including discounted receivables and reflecting any smoothing. See section 2.3 for more details.

Upper Peninsula Power Company

Actuarial Valuation Report
Benefit Cost for Fiscal Year Beginning
January 1, 2017 under US GAAP

August 2017

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Purposes of valuation

Upper Peninsula Power Company engaged Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC ("Willis Towers Watson") to value the Company's other postretirement benefit plan.

As requested by Upper Peninsula Power Company (the Company), this report documents the results of an actuarial valuation of the Plans:

- Upper Peninsula Power Company Administrative Medical and Dental Plan
- Upper Peninsula Power Company Non-Administrative Medical and Dental Plan
- Upper Peninsula Power Company Retiree Life Insurance Plan

The primary purpose of this valuation is to determine the Net Periodic Postretirement Benefit Cost/ (Income) (Benefit Cost), in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715) for the fiscal year beginning January 1, 2017. It is anticipated that a separate report will be prepared for year-end financial reporting purposes.

Limitations

This valuation has been conducted for the purposes described above and may not be suitable for any other purpose. In particular, please note the following:

1. The expected contribution to the other postretirement benefits plan(s) has been set at $0.

   Note that any significant change in the amounts contributed or expected to be contributed in 2017 will require disclosure in the interim financial statements, but should not affect the expected return on plan assets absent a remeasurement for another purpose.

2. There may be certain events that have occurred since the valuation date that are not reflected in the current valuation. See Subsequent Events in the Basis for Valuation section below for more information.

3. This report does not provide information for plan reporting under ASC 960 or ASC 965.

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Section 1: Summary of key results

Benefit cost, assets & obligations

All monetary amounts shown in US Dollars

Plan Name		Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Beginning		**01/01/2017**	**01/01/2017**	**01/01/2017**	**01/01/2017**
Benefit Cost/ (Income)	Net Periodic Benefit Cost/(Income)	61,337	36,206	(82,853)	107,984
	Immediate Recognition of Benefit Cost/(Income) due to Special Events	0	0	0	0
	Total Benefit Cost/(Income)	61,337	36,206	(82,853)	107,984
Measurement Date		**01/01/2017**	**01/01/2017**	**01/01/2017**	**01/01/2017**
Plan Assets	Fair Value of Assets (FVA)	24,560,029	1,727,653	21,935,988	896,388
	Market Related Value of Assets (MRVA)	23,573,372	1,765,225	20,948,571	859,576
	Return on Fair Value Assets during Prior Year	5.01%	1.15%	5.29%	5.96%
Benefit Obligations	Accumulated Postretirement Benefit Obligation (APBO)	(25,225,963)	(2,461,018)	(20,447,929)	(2,317,016)
Funded Ratios	Fair Value of Assets to APBO	97.4%	70.2%	107.3%	38.7%
Accumulated Other Comprehensive (Income)/Loss	Net Prior Service Cost/(Credit)	(6,619,347)	(1,318,260)	(5,315,483)	14,396
	Net Loss/(Gain)	5,388,156	2,446,353	2,025,267	916,536
	Total Accumulated Other Comprehensive (Income)/Loss	(1,231,191)	1,128,093	(3,290,216)	930,932
Assumptions	Discount Rate	4.10%	3.70%	4.15%	4.00%
	Expected Long-term Rate of Return on Plan Assets - VEBA	5.00%	3.35%	5.15%	5.15%
	Expected Long-term Rate of Return on Plan Assets – 401(h)	5.15%	5.15%	N/A	N/A
	Current Health Care Cost Trend Rate	6.50%	6.50%	6.50%	N/A
	Ultimate Health Care Cost Trend Rate	5.00%	5.00%	5.00%	N/A
	Year of Ultimate Trend Rate	2023	2023	2023	N/A
Participant Data	Census Date	01/01/2017	01/01/2017	01/01/2017	01/01/2017

Comments on results

The actuarial gains/(losses) due to demographic experience, including any assumption changes, and investment return different from assumed during the prior year were $4,576,911 and $83,749 respectively.

Change in net periodic cost and funded position

The net periodic cost declined from $740,281 in fiscal 2016 to $61,337 in fiscal 2017 and the funded position improved from ($4,461,011) to ($665,934).

Significant reasons for these changes include the following:

- The return on the fair value of plan assets since the prior measurement date was greater than expected, which improved the funded position.
- The discount rate decreased, which increased the net periodic cost and caused the funded position to deteriorate. Specifically:
  - The discount rate for the Administrative Medical and Dental Plan decreased by 0.15%
  - The discount rate for the Non-Administrative Medical and Dental Plan decreased by 0.25%
  - The discount rate for the Retiree Life Insurance Plan decreased by 0.20%
- The claims cost and retiree premiums were updated based on actual 2017 information which reduced the net periodic cost and improved the funded position.
- The actual demographic experience was different than expected, which reduced the net periodic cost and improved the funded position.

Effects of Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act (PPACA) and Health Care and Education Reconciliation Act (HCERA) were enacted. The key aspect of the Acts affecting the Company's benefit obligation and cost of providing retiree medical benefits is the estimated excise ("Cadillac") tax on high-cost plans beginning in 2020

This valuation reflects our understanding of the relevant provisions of PPACA and HCERA. The IRS has yet to issue final guidance with respect to many aspects of these laws. It is possible that future guidance may conflict with our understanding of these laws based on currently available guidance and could therefore affect the results shown in this report. The valuation does not anticipate the effects of any possible future changes to PPACA or HCERA.

Basis for valuation

Appendix A summarizes the assumptions and methods used in the valuation. Appendix B summarizes our understanding of the principal provisions of the plan being valued. Unless otherwise described below under Subsequent Events, assumptions were selected based on information known as of the measurement date.

Changes in assumptions

There were no changes in assumptions from the year-end 2016 disclosure report.

Changes in methods

There were no changes in methods from the year-end 2016 disclosure report.

Changes in benefits valued

There were no changes in benefits valued from the year-end 2016 disclosure report.

Subsequent events

To the best of our knowledge, there are no material events that occurred after the valuation date.

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Actuarial certification

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. However, please note the information discussed below regarding this valuation.

Reliances

In preparing the results presented in this report, we have relied upon information regarding plan provisions, participants, assets, and sponsor accounting policies and methods provided by the Company and other persons or organizations designated by the Company. See the Data Sources section of Appendix A for further details. We have relied on all the data and information provided as complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by the Company, may produce materially different results that could require that a revised report be issued.

Measurement of benefit obligations, plan assets and balance sheet adjustments

Census date/measurement date

The measurement date is January 1, 2017. The benefit obligations were measured as of January 1, 2017 and are based on participant data as of the census date, January 1, 2017.

Plan assets and balance sheet adjustments

Information about the fair value of plan assets was furnished to us by the Company. The Company also provided information about the general ledger account balances for the other postretirement benefit plan cost at December 31, 2016, which reflect the expected funded status of the plans before adjustment to reflect the funded status based on the year-end measurements, and differences between the expected Medicare Part D subsidies and amounts received during the year. Willis Towers Watson used information supplied by the Company regarding postretirement benefit asset, postretirement benefit liability and amounts recognized in accumulated other comprehensive income as of December 31, 2016. This data was reviewed for reasonableness and consistency, but no audit was performed.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for tax effects. Any tax effects in AOCI should be determined in consultation with the Company's tax advisors and auditors.

Assumptions and methods under U.S. GAAP

As required by U.S. GAAP, the actuarial assumptions and methods employed in the development of the other postretirement benefit cost and other financial reporting have been selected by the Company. Willis Towers Watson has concurred with these assumptions and methods. U.S. GAAP requires that each significant assumption “individually represent the best estimate of a particular future event.”

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

A summary of the assumptions and methods used is provided in Appendix A. Note that any subsequent changes in methods or assumptions for the January 1, 2017 measurement date will change the results shown in this report.

Nature of actuarial calculations

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. Any rounding (or lack thereof) used for displaying numbers in this report is not intended to imply a degree of precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions, changes in economic or demographic assumptions, increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period), and changes in plan provisions or applicable law. Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements. Retiree group benefits models necessarily rely on the use of approximations and estimates, and are sensitive to changes in these approximations and estimates. Small variations in these approximations and estimates may lead to significant changes in actuarial measurements.

See Basis for Valuation in Section 1 above for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

Limitations on use

This report is provided subject to the terms set out herein and in our engagement letter dated April 8, 2014 and any accompanying or referenced terms and conditions.

The information contained in this report was prepared for the internal use of the Company and its auditors in connection with our actuarial valuation of the other postretirement benefit plan as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. The Company may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require the Company to provide them this report, in which case the Company will use best efforts to notify Willis Towers Watson in advance of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

Professional qualifications

The undersigned are members of the Society of Actuaries and meet the “Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States” relating to other postretirement benefit plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC (“Willis Towers Watson”).

Georgia Louridas, FSA, EA
Valuation Actuary
August 17, 2017

Steven James, FSA, EA
Valuation Actuary
August 17, 2017

Anthony R. Simone

Anthony Simone, FSA, MAAA
Pricing Specialist
August 17, 2017

August 2017

The Pricing Specialist is responsible for developing and/or determining the reasonableness of retiree welfare plan trend and participation assumptions as well as assumed per capita claims costs (including the aging/morbidity assumption if applicable). The Valuation Actuary is responsible for other aspects of the valuation (e.g., developing and/or reviewing the reasonableness of other valuation assumptions and methods, ensuring that the valuation model reasonably reflects the substantive plan and actual plan operation, preparing demographic data, performing the valuation, implementing the correct accounting or funding calculations, etc.).

Section 2: Accounting exhibits

2.1 Balance sheet asset/(liability)

All monetary amounts shown in US Dollars

		Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
		Measurement Date	**01/01/2017**	**01/01/2017**	**01/01/2017**	**01/01/2017**
A		**Development of Balance Sheet Asset/(Liability)[1]**				
	1	Accumulated postretirement benefit obligation (APBO)	(25,225,963)	(2,461,018)	(20,447,929)	(2,317,016)
	2	Fair value of assets (FVA) [2]	24,560,029	1,727,653	21,935,988	896,388
	3	Net balance sheet asset/(liability)	(665,934)	(733,365)	1,488,059	(1,420,628)
B		**Current and Noncurrent Allocation[3]**				
	1	Noncurrent asset	1,488,059	0	1,488,059	0
	2	Current liability	(20,714)	(20,714)	0	0
	3	Noncurrent liability	(2,133,279)	(712,651)	0	(1,420,628)
	4	Net balance sheet asset/(liability)	(665,934)	(733,365)	1,488,059	(1,420,628)
C		**Accumulated Other Comprehensive (Income)/Loss**				
	1	Net prior service cost/(credit)	(6,619,347)	(1,318,260)	(5,315,483)	14,396
	2	Net loss/(gain)	5,388,156	2,446,353	2,025,267	916,536
	3	Accumulated other comprehensive (income)/loss[4]	(1,231,191)	1,128,093	(3,290,216)	930,932
D		**Assumptions and Dates**				
	1	Discount rate	4.10%	3.70%	4.15%	4.00%
	3	Current health care cost trend rate	6.50%	6.50%	6.50%	N/A
	4	Ultimate health care cost trend rate	5.00%	5.00%	5.00%	N/A
	5	Year of ultimate trend rate	2023	2023	2023	N/A
	6	Census date	01/01/2017	01/01/2017	01/01/2017	01/01/2017

1 Whether the amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.
2 Excludes receivable contributions.
3 The current liability (for each underfunded plan) was measured as the discounted value of benefits expected to be paid over the next 12 months in excess of the fair value of the plan's assets at the measurement date.
4 Amount shown is pre-tax and should be adjusted by plan sponsor for tax effects.

2.2 Changes in liabilities and assets

All monetary amounts shown in US Dollars

Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Beginning	**01/01/2017**	**01/01/2017**	**01/01/2017**	**01/01/2017**
A Change in Accumulated Postretirement Benefit Obligation (APBO)				
1 APBO at beginning of prior fiscal year	29,131,220	2,688,405	24,096,164	2,346,651
2 Employer service cost	742,926	53,479	679,506	9,941
3 Interest cost	1,262,410	101,131	1,065,178	96,101
4 Actuarial loss/(gain)	(4,576,911)	(155,949)	(4,494,929)	73,967
5 Plan participants' contributions	651,280	208,663	442,617	0
6 Benefits paid from plan assets[1]	(1,976,962)	(434,711)	(1,340,607)	(209,644)
7 Benefits paid from the Company[1]	0	0	0	0
8 Medicare Part D subsidy	0	0	0	0
9 Administrative expenses paid[2]	0	0	0	0
10 Plan change	0	0	0	0
11 Acquisitions/(divestitures)	0	0	0	0
12 Curtailments	0	0	0	0
13 Settlements	0	0	0	0
14 Special/contractual termination benefits	0	0	0	0
15 APBO at beginning of current fiscal year	25,225,963	2,461,018	20,447,929	2,317,016
B Change in Plan Assets				
1 Fair value of assets at beginning of prior fiscal year	24,670,209	1,914,285	21,708,342	1,047,582
2 Actual return on assets	1,202,741	20,826	1,125,636	56,279
3 Employer contributions	20,761	18,590	0	2,171
4 Plan participants' contributions	651,280	208,663	442,617	0
5 Benefits paid[1]	(1,984,962)	(434,711)	(1,340,607)	(209,644)
6 Administrative expenses paid	0	0	0	0
7 Transfer payments				
8 Acquisitions/(divestitures)	0	0	0	0
9 Settlements	0	0	0	0
10 Fair value of assets at beginning of current fiscal year	24,560,029	1,727,653	21,935,988	896,388

1 Net of retiree contributions.
2 Only if future expenses are accrued in APBO through a load on service cost.

2.3 Summary of net balances

All monetary amounts shown in U.S. Dollars

Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Beginning	01/01/2017	01/01/2017	01/01/2017	01/01/2017
A Summary of Net Prior Service Cost/(Credit)				
1 Net amount at current fiscal year begin	(6,619,347)	(1,318,260)	(5,315,483)	14,396
2 Amortization amount during current fiscal year	850,381	214,817	637,221	(1,657)
3 Effect of curtailments	0	0	0	0
4 Other events	0	0	0	0
B Summary of Net Loss/(Gain)				
1 Net amount at current fiscal year begin	5,388,156	2,446,353	2,025,267	916,536
2 Amortization amount during current fiscal year	(850,381)	(195,521)	(58,278)	(45,633)
3 Effect of curtailments	0	0	0	0
4 Effect of settlements	0	0	0	0

2.4 Development of assets for benefit cost

All monetary amounts shown in U.S. Dollars

Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Ending	**12/31/2016**	**12/31/2016**	**12/31/2016**	**12/31/2016**
A Development of Market-Related Value of Assets - VEBA	23,004,385	172,009	21,935,988	896,388
1 Fair value of assets at current fiscal year end				
2 Deferred investment gains/(losses) for prior periods				
Fiscal Year Gain/(Loss)				
a 12/31/2016	102,202	(44,670)	136,784	10,088
b 12/31/2015	(315,776)	(21,388)	(267,652)	(26,736)
c 12/31/2014	1,451,589	(153)	1,408,338	43,404
d 12/31/2013	2,496,449	(16,892)	2,376,231	137,110
e 12/31/2012	1,960,995	(23,640)	1,867,365	117,270
Percent Deferred				
a 12/31/2016	80%	80%	80%	80%
b 12/31/2015	60%	60%	60%	60%
c 12/31/2014	40%	40%	40%	40%
d 12/31/2013	20%	20%	20%	20%
e 12/31/2012	0	0	0	0
Deferred Amount				
a 12/31/2016	81,761	(35,736)	109,427	8,070
b 12/31/2015	(189,466)	(12,833)	(160,591)	(16,042)
c 12/31/2014	580,636	(61)	563,335	17,362
d 12/31/2013	499,290	(3,378)	475,246	27,422
e 12/31/2012	0	0	0	0
3 Market-related value of assets	22,032,164	224,017	20,948,571	859,576
B Development of Market-Related Value of Assets – 401(h)				
1 Fair value of assets at current fiscal year end	1,555,644	1,555,644	N/A	N/A
2 Deferred investment gains/(losses) for prior periods				
Fiscal Year Gain/(Loss)				
a 12/31/2016	(19,228)	(19,228)	N/A	N/A
b 12/31/2015	(1,832)	(1,832)	N/A	N/A
c 12/31/2014	(52,852)	(52,852)	N/A	N/A
d 12/31/2013	260,292	260,292	N/A	N/A
e 12/31/2012	205,325	205,325	N/A	N/A
Percent Deferred				
a 12/31/2016	80%	80%	N/A	N/A
b 12/31/2015	60%	60%	N/A	N/A
c 12/31/2014	40%	40%	N/A	N/A
d 12/31/2013	20%	20%	N/A	N/A
e 12/31/2012	0%	0%	N/A	N/A
Deferred Amount				
a 12/31/2016	(15,382)	(15,382)	N/A	N/A
b 12/31/2015	(1,099)	(1,099)	N/A	N/A
c 12/31/2014	(21,141)	(21,141)	N/A	N/A
d 12/31/2013	52,058	52,058	N/A	N/A
e 12/31/2012	0	0	N/A	N/A
3 Market-related value of assets	1,541,208	1,541,208	N/A	N/A

2.4 Development of assets for benefit cost (cont.)

Plan Name		Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Ending		**12/31/2016**	**12/31/2016**	**12/31/2016**	**12/31/2016**
A Development of Market-Related Value of Assets - VEBA		24,560,029	1,727,653	21,935,988	896,388
1 Fair value of assets at current fiscal year end					
2 Deferred investment gains/(losses) for prior periods					
Fiscal Year Gain/(Loss)					
a	12/31/2016	82,974	(63,898)	136,784	10,088
b	12/31/2015	(317,608)	(23,220)	(267,652)	(26,736)
c	12/31/2014	1,398,737	(53,005)	1,408,338	43,404
d	12/31/2013	2,756,741	243,400	2,376,231	137,110
e	12/31/2012	2,166,320	181,685	1,867,365	117,270
Percent Deferred					
a	12/31/2016	80%	80%	80%	80%
b	12/31/2015	60%	60%	60%	60%
c	12/31/2014	40%	40%	40%	40%
d	12/31/2013	20%	20%	20%	20%
e	12/31/2012	0	0	0	0
Deferred Amount					
a	12/31/2016	66,379	(51,118)	109,427	8,070
b	12/31/2015	(190,565)	(13,932)	(160,591)	(16,042)
c	12/31/2014	559,495	(21,202)	563,335	17,362
d	12/31/2013	551,348	48,680	475,246	27,422
e	12/31/2012	0	0	0	0
3 Market-related value of assets		23,573,372	1,765,225	20,948,571	859,576

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2.5 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Ending	**12/31/2017**	**12/31/2017**	**12/31/2017**	**12/31/2017**
A Total Benefit Cost				
1 Employer service cost	753,091	48,591	693,439	11,061
2 Interest cost	1,039,394	89,025	859,988	90,381
3 Expected return on assets	(1,180,199)	(82,114)	(1,057,337)	(40,748)
4 Subtotal	612,286	55,502	496,090	60,694
5 Net prior service cost/(credit) amortization	(850,381)	(214,817)	(637,221)	1,657
6 Net loss/(gain) amortization	299,432	195,521	58,278	45,633
7 Subtotal	(550,949)	(19,296)	(578,943)	47,290
8 Net periodic benefit cost/(income)	61,337	36,206	(82,853)	107,984
9 Curtailments	0	0	0	0
10 Settlements	0	0	0	0
11 Special/contractual termination benefits	0	0	0	0
12 Total benefit cost	61,337	36,206	(82,853)	107,984
B Assumptions and details				
1 Discount rate	4.10%	3.70%	4.15%	4.00%
2 Long-term rate of return on assets - VEBA	5.00%	3.35%	5.15%	5.15%
3 Long-term rate of return on assets – 401(h)	5.15%	5.15%	N/A	N/A
4 Current health care cost trend rate	6.50%	6.50%	6.50%	N/A
5 Ultimate health care cost trend rate	5.00%	5.00%	5.00%	N/A
6 Year of ultimate health care cost trend rate	2023	2023	2023	N/A
7 Census date	1/1/2017	1/1/2017	1/1/2017	1/1/2017
C Assets at Beginning of Year				
1 Fair market value	24,560,029	1,727,653	21,935,988	896,388
2 Market-related value	23,573,372	1,765,225	20,948,571	859,576
D Cash Flow				
i Expected				
1 Employer contributions	0	0	0	0
2 Plan participants' contributions	0	0	0	0
3 Benefits paid from the Company	21,094	21,094	0	0
4 Benefits paid from plan assets	1,172,431	187,867	846,136	138,428

Section 3: Participant Data

3.1 Participant information

All monetary amounts shown in U.S. Dollars

Plan Name		Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Measurement Date		01/01/2017	01/01/2017	01/01/2017	01/01/2017
Census Date		N/A	01/01/2017	01/01/2017	01/01/2017
Participating Employees	Number of Fully Eligible	13	1	12	12
	Number of Other	103	25	78	78
	Total Number	116	26	90	90
	Average Age	43.77	49.31	42.17	42.39
	Average Service	13.60	19.02	12.04	12.04
Retirees Dependents and Surviving Spouses	Retirees	267	33	125	223
	Average Age for Retirees	73.64	81.94	72.32	74.65
	Dependents	106	22	84	0
	Average Age for Dependents	69.91	77.59	67.89	0.00
	Surviving Spouses	53	21	32	0
	Average Age for Surviving Spouses	81.22	82.86	80.16	0.00
	Total	426	76	241	223
Other Participants	Number	4	0	4	0
	Average Annual Benefit Payments	N/A	N/A	N/A	N/A

3.2 Age and service distribution of participating employees (Administrative Medical)

Attained Age	Attained Years of Credited Service and Number													
	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25-29	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30-34	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35-39	0	0	1	0	0	1	3	0	0	0	0	0	0	5
40-44	0	0	0	0	1	0	1	0	0	0	0	0	0	2
45-49	0	0	0	0	0	1	4	0	1	1	0	0	0	7
50-54	0	0	0	0	0	0	1	0	0	3	2	0	0	6
55-59	0	0	0	0	0	0	1	1	0	1	1	0	0	4
60-64	0	0	0	0	0	0	0	0	0	0	0	0	1	1
65-69	0	0	0	0	0	0	0	0	0	0	0	0	1	1
70 & over	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	1	0	1	2	10	1	1	5	3	0	2	26

Average:	Age	49	Number of Participants:	Fully eligible	1	Males	22
	Service	19		Other	25	Females	4

Census data as of January 1, 2017

3.3 Age and service distribution of participating employees (Non-Administrative Medical)

Attained Age	Attained Years of Credited Service and Number													
	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	1	2	1	0	0	0	0	0	0	0	0	0	0	4
25-29	0	2	2	0	1	0	0	0	0	0	0	0	0	5
30-34	1	1	0	4	0	4	3	0	0	0	0	0	0	13
35-39	1	1	1	4	0	7	7	0	0	0	0	0	0	21
40-44	1	1	0	0	0	3	3	2	0	0	0	0	0	10
45-49	1	0	0	0	0	0	8	1	1	1	0	0	0	12
50-54	0	0	0	1	0	4	1	2	2	3	2	0	0	15
55-59	0	0	0	0	0	0	1	1	0	3	3	1	0	9
60-64	0	0	0	0	0	0	0	0	0	0	0	0	0	0
65-69	0	0	0	0	0	0	0	0	0	0	0	1	0	1
70 & over	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5	7	4	9	1	18	23	6	3	7	5	2	0	90

Average:	Age	42	Number of Participants:	Fully eligible	12	Males	83
	Service	12		Other	78	Females	7

Census data as of January 1, 2017

3.4 Age and service distribution of participating employees (Retiree Life Insurance)

Attained Age	Attained Years of Credited Service and Number													
	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	1	1	1	0	0	0	0	0	0	0	0	0	0	3
25-29	0	2	2	0	1	0	0	0	0	0	0	0	0	5
30-34	1	1	0	4	0	4	3	0	0	0	0	0	0	13
35-39	1	2	1	4	0	7	7	0	0	0	0	0	0	22
40-44	1	1	0	0	0	3	3	2	0	0	0	0	0	10
45-49	1	0	0	0	0	0	8	1	1	1	0	0	0	12
50-54	0	0	0	1	0	4	1	2	2	3	2	0	0	15
55-59	0	0	0	0	0	0	1	1	0	3	3	1	0	9
60-64	0	0	0	0	0	0	0	0	0	0	0	0	0	0
65-69	0	0	0	0	0	0	0	0	0	0	0	1	0	1
70 & over	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	5	7	4	9	1	18	23	6	3	7	5	2	0	90 [1]

Average:	Age	42	Number of Participants:	Fully eligible	12	Males	83
	Service	12		Other	78	Females	7

Census data as of January 1, 2017

[1] Ages and service totals for purposes of determining category are based on exact (not rounded) values.

Section 4: Actuarial Assumptions and Methods

All monetary amounts shown in US Dollars

Plan Name	Total Retiree Welfare	Administrative Medical	Non-Administrative Medical	Retiree Life Insurance
Fiscal Year Ending	**12/31/2016**	**12/31/2016**	**12/31/2016**	**12/31/2016**
A Assumptions				
1 Discount rate	4.10%	3.70%	4.15%	4.00%
2 Long-term rate of return on assets - VEBA	5.00%	3.35%	5.15%	5.15%
3 Long-term rate of return on assets -401(h)	5.15%	5.15%	N/A	N/A
4 Health care cost trend rates				
a Current trend rate	6.50%	6.50%	6.50%	N/A
b Ultimate trend rate	5.00%	5.00%	5.00%	N/A
c Year of ultimate trend rate	2023	2023	2023	N/A
5 Dental trend rate	5.00%	5.00%	5.00%	N/A
B Methods				
1 Asset method*	Smoothed at 20% per year	Smoothed at 20% per year	Smoothed at 20% per year	Smoothed at 20% per year
2 Amortization of gain or loss	10% corridor	10% corridor	10% corridor	10% corridor
3 Census date	1/1/2017	1/1/2017	1/1/2017	1/1/2017
*The asset smoothing method is biased				

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Appendix A - Statement of actuarial assumptions, methods and data sources

Plan Sponsor

Upper Peninsula Power Company for all plans.

Statement of Assumptions

The assumptions disclosed in this Appendix are for the fiscal year 2017 benefit cost.

Assumptions and methods for other postretirement benefit cost purposes

Actuarial Assumptions and Methods — Other Postretirement Benefit Cost	
Economic Assumptions	
Discount rate	
■ Administrative Medical and Dental Plan	3.70%
■ Non-Administrative Medical and Dental Plan	4.15%
■ Retiree Life Insurance Plan	4.00%
Expected rate of return on assets	
■ Return on Administrative VEBA	
■ Fiscal 2017	3.35%
■ Return for all other funding vehicles	
■ Fiscal 2017	5.15%

The return on assets shown above is net of investment expenses and administrative expenses assumed to be paid from the trust.

Demographic and Other Assumptions	
Inclusion date	The valuation date coincident with or next following the date on which the employee becomes a participant.
New or rehired employees	It was assumed there will be no new or rehired employees.
Covered pay	Assumed plan compensation for the year beginning on the valuation date was determined as actual gross earnings during the prior year provided by the employer

Participation Assumptions for Plan	Current Retirees	Future Retirees	
Participation:	Based on valuation census data	Percentages of eligible individuals electing coverage	
		Participant	*Spouse*
■ Medical			
■ Pre-65		100%	100%
■ Post-65		100%	100%
■ Dental			
■ Pre-65		100%	100%
■ Post-65		100%	100%
■ Life insurance		100%	100%
Percentage of retirees covering a spouse	Based on valuation census data	80% of males; 50% of females	
Spouse age	Based on valuation census data	Wife 3 years younger than husband	
Non-spouse dependent coverage	Based on valuation census data	No participants are assumed to elect coverage for non-spouse dependents in retirement.	

Demographic Assumptions

Mortality – Healthy & Disabled

RP-2014 employee and annuitant tables (no collar adjustments) adjusted backward to 2006 with MP-2014, projected forward using the MP-2015 generational improvement scale.

Disability rates

Representative Disability Rates

Percentage assumed to become disabled during the year		
Attained Age	Males	Females
20	0.030%	0.040%
25	0.030%	0.050%
30	0.040%	0.060%
35	0.050%	0.080%
40	0.070%	0.100%
45	0.100%	0.150%
50	0.180%	0.260%
55	0.360%	0.490%
60	0.900%	1.210%
65	0.000%	0.000%

Termination

Rates Varying by Age

Percentage assumed to leave during the year		
Attained Age	Males	Females
25	5.0%	10.0%
30	4.7%	9.4%
35	3.3%	6.7%
40	1.4%	2.7%
45	0.6%	1.2%
50	0.2%	0.5%
55	0.0%	0.0%
60	0.0%	0.0%

Retirement

Representative Retirement Rates

Percentage assumed to retire during the year		
Age	Administrative	Non-Administrative
55	5%	5%
56	5%	5%
57	5%	5%
58	15%	20%
59	10%	15%
60	20%	30%
61	20%	40%
62	60%	80%
63	30%	50%
64	50%	50%
65	100%	100%

Trend Rates

Health care cost trend rate:

- Medical costs for Pre-Medicare and Medicare eligible retirees: 6.50% in 2017 reducing 0.25% for 6 years, reaching 5.00% in 2023 and after
- Dental care cost trend rate: 5.00%

Participant contribution trend rates:

- Medical costs: Same as applicable medical plan trend rate
- Dental: Same as dental plan trend rate

Medicare Part D Assumptions

Eligibility for Medicare Part D subsidy: The plan for Medicare eligible participants is a Fully Insured Medicare Advantage plan.

Medicare Part D subsidy value: N/A

Per Capita Claims Costs and Retiree Contributions

Basis for per capita claim cost and retiree contribution assumptions: The average annual per capita health rates for 2017 are shown below. Best estimate assumptions developed based on insurance premiums, adjusted where appropriate for the effect of aging.

	PPO	Benistar	Dental
<50	$ 5,920	N/A	$ 413
50 – 54	$ 7,269	N/A	$ 413
55 – 59	$ 8,729	N/A	$ 413
60 – 64	$ 10,802	N/A	$ 413
65 or Older	$ 4,476	$ 5,868	$ 413

The insurance premiums for 2017 are shown below:

Age	PPO	Benistar	Dental
Prior to 65	$ 9,069	N/A	$ 413
65 or Older	$ 4,476	$ 5,868	$ 413

Methods – Other Postretirement Benefit Cost and Funded Position

Measurement date	Fiscal year-end
Service cost and accumulated postretirement benefit obligation	Costs are determined using the Projected Unit Credit Cost Method. The annual service cost is equal to the present value of the portion of the projected benefit attributable to service during the upcoming year, and the Accumulated Postretirement Benefit Obligation (APBO) is equal to the present value of the portion of the projected benefit attributable to service before the measurement date. Service from the beginning of the attribution period through the expected full eligibility date is counted in allocating costs. For Administrative employees hired prior to January 1, 2008, the beginning of the attribution period is the later of age 45 and January 1, 2013. The full eligibility date is the date the employee is eligible to retire with at least 10 years of continuous service after age 45. For Administrative employees hired on or after January 1, 2008, the beginning of the attribution period is the later of date of hire and age 45. The full eligibility date is the date the employee is eligible to retire with at least 10 years of continuous service after age 45. For the Non-Administrative plan and Retiree Life Insurance plan, the beginning of the attribution period is date of hire. The full eligibility date is age 55 with 10 years of service.
Market-related value of assets (historical accounting)	The fair value of assets on the measurement date, less the unrecognized portion of the returns net of interest and dividends on the fair value of assets. The following percentages are considered for this purpose ■ 80% of the first preceding 12 months ■ 60% of the second preceding 12 months ■ 40% of the third preceding 12 months ■ 20% of the fourth preceding 12 months The historical accounting smoothing method has a bias to produce a market-related value of assets that is below the fair value of assets.

Methods – Other Postretirement Benefit Cost and Funded Position (continued)

Amortization of unamortized amounts:

■ Transition obligation (asset)	Not applicable
■ Past service cost (credit)	Amortization of net prior service cost/(credit) resulting from a plan change is included as a component of Net Periodic Benefit Cost/(Income) in the year first recognized and every year thereafter until such time as it is fully amortized. The annual amortization payment is determined in the first year as the increase in APBO due to the plan change divided by the average remaining service period of participating employees expected to receive benefits under the plan. However, when the plan change reduces the APBO, existing positive prior service costs are reduced or eliminated on a pro-rata basis before a new prior service credit is established.
■ Net loss (gain)	Amortization of the net gain or loss resulting from experience different from the assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of Net Periodic Benefit Cost/(Income) for a year. If, as of the beginning of the year, that net gain or loss exceeds 10% of the greater of the APBO and the market-related value of assets, the amortization is that excess divided by the average remaining service period of participating employees expected to receive benefits under the plan. Under this methodology, the gain/loss amounts recognized in AOCI are not expected to be fully recognized in benefit cost until the plan is terminated (or an earlier event, like a settlement triggers recognition) because the average expected remaining service of active participants expected to benefit under the plan over which the amounts are amortized is redetermined each year and amounts that fall within the corridor described above are not amortized.
Benefits not valued	All benefits described in the Plan Provisions section of this report were valued. Willis Towers Watson has reviewed the plan provisions with the Plan Sponsor and, based on that review, is not aware of any other significant benefits required to be valued that were not.

Accounting methods	The methods used for accounting purposes as described in Appendix A, including the method of determining the market-related value of plan assets are "prescribed methods set by another party", as defined in the actuarial standards of practice (ASOPs). As required by U.S. GAAP, these methods were selected by the plan sponsor.

Assumptions Rationale - Significant Economic Assumptions

Discount rate	As required by U.S. GAAP, the discount rate was chosen by the plan sponsor based on market information on the measurement date. The rate derived from market information is rounded to 5 basis points.
Expected return on plan assets	We understand that the expected return on assets assumption reflects the plan sponsor's estimate of future experience for trust asset returns, reflecting the plan's current asset allocation and any expected changes during the current plan year, current market conditions and the plan sponsor's expectations for future market conditions. The analysis was informed by analysis of investment managers and recent trends for CPI, GDP growth, and real returns on the various classes of assets held by the trust.
Rates of increase in compensation, National Average Wages (NAW), and CPI	Assumed increases were chosen by the plan sponsor and, as required by U.S. GAAP, they represent an estimate of future experience.
Claims cost trend rates	Assumed increases were chosen by the plan sponsor and, as required by U.S. GAAP they represent an estimate of future experience, leading to select and ultimate assumed trend rates. In setting near term trend rates, other pertinent statistics were considered, including surveys on general medical cost increases. In setting the ultimate trend rate, considerations included assumed GDP growth consistent with the assumed future economic conditions inherent in other economic assumptions chosen by the client at the measurement date
Participant contribution trend rates	In accordance with the substantive plan communicated to participants, participant contributions are intended to remain a fixed percentage of total plan costs, and thus the trend rates, and the description of the derivation of the trend rates, are the same as for claims costs as shown above.

Medicare Part D subsidy trend rates	Not applicable
Per capita claims costs	Per capita claims costs were chosen by the plan sponsor based on premiums set by Blue Cross Blue Shield of Michigan and Benistar in the plan year beginning on the measurement date (with any expected changes in future years reflected in the trend rate assumption).
Medicare Part D subsidy value	Not applicable

Assumptions Rationale - Significant Demographic Assumptions

Healthy Mortality	Assumptions used for accounting purposes were selected by the plan sponsor and, as required by U.S. GAAP, represent a best estimate of future experience.
Disabled Mortality	Assumptions used for accounting purposes were selected by the plan sponsor and, as required by U.S. GAAP, represents a best estimate of future experience.
Termination	Termination rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual termination experience different than expected.
Disability	Disability rates are based on a standard UAW table. Actual experience is not credible to set plan specific rates.
Retirement	Retirement rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual retirement experience different than expected.
Participation:	
Participants	Assumed participation rates reflect historical experience as well as anticipated future experience.
Covered spouses	Assumed coverage rates for spouses reflect historical experience as well as anticipated future experience.

Benefit commencement date:

Retiree benefit	Retirees are assumed to begin benefits immediately on eligible retirement because experience shows that retirees who enroll tend to do so immediately.

Marital Assumptions:

Percent married	The assumed percentage married is based on general population statistics on the marital status of individuals of retirement age.
Spouse age	The assumed age difference for spouses is based on general population statistics of the age difference for married individuals of retirement age.

Data Sources

The plan sponsor furnished participant data and claims data as of 1/1/2017. Information on assets, contributions and plan provisions was supplied by the plan sponsor. Data and other information were reviewed for reasonableness and consistency, but no audit was performed. Based on discussions with the plan sponsor, assumptions or estimates were made when data were not available, and the data was adjusted to reflect any significant events that occurred between the date the data was collected and the measurement date. In consultations with the Company, the following assumptions were made for missing or apparently inconsistent data elements: for missing beneficiary dates of birth, females were assumed to be 3 years younger than males; for missing beneficiary sexes, male participants were assumed to have a female beneficiary and female participants were assumed to have a male beneficiary.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Changes in Assumptions and Methods

There are no changes in assumptions and methods since the year-end 2016 disclosure report.

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Appendix B - Summary of principal other postretirement benefit plan provisions

Substantive Plan Provisions – UPPCO Administrative Retiree, LTD and Surviving Spouse Medical & Dental

Medical Benefits

Eligibility

Employees who retire prior to January 1, 2013 are eligible upon retirement and attaining age 55 and 5 years of service.

All other employees who are hired prior to August 28, 2014 are eligible upon retirement and completion of 10 years of service after attaining age 45.

Employees hired on or after August 28, 2014 are not eligible for coverage.

Anyone that is promoted from a union to non-union position after August 28, 2016 is not eligible for medical benefits.

Medical benefit

Post January 1, 2013 retirees

Employees who retire after January 1, 2013 will receive a $4,000 retiree medical contribution credit (RMCC) for each year of service earned after the later of age 45 and January 1, 2013. RMCC are used to offset the premiums of company-sponsored health plans in retirement.

Pre January 1, 2013 retirees

Employees who retired prior to January 1, 2001 pay 50% of benefit cost. Employees who retire on or after January 1, 2001 pay the full cost for their retiree medical.

A grandfathered group of participants participate in a Medigap plan sponsored by Benistar.

Retiree contributions

Refer to Methods and Assumptions for the premiums paid

Deductible

	In-Network	Out-of-Network
PPO (single/family)	$1,300/$2,600	$2,600/$5,200
MAPD PPO (per individual)	$500	$500

Coinsurance

	In-Network	Out-of-Network
PPO	80%	60%
MAPD PPO	80%	60%

Out-of-pocket maximum (includes deductible)

	In-Network	Out-of-Network
PPO (single/family)	$2,250/$4,500	$4,500/$9,000
MAPD PPO (per individual)	$2,000	$2,500

Prescription drug copayments

		Generic	Brand	Non-Preferred	Specialty Drugs
Retail:					
	PPO	$10.00	$60.00	$60.00	N/A
	MAPD PPO	$5.00	$30.00	$30.00	$60.00
Mail Order:					
	PPO	$20.00	$120.00	$120.00	N/A
	MAPD PPO	$10.00	$60.00	$60.00	N/A

Lifetime benefit maximum Unlimited

Dental Benefits

Eligibility

Employees who retire prior to January 1, 2013 are eligible upon retirement and attaining age 55 and 5 years of service.

All other employees retiring on or after January 1, 2013 will not be eligible for retiree dental benefits.

Benefits

Employees who retired before January 1, 2001 do not receive a dental benefit. Those who retire after January 1, 2001 pay the full cost.

Retiree contributions

Refer to methods and assumptions

Deductible

$50 per person/$150 per family

Annual maximum

$1,500 per participant

Coverage

Preventative care services: Covered at 100%; no deductible

Basic services: Covered at 80%; after deductible

Major services: Covered at 50% after deductible

Orthodontia services (for dependent children under age 19 only):

- Covered at 50% after deductible
- Lifetime maximum of $2,000

Changes in Benefits Valued

There are no changes in benefits valued since the year-end 2016 disclosure report.

Substantive Plan Provisions – UPPCO Non-Administrative Retiree, LTD and Surviving Spouse Medical & Dental

Medical Benefits

Eligibility

Age 55 and 10 years of service, or 85 points.

Medical benefit

Employees receive fully subsidized benefits for a period of 3 years (or until age 65, if earlier), after which employees pay 50% of benefit cost (for all covered persons). A covered spouse of a retiree who dies is required to pay 50% of benefit cost following the death of the retiree.

A grandfathered group of participants participate in a Medigap plan sponsored by Benistar.

Former UPPCO term vested employees who were "grandfathered" continue accruing age plus service toward 85 points, and may have access to UPPCO retiree coverage when they reach 85 points and begin drawing their UPPCO pension benefit. A "Grandfathered" employee is someone who was employed by UPPCO on January 1, 1994 and whose combined age and years of service total 55 or more.

Retiree contributions

Refer to Methods and Assumptions for the premiums paid

Deductible

	In-Network	Out-of-Network
PPO (single/family)	$1,300/$2,600	$2,600/$5,200
MAPD PPO (per individual)	$500	$500

Coinsurance

	In-Network	Out-of-Network
PPO	80%	60%
MAPD PPO	80%	60%

Out-of-pocket maximum (includes deductible)

	In-Network	Out-of-Network
PPO (single/family)	$2,250/$4,500	$4,500/$9,000
MAPD PPO (per individual)	$2,000	$2,500

Prescription drug copayments

		Generic	Brand	Non-Preferred	Specialty Drugs
Retail:					
	PPO	$10.00	$60.00	$60.00	N/A
	MAPD PPO	$5.00	$30.00	$30.00	$60.00
Mail Order:		Generic	Brand	Non-Preferred	
	PPO	$20.00	$120.00	$120.00	N/A
	MAPD PPO	$10.00	$60.00	$60.00	N/A

Lifetime benefit maximum Unlimited

Dental Benefits

Eligibility Age 55 and 10 years of service, or 85 points.

Retiree contributions Refer to methods and assumptions

Deductible $50 per person/$150 per family

Annual maximum $1,500 per participant

Coverage Preventative care services: Covered at 100%; no deductible

Basic services: Covered at 80%; after deductible

Major services: Covered at 50% after deductible

Orthodontia services (for dependent children under age 19 only):

- Covered at 50% after deductible
- Lifetime maximum of $2,000

Changes in Benefits Valued

There are no changes in benefits valued since the year-end 2016 disclosure report.

Substantive Plan Provisions – UPPCO Postretirement Life Insurance and Survivor Income Benefit

Life Insurance Benefits

Eligibility

Non-Administrative

Age 55 and 10 years of service, or 85 points.

Administrative

Age 55 and 5 years of service for employees hired on or before December 31, 2000 who retire prior to January 1, 2013.

Benefit

Non-Administrative

Employees Group Life-Company Paid

Benefits into retirement if:

- Insured for a minimum of 10 years.

Benefit amount into retirement:

- Benefit amount is 1.5 times salary. If benefit is greater than $50,000 at retirement, benefit is reduced to $50,000 less 15% and will be reduced by the same 15% on the next four retirement anniversary years, but in no case will the amount be less than $15,000.
- If benefit is $50,000 or less at retirement, benefit is reduced by 15% and will be reduced by the same 15% on the next four retirement anniversary years, but in no case will the amount be less than $15,000.

UPPCO terminated vested and Presque Isle grandfathered participants are generally not eligible for retiree life insurance.

Administrative Employees

Life Insurance – $7,000 Non-Contributory Life Insurance for employees hired on or before December 31, 2000. Employees retiring on or after January 1, 2013 will not be eligible for life insurance.

Some UPPCO Grandfathered retirees have a different life insurance amount that varies by individual.

Changes in Benefits Valued

There are no changes in benefits valued since the year-end 2016 disclosure report.

WillisTowersWatson

Upper Peninsula Power Company

Consolidated Pension Plan Actuarial Valuation Report Benefit Cost for Fiscal Year Beginning January 1, 2017 under US GAAP

August 2017

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Purposes of valuation

Upper Peninsula Power Company engaged Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC ("Willis Towers Watson") to value the Company's pension plans.

As requested by Upper Peninsula Power Company (the Company), this report documents the results of an actuarial valuation of the Plans:

- Upper Peninsula Power Company Retirement Plan
- Upper Peninsula Power Company Pension Restoration Plan
- Upper Peninsula Power Company SERP

The primary purpose of this valuation is to determine the Net Periodic Benefit Cost/(Income) (Benefit Cost), in accordance with FASB Accounting Standards Codification Topic 715 (ASC 715) for the fiscal year beginning January 1, 2017. It is anticipated that a separate report will be prepared for year-end financial reporting purposes.

Limitations

This valuation has been conducted for the purposes described above and may not be suitable for any other purpose. In particular, please note the following:

1. The expected contributions to the qualified pension plan(s) were set at $0

   Note that any significant change in the amounts contributed or expected to be contributed in 2017 will require disclosure in the interim financial statements, but should not affect the expected return on plan assets absent a remeasurement for another purpose.

2. There may be certain events that have occurred since the valuation date that are not reflected in the current valuation. See Subsequent Events in the Basis for Valuation section below for more information.

3. This report is not intended to constitute a certification of the Adjusted Funding Target Attainment Percentage (AFTAP) under IRC §436 for any plan year.

4. This report does not determine funding requirements under IRC §430.

5. This report does not provide information for plan reporting under ASC 960.

6. This report does not determine liabilities on a plan termination basis, for which a separate extensive analysis would be required. No funded status measure included in this report is intended to assess, and none may be appropriate for assessing, the sufficiency of plan assets to cover the estimated cost of settling benefit obligations, as all such measures differ in some way from plan termination obligations. In addition, funded status measures shown in this report do not reflect the current costs of settling obligations by offering immediate lump sum payments to participants and/or purchasing annuity contracts for the remaining participants (e.g., insurer profit, insurer pricing of contingent benefits and/or provision for anti-selection in the choice of a lump sum vs. an annuity).

7. The comparisons of accounting obligations to assets presented in this report cannot be relied upon to determine the need for nor the amount of required future plan contributions. Nevertheless, such comparisons may be useful to assess the need for future contributions because they reflect current interest rates at the measurement date in determining benefit obligations. However, asset gains and losses, demographic experience different from assumed, changes in interest rates, future benefit accruals, if any, and other factors will all affect the need for and amount of future contributions. In addition, if a plan is not required by law to be funded, benefit payments may also be paid directly by the plan sponsor as they come due.

Section 1: Summary of key results

Benefit cost, assets & obligations

All monetary amounts shown in US Dollars

Plan Name		Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Fiscal Year Beginning		01/01/2017	01/01/2017	01/01/2017	01/01/2017
Benefit Cost/ (Income)	Net Periodic Benefit Cost/(Income)	1,310,403	1,244,121	48,800	17,482
	Immediate Recognition of Benefit Cost/(Income) due to Special Events	0	0	0	0
	Total Benefit Cost/(Income)	1,310,403	1,244,121	48,800	17,482
Measurement Date		01/01/2017	01/01/2017	01/01/2017	01/01/2017
Plan Assets	Fair Value of Assets (FVA)	109,087,777	109,087,777	0	0
	Market Related Value of Assets (MRVA)	113,674,072	113,674,072	0	0
	Return on Fair Value Assets during Prior Year	4.72%	4.72%	N/A	N/A
Benefit Obligations	Accumulated Benefit Obligation (ABO)	(108,580,706)	(107,972,966)	(417,639)	(190,101)
	Projected Benefit Obligation (PBO)	(111,603,212)	(110,995,472)	(417,639)	(190,101)
Funded Ratios	Fair Value of Assets to ABO	100.5%	101.0%	0.0%	0.0%
	Fair Value of Assets to PBO	97.7%	98.3%	0.0%	0.0%
Accumulated Other Comprehensive (Income)/Loss	Net Prior Service Cost/(Credit)	0	0	0	0
	Net Loss/(Gain)	60,951,566	60,575,465	232,763	143,338
	Total Accumulated Other Comprehensive (Income)/Loss	60,951,566	60,575,465	232,763	143,338
Assumptions	Discount Rate	3.95%	3.95%	3.80%	3.55%
	Expected Long-term Rate of Return on Plan Assets	5.15%	5.15%	N/A	N/A
	Rate of Compensation Increase (administrative/ non-administrative)	4.50%/4.00%	4.50%/4.00%	4.50%	N/A
Participant Data	Census Date	01/01/2017	01/01/2017	01/01/2017	01/01/2017

Comments on results

The consolidated actuarial gains/(losses) due to demographic experience, including any assumption changes, and investment return different from assumed during the prior year were $(2,363,255) and $(652,746) respectively.

Change in net periodic cost and funded position

The net periodic cost declined from $1,379,243 in fiscal 2016 to $1,310,403 in fiscal 2017 and the funded position declined from $17,426 to $(2,515,435).

Significant reasons for these changes include the following:

- The return on the fair value of plan assets since the prior measurement date was less than expected, which caused the funded position to deteriorate.
- The discount rate decrease compared to the prior year, which reduced the net periodic cost and caused the funded position to deteriorate.

Basis for valuation

Appendix A summarizes the assumptions and methods used in the valuation. Appendix B summarizes our understanding of the principal provisions of the plan being valued. Unless otherwise described below under Subsequent Events, assumptions were selected based on information known as of the measurement date.

The results reflect Historical Accounting (i.e., no purchase accounting at August 28, 2014).

Changes in assumptions

There were no changes in assumptions from the year-end 2016 disclosure report.

Changes in methods

There were no changes in assumptions from the year-end 2016 disclosure report.

Changes in benefits valued

There were no changes in benefits valued from the year-end 2016 disclosure report.

Subsequent events

There were no subsequent events to those included in the year-end 2016 disclosure report.

Actuarial certification

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. However, please note the information discussed below regarding this valuation.

Reliances

In preparing the results presented in this report, we have relied upon information regarding plan provisions, participants, assets, and sponsor accounting policies and methods provided by the Company and other persons or organizations designated by the Company. See the Data Sources section of Appendix A for further details. We have relied on all the data and information provided as complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations. The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, assets, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies, as corrected by the Company, may produce materially different results that could require that a revised report be issued.

Measurement of benefit obligations, plan assets and balance sheet adjustments

Census date/measurement date

The measurement date is January 1, 2017. The benefit obligations were measured as of January 1, 2017 and are based on participant data as of the census date, January 1, 2017.

Plan assets and balance sheet adjustments

Information about the fair value of plan assets was furnished to us by the Company. The Company also provided information about the general ledger account balances for the pension plan cost at December 31, 2016, which reflect the expected funded status of the plans before adjustment to reflect the funded status based on the year-end measurements. Willis Towers Watson used information supplied by the Company regarding amounts recognized in accumulated other comprehensive income as of December 31, 2016. This data was reviewed for reasonableness and consistency, but no audit was performed.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for tax effects. Any tax effects in AOCI should be determined in consultation with the Company's tax advisors and auditors.

Assumptions and methods under U.S. GAAP

As required by U.S. GAAP, the actuarial assumptions and methods employed in the development of the pension cost and other financial reporting have been selected by the Company. Willis Towers Watson has concurred with these assumptions and methods. U.S. GAAP requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this report have been developed based on actuarial assumptions that, to the extent evaluated by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

A summary of the assumptions and methods used is provided in Appendix A. Note that any subsequent changes in methods or assumptions for the January 1, 2017 measurement date will change the results shown in this report.

Nature of actuarial calculations

The results shown in this report are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. The effects of certain plan provisions may be approximated, or determined to be insignificant and therefore not valued. Reasonable efforts were made in preparing this valuation to confirm that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and are not excluded or included inappropriately. Any rounding (or lack thereof) used for displaying numbers in this report is not intended to imply a degree of precision, which is not a characteristic of actuarial calculations.

If overall future plan experience produces higher benefit payments or lower investment returns than assumed, the relative level of plan costs reported in this valuation will likely increase in future valuations (and vice versa). Future actuarial measurements may differ significantly from the current measurements presented in this report due to many factors, including: plan experience differing from that anticipated by the economic or demographic assumptions, changes in economic or demographic assumptions, increases or decreases expected as part of the natural operation of the methodology used for the measurements (such as the end of an amortization period), and changes in plan provisions or applicable law. Due to the limited scope of our assignment, we did not perform an analysis of the potential range of such future measurements.

See Basis for Valuation in Section 1 above for a discussion of any material events that have occurred after the valuation date that are not reflected in this valuation.

Limitations on use

This report is provided subject to the terms set out herein and in our engagement letter dated April 8, 2014 and any accompanying or referenced terms and conditions.

The information contained in this report was prepared for the internal use of the Company and its auditors in connection with our actuarial valuation of the pension plan as described in Purposes of Valuation above. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard. The Company may distribute this actuarial valuation report to the appropriate authorities who have the legal right to require the Company to provide them this report, in which case the Company will use best efforts to notify Willis Towers Watson in advance of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

Professional qualifications

The undersigned are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc., a subsidiary of Willis Towers Watson PLC ("Willis Towers Watson").

Georgia Louridas, FSA, EA
Senior Consulting Actuary
8/17/2017

Steven James, FSA, EA
Senior Consulting Actuary
8/17/2017

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Section 2: Accounting exhibits

2.1 Balance sheet asset/(liability)

All monetary amounts shown in US Dollars

	Plan Name	Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
	Measurement Date	01/01/2017	01/01/2017	01/01/2017	01/01/2017
A	**Development of Balance Sheet Asset/(Liability)**[1]				
	1 Projected benefit obligation (PBO)	(111,603,212)	(110,995,472)	(417,639)	(190,101)
	2 Fair value of assets (FVA)[2]	109,087,777	109,087,777	0	0
	3 Net balance sheet asset/(liability)	(2,515,435)	(1,907,695)	(417,639)	(190,101)
B	**Current and Noncurrent Allocation**[3]				
	1 Noncurrent asset	0	0	0	0
	2 Current liability	(51,357)	0	(28,865)	(22,492)
	3 Noncurrent liability	(2,464,078)	(1,907,695)	(388,774)	(167,609)
	4 Net balance sheet asset/(liability)	(2,515,435)	(1,907,695)	(417,639)	(190,101)
C	**Accumulated Benefit Obligation (ABO)**	(108,580,706)	(107,972,966)	(417,639)	(190,101)
D	**Accumulated Other Comprehensive (Income)/Loss**				
	1 Net prior service cost/(credit)	0	0	0	0
	2 Net loss/(gain)	60,951,566	60,575,465	232,763	143,338
	3 Accumulated other comprehensive (income)/loss[4]	60,951,566	60,575,465	232,763	143,338
E	**Assumptions and Dates**				
	1 Discount rate	3.95%	3.95%	3.80%	3.55%
	2 Rate of Compensation Increase (administrative/ non-administrative)	4.50%/4.00%	4.50%/4.00%	4.50%	0.00%
	3 Census date	01/01/2017	01/01/2017	01/01/2017	01/01/2017

1 Whether the amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.
2 Excludes receivable contributions.
3 The current liability (for each underfunded plan) was measured as the discounted value of benefits expected to be paid over the next 12 months in excess of the fair value of the plan's assets at the measurement date.
4 Amount shown is pre-tax and should be adjusted by plan sponsor for tax effects.

2.2 Changes in liabilities and assets

All monetary amounts shown in US Dollars

Plan Name	Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Fiscal Year Beginning	01/01/2017	01/01/2017	01/01/2017	01/01/2017
A Change in Projected Benefit Obligation (PBO)				
1 PBO at beginning of prior fiscal year	111,011,649	110,367,466	427,291	216,892
2 Employer service cost	825,189	825,189	0	0
3 Interest cost	4,477,410	4,453,879	16,304	7,227
4 Actuarial loss/(gain)	2,363,255	2,361,249	3,327	(1,321)
5 Plan participants' contributions	0	0	0	0
6 Benefits paid from plan assets	(7,074,291)	(7,012,311)	(29,283)	(32,697)
7 Benefits paid from the Company	0	0	0	0
8 Administrative expenses paid[1]	0	0	0	0
9 Plan change	0	0	0	0
10 Acquisitions/(divestitures)	0	0	0	0
11 Curtailments	0	0	0	0
12 Settlements	0	0	0	0
13 Special/contractual termination benefits	0	0	0	0
14 PBO at beginning of current fiscal year	111,603,212	110,995,472	417,639	190,101
B Change in Plan Assets				
1 Fair value of assets at beginning of prior fiscal year	111,029,075	111,029,075	0	0
2 Actual return on assets	5,071,013	5,071,013	0	0
3 Employer contributions	61,980	0	29,283	32,697
4 Plan participants' contributions	0	0	0	0
5 Benefits paid	(7,074,291)	(7,012,311)	(29,283)	(32,697)
6 Administrative expenses paid	0	0	0	0
7 Transfer payments	0	0	0	0
8 Acquisitions/(divestitures)	0	0	0	0
9 Settlements	0	0	0	0
10 Fair value of assets at beginning of current fiscal year	109,087,777	109,087,777	0	0

1 Only if future expenses are accrued in PBO through a load on service cost.

2.3 Summary of net balances

All monetary amounts shown in US Dollars

Plan Name	Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Fiscal Year Beginning	01/01/2017	01/01/2017	01/01/2017	01/01/2017
A Summary of Net Prior Service Cost/(Credit)				
1 Net amount at current fiscal year begin	0	0	0	0
2 Amortization amount during current fiscal year	0	0	0	0
3 Plan changes	0	0	0	0
4 Effect of curtailments	0	0	0	0
5 Other events	0	0	0	0
B Summary of Net Loss/(Gain)				
1 Net amount at current fiscal year begin	60,951,566	60,575,465	232,763	143,338
2 Amortization amount during current fiscal year	(1,829,490)	(1,784,871)	(33,483)	(11,136)
3 Experience loss/(gain)	N/A	N/A	N/A	N/A
4 Effect of curtailments	0	0	0	0
5 Effect of settlements	0	0	0	0
6 Amortization Period	N/A	25.0000	5.70436	11.16467

2.4 Development of assets for benefit cost

All monetary amounts shown in US Dollars

Plan Name	Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Fiscal Year Ending	12/31/2016	12/31/2016	12/31/2016	12/31/2016
A Development of Market-Related Value of Assets				
1 Fair value of assets at current fiscal year end	109,087,777	109,087,777	N/A	N/A
2 Deferred investment gains/(losses) for prior periods				
Fiscal Year Gain/(Loss)				
a 12/31/2016	(652,746)	(652,746)	N/A	N/A
b 12/31/2015	(6,741,227)	(6,741,227)	N/A	N/A
c 12/31/2014	(3,156,625)	(3,156,625)	N/A	N/A
d 12/31/2013	6,216,437	6,216,437	N/A	N/A
e 12/31/2012	(4,137,830)	(4,137,830)	N/A	N/A
Percent Deferred				
a 12/31/2016	80%	80%	N/A	N/A
b 12/31/2015	60%	60%	N/A	N/A
c 12/31/2014	40%	40%	N/A	N/A
d 12/31/2013	20%	20%	N/A	N/A
e 12/31/2012	0	0	N/A	N/A
Deferred Amount				
a 12/31/2016	(522,196)	(522,196)	N/A	N/A
b 12/31/2015	(4,044,736)	(4,044,736)	N/A	N/A
c 12/31/2014	(1,262,650)	(1,262,650)	N/A	N/A
d 12/31/2013	1,243,287	1,243,287	N/A	N/A
e 12/31/2012	0	0	N/A	N/A
3 Market-related value of assets	113,674,072	113,674,072	N/A	N/A

2.5 Summary and comparison of benefit cost and cash flows

All monetary amounts shown in US Dollars

Plan Name	Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Fiscal Year Ending	12/31/2017	12/31/2017	12/31/2017	12/31/2017
A Total Benefit Cost				
1 Employer service cost	847,935	847,935	0	0
2 Interest cost	4,280,438	4,258,775	15,317	6,346
3 Expected return on assets	(5,647,460)	(5,647,460)	0	0
4 Subtotal	(519,087)	(540,750)	15,317	6,346
5 Net prior service cost/(credit) amortization	0	0	0	0
6 Net loss/(gain) amortization	1,829,490	1,784,871	33,483	11,136
7 Subtotal	1,829,490	1,784,871	33,483	11,136
8 Net periodic benefit cost/(income)	1,310,403	1,244,121	48,800	17,482
9 Curtailments	0	0	0	0
10 Settlements	0	0	0	0
11 Special/contractual termination benefits	0	0	0	0
12 Total benefit cost	1,310,403	1,244,121	48,800	17,482
B Assumptions[1]				
1 Discount rate	3.95%	3.95%	3.80%	3.55%
2 Rate of return on assets	5.15%	5.15%	N/A	N/A
3 Rate of compensation increase (administrative/ non-administrative)	4.50%/4.00%	4.50%/4.00%	4.50%	0.00%
4 Pension increases for in-payment benefits	0.00%	0.00%	0.00%	0.00%
5 Pension increases for deferred benefits	0.00%	0.00%	0.00%	0.00%
6 Census date	01/01/2017	01/01/2017	01/01/2017	01/01/2017
C Assets at Beginning of Year				
1 Fair market value	109,087,777	109,087,777	0	0
2 Market-related value	113,674,072	113,674,072	0	0
D Cash Flow				
i Expected				
1 Employer contributions	0	0	0	0
2 Plan participants' contributions[2]	0	0	0	0
3 Benefits paid from the Company	52,296	0	29,408	22,888
4 Benefits paid from plan assets[2]	8,131,374	8,131,374	0	0

1 These assumptions were used to calculate Net Periodic Benefit Cost/(Income) as of the beginning of the year. Rates are expressed on an annual basis where applicable. For assumptions used for interim measurement periods, if any, refer to Appendix A.
2 Over the fiscal year.

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Section 3 Data exhibits

3.1 Plan participant data

All monetary amounts shown in US Dollars

Plan Name		Total Pension	UPPCO Retirement Plan	UPPCO Restoration Plan	UPPCO SERP
Measurement Date		01/01/2017	01/01/2017	01/01/2017	01/01/2017
Census Date		N/A	01/01/2017	01/01/2017	01/01/2017
Participating Employees	Number	82	82	1	0
	Average Annual Plan Compensation/Salary (limited)	93,766	93,766	236,344	0
	Average Age	47.04	47.04	55.00	0.00
	Average Credited Service	18.07	18.07	31.81	0.00
Participants with Deferred Benefits	Number	71	71	0	0
	Average Annual Deferred Benefits	6,693	6,693	0	0.00
Participants Receiving Benefits	Number	528	524	2	3
	Average Annual Benefit Payments	12,381	12,367	14,642	7,671
Other Participants	Number	0	0	0	0
	Average Annual Benefit Payments	N/A	N/A	N/A	N/A

3.2 Age and service distribution of participating employees (Retirement Plan)

All monetary amounts shown in US Dollars

Attained Age	Attained Years of Credited Service and Number and Average Compensation													
	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25-29	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30-34	0	0	0	0	0	4	3	0	0	0	0	0	0	7
35-39	0	0	0	0	0	5	11	0	0	0	0	0	0	16
40-44	0	0	0	0	0	1	4	2	0	0	0	0	0	7
45-49	0	0	0	0	0	0	13	2	1	2	0	0	0	18
50-54	0	0	0	0	0	2	1	3	2	6	4	0	0	18
55-59	0	0	0	0	0	0	2	1	1	4	4	2	0	14
60-64	0	0	0	0	0	0	0	0	0	0	0	0	1	1
65-69	0	0	0	0	0	0	0	0	0	0	0	0	1	1
70 & over	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	12	34	8	4	12	8	2	2	82
Average Pay							88,771							93,766

Average:	Age	47	Number of Participants:	Fully vested	82	Males	76
	Service	18		Partially vested	0	Females	6

Census data as of January 1, 2017

Appendix A- Statement of consolidated actuarial assumptions and methods

Plan Sponsor

Upper Peninsula Power Company for all plans.

Statement of Assumptions

The assumptions disclosed in this Appendix are for the fiscal year 2017 benefit cost.

Assumptions and methods for pension cost purposes

Economic Assumptions	
Discount rate:	
■ Upper Peninsula Power Company Retirement Plan	3.95%
■ Pension Restoration Plan	3.80%
■ SERP	3.55%
Expected return on assets	
■ Fiscal 2017	5.15%
Lump sum conversion rate	
■ Upper Peninsula Power Company Retirement Plan	3.95%
Annual rates of increase	
■ Compensation:	
■ Administrative employees	4.50%
■ Non-Administrative employees	4.00%
■ Future Social Security wage bases	3.50%
■ Statutory limits on compensation	2.50%
■ Interest crediting rate	3.05%

The expected return on assets shown above is net of expenses assumed to be paid from the trust.

Demographic and Other Assumptions

Inclusion date — The valuation date coincident with or next following the date on which the employee becomes a participant.

New or rehired employees — It was assumed there will be no new or rehired employees.

Benefit commencement dates

- Preretirement death benefit
  - Administrative — Upon death of the active participant
  - Non-Administrative — Upon the later of the death of the active participant or the date the participant would have attained earliest retirement age.
- Deferred vested benefit
  - Administrative — Upon termination of employment
  - Non-Administrative — Upon the later of attainment of normal retirement age or termination of employment.
- Disability benefit — Upon disablement
- Retirement benefit — Upon termination of employment

Form of payment

- Administrative — 100% of participants are assumed to elect an immediate lump sum.
- Non-Administrative — 100% of single participants are assumed to elect a lifetime monthly annuity. 100% of married participants assumed to elect a 50% Joint and Survivor annuity.

Mortality for annuity conversion basis for PEP account balances and lump sums	417(e)(3) applicable mortality table
Percent married	80% of males; 50% of females
Spouse age	Wife three years younger than husband
Cash flow	
■ Timing of benefit payments	Annuity payments are payable monthly at the beginning of the month and lump sum payments are payable on date of decrement.

Demographic Assumptions

Mortality – Healthy & Disabled	RP-2014 employee and annuitant tables (no collar adjustments) adjusted backward to 2006 with scale MP-2014 and projected forward generationally from 2006 with scale MP-2015.
Disability	Rates Varying by Age and Gender Representative Disability Rates

Percentage assumed to become disabled during the year		
Attained Age	Males	Females
20	0.030%	0.040%
25	0.030%	0.050%
30	0.040%	0.060%
35	0.050%	0.080%
40	0.070%	0.100%
45	0.100%	0.150%
50	0.180%	0.260%
55	0.360%	0.490%
60	0.900%	1.210%
65	0.000%	0.000%

Termination

Rates Varying by Age and Gender
Representative Termination Rates

Percentage assumed to leave during the year		
Attained Age	Males	Females
25	5.0%	10.0%
30	4.7%	9.4%
35	3.3%	6.7%
40	1.4%	2.7%
45	0.6%	1.2%
50	0.2%	0.5%
55	0.0%	0.0%
60	0.0%	0.0%

Retirement

Rates Varying by Age and Plan
Representative Retirement Rates

Percentage assumed to retire during the year		
Age	Administrative	Non-Administrative
55	5%	5%
56	5%	5%
57	5%	5%
58	15%	20%
59	10%	15%
60	20%	30%
61	20%	40%
62	60%	80%
63	30%	50%
64	50%	50%
65	100%	100%

Methods (for all plans)

Measurement date

Fiscal year-end

Service cost and projected benefit obligation

The Projected Unit Credit Cost Method is used to determine the Projected Benefit Obligation (PBO) and the related service cost. Under this method, a "projected accrued benefit" is calculated based upon service as of the measurement date and projected future compensation and social security levels at the age at which the employee is assumed to leave active service. The PBO is the present value of this benefit and the service cost is the present value of the increase in the benefit due to service in the upcoming year. In normal circumstances the "projected accrued benefit" is based upon the plan's accrual formula. However, if service in later years leads to a materially higher level of benefit than in earlier years, the "projected accrued benefit" is calculated by attributing benefits on a straight-line basis over the relevant period.

The benefits described above are used to determine both ABO and PBO (except that final average pay, Social Security offsets, and covered compensation are assumed to remain constant in the future when calculating ABO).

Market value of assets

The fair value of assets on the measurement date, less the unrecognized portion of assets gains and losses on fair value of assets. The following percentages are considered for this purpose

- 80% of the first preceding 12 months
- 60% of the second preceding 12 months
- 40% of the third preceding 12 months
- 20% of the fourth preceding 12 months

Amortization of unamortized amounts:

- Transition obligation (asset)

Not applicable

- Past service cost (credit)

Amortization of net prior service cost/(credit) resulting from a plan change is included as a component of Net Periodic Benefit Cost/(Income) in the year first recognized and every year thereafter until such time as it is fully amortized. The annual amortization payment is determined in the first year as the increase in PBO due to the plan change divided by the average remaining service period of participating employees expected to receive benefits under the plan.

However, when the plan change reduces the PBO, existing positive prior service costs are reduced or eliminated on a pro-rata basis before a new prior service credit is established.

- Net loss (gain)

Amortization of the net gain or loss resulting from experience different from the assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of Net Periodic Benefit Cost/(Income) for a year.

If, as of the beginning of the year, that net gain or loss exceeds 10% or greater of the PBO and the market-related value of assets, the amortization is that excess divided by 25 years for the qualified plan and average remaining life expectancy for the non-qualified plans.

The plan sponsor considers participants whose benefits are soft frozen to be active participants.

Under this methodology, the gain/loss amount recognized in AOCI are not expected to be fully recognized in benefit cost until the plan is terminated (or an earlier event, like a settlement triggers recognition) because the period over which the amounts are amortized is redetermined each year and amounts that fall within the corridor described above are not amortized.

Benefits not valued

All benefits described in the Plan Provisions were valued as described. Willis Towers Watson is not aware of any significant benefits required to be valued that were not.

Accounting methods

The methods used for accounting purposes described in Appendix A, including the method of determining the market-related value of plan assets are "prescribed methods set by another party," as defined in the actuarial standards of practice (ASOPs). As required by U.S. GAAP, these methods were selected by the plan sponsor.

Assumptions Rationale - Significant Economic Assumptions

Discount rate	As required by U.S. GAAP the discount rate was chosen by the plan sponsor based on market information on the measurement date. The rate derived from market information is rounded to 5 basis points.
Expected return on plan assets	We understand that the expected return on assets assumption reflects the plan sponsor's estimate of future experience for trust asset returns, reflecting the plan's current asset allocation and any expected changes during the current plan year, current market conditions and the plan sponsor's expectations for future market conditions. The analysis was informed by analysis of historical data and recent trends for CPI, GDP growth, and real returns on the various classes of assets held by the trust.
Interest crediting rate	The plan will credit interest to the frozen pension equity plan accounts using the first segment rate defined under the Pension Protection Act for use in determining minimum lump distribution under IRC 417(e)(3). The plan sponsor has selected a single rate. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Annuity conversion rate	The annuity conversion rate is based on the current market rates. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Lump sum conversion rate	Lump sum benefits are valued based on the current market rates. After examining historical variability in this rate, we believe that the selected assumption does not significantly conflict with what would be reasonable based on a combination of market conditions at the measurement date and future expectations consistent with other economic assumptions used.
Rates of increase in compensation, National Average Wages (NAW), and CPI	Assumed increases were chosen by the plan sponsor and, as required by U.S. GAAP they represent an estimate of future experience.
Administrative expenses	Administrative expenses are estimated by determining the actual expenses paid from the trust the preceding year and are already incorporated into the expected rate on assets assumption.

Assumptions Rationale - Significant Demographic Assumptions

Healthy Mortality	Assumptions used for accounting purposes were selected by the plan sponsor and, as required by U.S. GAAP, represent a best estimate of future experience.
Disabled Mortality	Assumptions used for accounting purposes were selected by the plan sponsor and, as required by U.S. GAAP, represent a best estimate of future experience.
Termination	Termination rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual termination experience different than expected.
Disability	Disability rates are based on a standard UAW table. Actual experience is not material to set plan-specific rates.
Retirement	Retirement rates were set several years ago based on historical experience and no significant gains or losses have been observed due to actual retirement experience different than expected.
Benefit commencement date for deferred benefits:	
■ Deferred vested benefit	Deferred vested participants are assumed to begin benefits at age 65 (or current age if later) because the plan's experience is not considered to be credible.
Form of payment	Retiring Administrative participants are assumed to take a lump sum due to the design of the plan. Retiring Non-Administrative participants are assumed to take a 50% joint and survivor annuity if married and a single life annuity if single. These are the normal forms under the plan.
Marital Assumptions:	
■ Percent married	The assumed percentage married is based on general population statistics on the marital status of individuals of retirement age.
■ Spouse age	The assumed age difference for spouses is based on general population statistics of the age difference for married individuals of retirement age.

Data Sources

The plan sponsor furnished participant data and claims data as of 1/1/2017. Information on assets, contributions and plan provisions was supplied by the plan sponsor. Data and other information were reviewed for reasonableness and consistency, but no audit was performed. Based on discussions with the plan sponsor, assumptions or estimates were made when data were not available, and the data was adjusted to reflect any significant events that occurred between the date the data was collected and the measurement date. In consultations with the Company, the following assumptions were made for missing or apparently inconsistent data elements: for missing beneficiary dates of birth, females were assumed to be 3 years younger than males; for missing beneficiary sexes, male participants were assumed to have a female beneficiary and female participants were assumed to have a male beneficiary; for deferred participants, the benefit commencement date was assumed to be the date the participant reaches age 65.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

Changes in Assumptions and Methods

There are no changes in assumptions and methods since the year-end 2016 disclosure report.

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Appendix B - Summary of principal pension plan provisions

Plan Provisions – Upper Peninsula Power Company Retirement Plan

Upper Peninsula Power Company Retirement Plan is closed to new entrants, effective as follows:

- Administrative employees effective January 1, 2008
- Non-Administrative employees effective April 19, 2009

Retirement Program for Administrative Employees

Employees included

Except for anyone who is subject to a collective bargaining agreement, an employee became a participant on January 1 or July 1 coincident with or next following the date of completion of one year of eligibility service subject to the provisions concerning closure of the plan to new entrants.

Definitions

Service considered

Year of "Eligibility Service" is the twelve month period commencing on the date of hire or rehire, or any plan year in which the employee completes 1,000 or more hours of service.

"Service credit," to determine eligibility for and the amount of benefits, is determined under the ERISA elapsed-time rules. Service credit will be earned while the employee is receiving benefits from the long-term disability plan sponsored by the company. No additional benefit service will accrue after December 31, 2012.

Compensation considered

Total compensation prior to severance from service excluding nonqualified deferred compensation payments, and extraordinary payments. Annual compensation is limited to $200,000, adjusted in accordance with Internal Revenue Code. Final average pay is the higher of the average of (a) the highest five complete calendar years of pay within the last 10 calendar years preceding severance from service, or (b) total pay for 60 months preceding severance from service. Pay after December 31, 2017 will not be considered in the calculation of final average pay.

Eligibility for Benefits

Benefit eligibility

5 years of service (3 years for employees who terminate employment on or after January 1, 2008).

Benefits Payable

Plan Benefit

(a) Benefit payable to a plan participant with 3 years of vesting service.

(b) Total Service Percent is a total of:

9% per year for the first 10 years of service;

plus 12% per year for years 11 through 20;

plus 15% per year for years 21 and thereafter.

For employees hired after December 31, 2000, the service percentages are 9%, 11% and 13%, respectively.

(c) Pension Income (lump-sum form) is equal to Total Service Percent times Final Average Pay.

(d) Minimum benefit is the lump-sum value of the benefit earned through December 31, 2000 under the plan provisions in effect at December 31, 2000.

There will be no additional service or pay increases applied to the plan benefit after December 31, 2012 and December 31, 2017, respectively. Effective January 1, 2018 the frozen accrued benefit will be increased each year until benefit commencement with annual interest credits based on the greater of (a) first segment rate defined under the Pension Protection Act for use in determining minimum lump-sum distributions under IRC 417(e), and (b) the plan's minimum interest crediting rate of 3.05%.

Pension transition

For employees employed on January 1, 2001:

(a) Calculated by taking combination of participant's age and service on January 1, 2001.

(b) Total age plus service is multiplied by 1.35% to arrive at Transition Percent (limited to 115%).

This percent is held constant until retirement or participant leaves the company and will be multiplied by Final Average Pay to determine the Pension Transition amount (payable as a lump sum). The minimum amount is $50,000 for employees who were at least age 58 and had five years of service at December 31, 2000.

Pension supplement

To be eligible for the Pension Supplement, participant must be

(a) employed on January 1, 2001;

(b) retire after January 1, 2001;

(c) be at least 55 years of age, and

(d) have 5 years of service with the company.

The Pension Supplement is payable as a fixed $800 monthly payment from retirement until age 65, or as a lump sum based on age at retirement and current interest rates.

For employees hired after January 1, 2001, eligibility for the supplement requires the participant to be age 55 with 10 years of service. The Pension Supplement amount is earned at a rate of $40 per year of service (earned prior to January 1, 2013).

Surviving spouse's benefit

(a) If the death of a vested participant occurs, the spouse will receive either a single-sum payment or a survivor annuity benefit. If the participant had designated a non-spouse beneficiary and the surviving spouse had consented, the beneficiary will receive a single-sum payment.

(b) If a participant who was receiving a monthly pension dies, the surviving spouse will receive payment in accordance with the joint and survivor option elected or the remainder of the Pension Equity Account Balance, if any.

Other Plan Provisions

Forms of payment	Preretirement death benefits are payable only as described above. Monthly pension benefits are paid as described above as a life annuity, if the participant has no spouse as of the date payments begin, or if the participant so elects. Otherwise, benefits are paid in the form of a 50% joint and survivor annuity option or, if the participant elects and the spouse consents, another actuarially equivalent optional form offered by the plan. Optional forms and actuarial equivalence are as follows:
Normal form of payment	Married participants receive a fully subsidized 50% joint & survivor annuity. The normal form of payment for unmarried participants is a single life annuity.

Optional forms of payment and conversion factors

Form of Payment	Conversion Factor
Lump Sum	Accrued PEP Balance at time of termination or retirement.
Annuity	PEP balance is converted to an annuity using the Applicable Mortality Table and Applicable Interest Rate.
Life Annuity	Calculated using annuity conversion factor with no further adjustment.
50% Joint and Survivor Annuity	Calculated using annuity conversion factor with no further adjustment unless spouse is more than 5 years younger than participant, in which case additional reductions apply.
75% Joint and Survivor Annuity	Calculated as 96% of life annuity benefit unless spouse is more than 5 years younger than participant, in which case additional reductions apply.

	100% Joint and Survivor Annuity	Calculated as 93% of life annuity benefit unless spouse is more than 5 years younger than participant, in which case additional reductions apply.
	Unreduced lifetime benefit	Participants whose spouse is greater than 5 years younger can elect to receive the equivalent of the life annuity benefit during their lifetime, with their spouse receiving an actuarially equivalent 50% survivor benefit, calculated using 6% interest and the 1971 Group Annuity Mortality Table.

Additionally, participants who are administrative employees who have joined the plan through a merged prior plan may be entitled to actuarially equivalent benefits in the following forms: single life annuity, 5, 10, or 15-year certain annuity, 25% joint and survivor annuity with or without popup, 50% joint and survivor annuity with or without popup, 66 2/3% joint and survivor annuity with or without popup, 100% joint and survivor annuity with or without popup.

Pension Increases	None
Plan participants' contributions	None
Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are not assumed for determining the AFTAP.
Benefits not valued	All benefits described in the Plan Provisions were valued as described. Willis Towers Watson in not aware of any significant benefits to be valued that were not.

Future Plan Changes

No future plan changes were recognized in determining minimum and maximum contributions.

Changes in Benefits Valued Since Prior Year

There have been no changes in benefit valued since the prior year.

Retirement Program for Non-Administrative Employees

Employees Included	An employee represented by Local Union No. 510 of the IBEW became a participant upon completion of one year of service credit subject to the provisions concerning closure of the plan to new entrants.

Definitions

Service considered	A year of service is granted for each July 1st through June 30th in which 1,000 hours are worked. In any computation period in which a participant begins, resumes, or terminates employment, 1/12th of a year of credit is given for each complete month worked.
Compensation considered	Fixed Monthly Earnings on July 1 of each year.

Eligibility for Benefits

Normal retirement benefit	On or after attainment of age 65 or, for an individual who became a participating employee after age 60, on the 4th anniversary of his date of participation.
Early retirement benefit	Available upon reaching age 55 with 10 years of service (prior to 1/1/1993: age 45 and 10 years of service).
Deferred vested benefit	In the event of termination of employment prior to age 55 and after 10 or more years of service credit. Certain participants are granted a grandfather eligibility of age 45 and 10 years of service.
Surviving spouse benefit	In the event of death of an active participant occurring after attainment 5 years of service credit. In the event of a death of a participant who was receiving a pension under the foregoing paragraphs. In the event of death of a deferred vested participant who has not commenced the benefit and who has been married for one year as of the date of death dies prior to pension commencement date.

Benefits Payable	
Normal retirement benefit	The sum of (1) 2% of Monthly Earnings as of 7/1/1980 times years of service prior to 7/1/1980 plus (2) 2% of July 1 fixed Monthly Earnings for each year after 7/1/1980 and prior to 7/1/1999 plus (3) 2.25% of July 1 fixed Monthly Earnings for each year beginning 7/1/1999.
Early retirement benefit	Monthly pension commencing as of the date designated by the participant or as of the participant's severance from service date, as the case may be, is determined in the same manner as a normal retirement benefit under the Normal Retirement Benefit paragraph above, reduced by 3% per year. Unreduced benefit becomes available upon reaching Rule of 85 for participants as of May 1, 1991.
Deferred vested benefit	Monthly pension payable as of the later of age 55 or the date designated by the employee, but not later than age 65, is determined in the same manner as an early retirement benefit under the Early Retirement Benefit paragraph
Surviving spouse benefit	The spouse to whom the participant was married to as of the date of his death will receive 50% of the pension determined under the following stipulations. This benefit will be reduced if the spouse is younger than the participant. If the death occurs after early retirement age, the base benefit is determined under the above Normal Retirement Benefit provisions, as if his date of death was his normal retirement date, based on his service credit and average monthly compensation as of his death. Payable at the later of the date of death or the date the participant would have reached age 55. If the death occurs prior early retirement age, but after 5 years of service credit and before 10 years of service credit, the base benefit is determined based upon the foregoing paragraph of Normal Retirement Benefit payable at the date the deceased member would have turned age 65. If the death occurs prior early retirement age, but after 10 years of service credit, the base benefit is determined as the total accrued monthly benefit, without reduction for early commencement. The benefit is payable on the first day of the month following the date of death. If the death of a participant who was receiving a pension under the foregoing paragraphs, the base benefit is determined as the pension the participant was receiving immediately prior to his death. If the death of a vested participant occurs prior to his pension commencement date, the base benefit is determined under the foregoing Early Retirement Benefit paragraph based on his service credit. Payable at the date of the participant's death.

Other Plan Provisions

Lump sum payments

Small lump sums will be paid if the value of benefit is $1,000 or less ($5,000 prior to March 28, 2005). Lump sums are determined based on interest rates prescribed by the Secretary of the Treasury pursuant to Section 417(e)(3) of the Code.

Normal form of payment

Married participants receive a fully subsidized 50% joint & survivor annuity. The normal form of payment for unmarried participants is a single life annuity.

Optional forms of payment and conversion factors

Plan participants from the prior Upper Peninsula Power Company Plan are also eligible for the following forms of payment using the option factors shown:

Joint and Survivor Pension
Option Factors

Age of Participant at Retirement	Option			
	100%	75%	66-2/3%	50%
45-49	.93	.95	.95	.96
50-54	.91	.93	.94	.95
55-59	.89	.92	.92	.94
60-64	.86	.89	.90	.92
65 and above	.83	.87	.88	.91

Additional age adjustments apply for participants whose spouse has an age difference of greater than three years, subject to maximum adjustments as outlined in the plan document.

Additionally, Non-Administrative employees who are participants and joined the plan through a merged prior plan may be entitled to actuarially equivalent benefits in the following forms: single life annuity, 5, 10, or 15-year certain annuity, joint and survivor annuity with or without popup.

Pension Increases

None

Plan participants' contributions

None

Maximum on benefits and pay	All benefits and pay for any calendar year may not exceed the maximum limitations for that year as defined in the Internal Revenue Code. The plan provides for increasing the dollar limits automatically as such changes become effective. Increases in the dollar limits are not assumed for determining the AFTAP.
Benefits not valued	All benefits described in the Plan Provisions were valued as described. Willis Towers Watson in not aware of any significant benefits to be valued that were not.

Future Plan Changes

No future plan changes were recognized in determining minimum and maximum contributions.

Changes in Benefits Valued Since Prior Year

There have been no changes in benefit valued since the prior year.

Line	UPPCO Information Technology (IT) CAPEX			
	IT Projects > $100K for 2018-2019			
			2018	**2019**
1		Blanket/Routine/Other Work (<$100K)	#REF!	#REF!
2	4000.01	Additional PC, Laptops, Printers, Network Hardware and Infrastructure	100,000	100,000
3	4000.01	Communications upgrade to Fiber for DAMs /Substations	50,000	100,000
4	4000.01	Cyme gateway project - interface with GIS and modeling for Maps (ESRI DB)	152,000	-
5	4000.01	GPS Mapping Sytems	-	100,000
6	4000.01	Move GIS from Secure24 to UPPCO	-	220,000
7	4000.01	OMS Ticket System GPS for Metering Trucks	-	300,000
8	4000.01	PowerPlan	1,950,000	-
9	4000.01	Radio Upgrade from Analog to Digital Radios	190,000	-
10	4000.01.01	Solution Manager - for SAP	176,000	-
11	4000.01.01	Toughbook replacement	300,000	-
12		**Total Substation Capital**	**#REF!**	**#REF!**

UPPCO Capital Expenditures (CAPEX) Summary by Business Line

	A	B	C	D	E	F	G	H	I	J
Line			**2016**	**2017**	**2018**	**2019**	**2 YR AVG.**	**2 YR VARIANCE**	**3 YR AVG.**	**3 YR VARIANCE**
1	Distribution									
2	03	Facility	-	-	9,364	-	4,682	-100.0%	3,121	-100.0%
3	04	Improve Reliability / Load Growth	2,662,275	4,742,822	4,990,000	4,725,000	4,866,411	-2.9%	4,131,699	14.4%
4	05	New Equipment / Equipment Upgrade	2,343,812	1,916,359	1,270,000	1,625,000	1,593,179	2.0%	1,843,390	-11.8%
5	06	New Customer / Service	1,205,647	905,206	1,650,000	1,570,000	1,277,603	22.9%	1,253,618	25.2%
6	07	Contractual / Regulatory / Statutory	149,250	258,357	100,000	110,000	179,179	-38.6%	169,202	-35.0%
7	**Distribution Total**		**6,360,984**	**7,822,745**	**8,019,364**	**8,030,000**	**7,921,054**	**1.4%**	**7,401,031**	**8.5%**
8	Substation									
9	05	New Equipment / Equipment Upgrade	1,297,730	779,594	635,000	755,000	707,297	6.7%	904,108	-16.5%
10	08	Special Projects	2,460,501	1,605,734	520,000	1,575,578	1,062,867	48.2%	1,528,745	3.1%
11	**Substation Total**		**3,758,231**	**2,385,328**	**1,155,000**	**2,330,578**	**1,770,164**	**31.7%**	**2,432,853**	**-4.2%**
12	Generation									
13	03	Facility	110,185	16,241	-	-	8,121	-100.0%	42,142	-100.0%
14	04	Improve Reliability / Load Growth	-	5,613	18,448	80,000	12,030	565.0%	8,020	897.5%
15	05	New Equipment / Equipment Upgrade	59,024	412,425	1,310,000	150,000	861,213	-82.6%	593,816	-74.7%
16	07	Contractual / Regulatory / Statutory	228,290	(65,423)	280,000	1,080,000	107,288	906.6%	147,622	631.6%
17	08	Special Projects	57,882	191,630	-	-	95,815	-100.0%	83,171	-100.0%
18	**Generation Total**		**455,381**	**560,486**	**1,608,448**	**1,310,000**	**1,084,467**	**20.8%**	**874,772**	**49.8%**
19	Corporate									
20	01	IT	34,649	190,976	3,131,000	983,000	1,660,988	-40.8%	1,118,875	-12.1%
21	02	Fleet	1,423,681	1,278,198	1,352,950	1,420,598	1,315,574	8.0%	1,351,610	5.1%
22	03	Facility	677,761	608,662	2,300,000	1,208,000	1,454,331	-16.9%	1,195,474	1.0%
23	08	Special Projects	19,235,503	6,396,633	9,202,218	6,933,469	7,799,425	-11.1%	11,611,451	-40.3%
24	**Corporate Total**		**21,371,595**	**8,474,468**	**15,986,168**	**10,545,067**	**12,230,318**	**-13.8%**	**15,277,410**	**-31.0%**
25	**TOTAL 5-YEAR CAPEX PLAN**		**31,946,191**	**19,243,027**	**26,768,980**	**22,215,645**	**23,006,004**	**-3.4%**	**25,986,066**	**-14.5%**
26										
27	**TOTAL CAPEX PLAN (Excluding Special Projects)**		**12,710,687**	**12,846,394**	**17,566,762**	**15,282,176**	**15,206,578**	**0.5%**	**14,374,615**	**6.3%**

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Facility CAPEX
Facility Projects > $100K for 2018-2019

Case No.: U-20276
Exhibit No.: A-28 (KEM-2)
Schedule:

Witness: Keith E. Moyle

UPPCO Facility CAPEX

Line	Facility Projects > $100K for 2018-2019			
			2018	**2019**
1	4000	Blanket/Routine/Other Work (< $100K)	-	-
2	4000.03	General Facility Improvements	400,000	408,000
3	4000.03	Headquarters-Expansion and Renovation		500,000
4	4000	Ishpeming South Building-Expansion and Renovation	1,200,000	
5	4000.03	Ishpeming North Building-HVAC Replacement and Renovation	700,000	
6	4000.03	Munising Service Center-Sale & Relocation (Building Purchase & Remodel)		300,000
7		**Total Facility Capital**	**2,300,000**	**1,208,000**

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Substation CAPEX
Substation Projects > $100K for 2018-2019

Case No.: U-20276
Exhibit No.: A-29 (KEM-3)
Schedule:
Page: 1 of 1
Witness: Keith E. Moyle

UPPCO Substation CAPEX

Line	Substation Projects > $100K for 2018-2019			
			2018	**2019**
1	2000	Blanket/Routine/Other Work (< $100K)	310,000	330,000
2	2000.05.02	Henry Street RTU Upgrade	-	125,000
3	2000.05.02	L'Anse RTU Upgrade	-	125,000
4	2000.05.05	Munising Bkr 635 (2.4KV) replacement - RMAG	125,000	-
5	2000.05.09	Lincoln Ave. RTU Upgrade (4 Feeders, 2 Banks)	200,000	-
6	2000.08.04	Barnum Substation Add Two Circuits	50,000	250,000
7	2000.05.10	Upgrade Perch Lake grounding		100,000
8	2000.05.06	Upgrade Munising Substation Feeder Reclosers		150,000
9	2000.08.04	Winona Substation Inductor	50,000	100,000
10	2000.05.06	Upgrade M-38 Substation recloser and RTU upgrade		150,000
11	2000.08.04	Forsyth Substation 2-12KV Feeder Addition (Including New Transformer)	50,000	815,578
12	2000.08.04	Shingleton Add RTU (Similar to Seney and Bayview)	-	125,000
13	2000.08.04	Upgrade Hoist GSU Transformer	195,000	30,000
14	2000.08.04	Upgrade Mather A Transformer	175,000	30,000
15		**Total Substation Capital**	**1,155,000**	**2,330,578**

UPPCO Generation CAPEX

Line	Generation Projects > $100K for 2018-2019			
			2018	**2019**
1	3000	Blanket/Routine/Other Work (<$100K)	181,948	230,000
2	3000.05.05	Hoist - Automation & Protection Upgrade	1,138,000	-
3	3000.07.02	Prickett - Slope Stabilization	110,000	800,000
4	3000.07.02	Victoria- Penstock Culvert Drain System	48,000	250,000
5	3000.07.02	Victoria - Slope Stabilization	130,500	30,000
6		**Total Generation Capital**	**1,608,448**	**1,310,000**

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Distribution Reliability CAPEX
Distribution Projects > $50K for 2018-2019

Case No.: U-20276
Exhibit No.: A-31 (KEM-5)
Schedule:

Witness: Keith E. Moyle

UPPCO Distribution Reliability CAPEX

Distribution Projects > $50K for 2018-2019

Line	Improve Reliaiblity | Load Growth		2018	2019	2020
1	1000.04.02	Blanket/Routine/Other Work (< $50K)	1,360,000	1,475,000	1,275,000
2	1000.04.02	MUN 617 Summer Homes Rd URD Part 1	95,000		
3	1000.04.02	MSV 989 Rebuild	150,000		
4	1000.04.02	KIS 1275 Old Sawyer School Move to Sawyer Residential	115,000		
5	1000.04.02	KIS 1275 Feed Sporley Lk Area from KI Sawyer Residential	405,000		
6	1000.04.02	BRM 1231 Aspen Dr/Lilac St URD Replacement	120,000		
7	1000.04.02	BNM 139 34.5KV System Through Negaunee UG	230,000		
8	1000.04.02	SNY 631 ATC Underbuild 2Phase to 3Phase Section	120,000		
9	1000.04.02	PLK 401 Grant Lake UG to OH	175,000		
10	1000.04.02	BAY 515 Lake Bluff UG replacement	150,000		
11	1000.04.02	DTA 589 9th Lane Copper replacement	120,000		
12	1000.04.02	KWN 927 Eagle River-Eagle Harbor Tie	180,000		
13	1000.04.02	KWN 927/929 Automation	100,000		
14	1000.04.02	HEN 1017 Chassell-Painesdale Tie East Half OH	215,000		
15	1000.04.02	HEN 1017 Chassell-Painesdale Tie West Half URD	450,000		
16	1000.04.02	WNA 907 Cottage Lane URD replacement-Twin Lakes	100,000		
17	1000.04.02	ATL 891 Larson Road URD replacement	275,000		
18	1000.04.02	LIN 3063 Bates Amasa Part 3	200,000		
19	1000.04.02	OSC 703 Tecumseh Rd Relocate	150,000		
20	1000.04.02	WNA 907 Emily Lake URD Replacement	150,000		
21	1000.04.02	ATL 891 Red Brick Road URD replacement	130,000		
22	1000.04.02	GWN 657 Feed Sporley Lk Area from KI Sawyer Residential Part 2		175,000	
23	1000.04.02	DLT 989 Delta L.5 (Log Jam Rd) Lane Copper Replacement		300,000	
24	1000.04.02	PLK 401 M95 single phase URD (Witch Lake area)		175,000	
25	1000.04.02	GWN 657 Engman Lake URD Replacement		450,000	
26	1000.04.02	FRY/GWN Forsyth Sub FDR to Gwinn Sub URD		400,000	
27	1000.04.02	MUN 617 Summer Homes Rd Part 2 Lake Crossing		175,000	
28	1000.04.02	KWN 927 Popeye Rock OH to UG Conversion Part 1		500,000	
29	1000.04.02	OSC 719 Bootjack to Jacobsville URD Tie		300,000	
30	1000.04.02	ATL 891 Freda URD Replacement		300,000	
31	1000.04.02	ATL 895 Relocate South Range Line to Highway		200,000	
32	1000.04.02	OSC 717 5-Mile Point URD Tie		150,000	
33	1000.04.02	ELE 1121 Point Mills OH to URD conversion		125,000	
34	1000.04.02	BNM 139 35kv TV6 to McClure Rebuild Line			200,000
35	1000.04.02	PLK 401 Fence River Road URD (west end of road)			200,000
36	1000.04.02	PLK 401/403 Perch Lake Tie to Underground			450,000
37	1000.04.02	DTA Sub Ties 589/585 & 583/587			250,000
38	1000.04.02	MUN 617 Reindeer Run URD			200,000
39	1000.04.02	FRE 203 35KV Rebuild Lindberg Tap (metal structures/URD)			200,000
40	1000.04.02	BNM Sub Cooper Lake New Feeder			50,000
41	1000.04.02	BNM Sub National Mine New Feeder			50,000
42	1000.04.02	PLK 401 Squaw Lake URD			200,000
43	1000.04.02	KWN 927 Popeye Rock OH to URD Conversion Part 2			500,000
44	1000.04.02	ATL 895 Relocate Circuit from South Range to Painesdale			400,000
45	1000.04.02	OSC 719 Rabbit Bay OH to URD Conversion			350,000
46	1000.04.02	KWN 927-Eagle Harbor OH to URD conversion			150,000
47	1000.04.02	LIN 3063 Lake Emily Iron River OH to URD Conversion			100,000
48	**Total Improve Reliability | Load Growth Distribution Capital**		**4,990,000**	**4,725,000**	**4,575,000**

Michigan Public Service Commission
Upper Peninsula Power Company
Reliability Indices as filed
2013 - 2017

Case No.: U-20276
Exhibit No. A-32 (KEM-6)
Schedule:
Page: 1 of 1
Witness: Keith E. Moyle

Upper Peninsula Power Company (UPPCO)
Reliability Indices as filed

Line	Year	All Weather						Excluding MEDs per IEEE 1366-2003*					
		SAIDI		SAIFI		CAIDI		SAIDI		SAIFI		CAIDI	
		Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.
1	2013	297		1.89		157		249		1.79		139	
2	2014	281		1.85		152		248		1.78		140	
3	2015	161		1.30		124		122		1.10		111	
4	2016	457		2.07		221		165		1.32		125	
5	2017[2]	573	354	2.08	1.84	276	186	176	192	1.23	1.44	143	132

1) UPPCo did not adopt the IEEE 1366-2003 for MED tracking until 2012.
"**Major Storm**" Definition:
Weather conditions that exceed system design limits and which satisfy all of the following:
a. Extensive mechanical damage to the electric system.
b. Outages involving more than 10% of customers served by district.
c. More than1% of the customers service have not been restored within 24 hrs.

2) Beginning in 2017, UPPCO excludes transmission-caused outages from "All Weather" and "Excluding MEDs" data

Upper Peninsula Power Company (UPPCO)
Reliability Indices as revised

Line	Year	All Weather						Excluding MEDs per IEEE 1366-2003*					
		SAIDI		SAIFI		CAIDI		SAIDI		SAIFI		CAIDI	
		Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.	Annual	5 yr Avg.
1	2013	273		1.75		156		245		1.68		146	
2	2014	264		1.68		157		231		1.60		144	
3	2015	151		1.23		123		113		1.04		109	
4	2016	265		1.55		170		157		1.23		128	
5	2017[2]	573	305	2.08	1.66	276	177	176	184	1.23	1.36	143	134

1) UPPCo did not adopt the IEEE 1366-2003 for MED tracking until 2012.

"**Major Storm**" Definition:

Weather conditions that exceed system design limits and which satisfy all of the following:

a. Extensive mechanical damage to the electric system.
b. Outages involving more than 10% of customers served by district.
c. More than1% of the customers service have not been restored within 24 hrs.

2) Beginning in 2017, UPPCO excludes transmission-caused outages from "All Weather" and "Excluding MEDs" data

Michigan Public Service Commission
Upper Peninsula Power Company
Major Event Days ("MEDs")
2013 - 2017

Case No.: U-20276
Exhibit No.: A-34 (KEM-8)
Schedule:
Page: 1 of 1
Witness: Keith E. Moyle

Line	Year	TMED	#MEDs	Ave # UPPCO Cust
1	2013	22.0	1	60,202
2	2014	26.7	1	59,537
3	2015	27.8	1	59,512
4	2016	23.4	3	59,444
5	2017	20.2	5	59,298

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO 2013-2017 All Weather Outages By Cause
5 year average

Case No.:	U-20276
Exhibit No.:	A-35 (KEM-9)
Schedule:	
Page:	1 of 1
Witness:	Keith E. Moyle

UPPCO 2013-2017 All Weather Outages By Cause

Line	Cause Description	Events	%	SAIDI	%	SAIFI	%
1	Tree	2,714	31%	629	35%	3.37	36%
2	Weather	956	11%	406	23%	1.12	12%
3	Transmission	98	1%	268	15%	0.96	10%
4	Dist Equip Fail	1,782	20%	161	9%	1.09	12%
5	Unknown/Other	1,193	13%	128	7%	1.04	11%
6	Vehicle Accident	198	2%	100	6%	0.61	7%
7	Planned Outage	592	7%	47	3%	0.50	5%
8	Animals	1,174	13%	41	2%	0.39	4%
9	Human Error	96	1%	9	1%	0.14	1%
10	Underground Dig In	58	1%	5	0%	0.04	0%
11	5-Year Total	8,861	100%	1,794	100%	9.25	100%

UPPCO Pole Inspection History

Line			HOU	IR	ONT	ISH	MUN	DEL	UPPCO
1	2015	# Poles	2260	516	433	1339	644	1116	6308
2		#Dang/Reject	121	16	44	72	12	69	334
3		%	5.4%	3.1%	10.2%	5.4%	1.9%	6.2%	5.3%
4		Cost	$57,715	$12,975	$10,817	$30,123	$11,416	$27,914	$150,961
5									
6	2016	# Poles	1872	391	332	1507	619	1155	5876
7		#Dang/Reject	89	4	17	44	19	8	181
8		%	4.8%	1.0%	5.1%	2.9%	3.1%	0.7%	3.1%
9		Cost	$51,571	$8,615	$9,131	$34,048	$14,730	$22,570	$140,666
10									
11	2017	# Poles	2393	396	258	2891	779	1154	7871
12		#Dang/Reject	75	3	4	162	20	68	332
13		%	3.1%	0.8%	1.6%	5.6%	2.6%	5.9%	4.2%
14		Cost	$63,887	$8,570	$5,889	$71,856	$13,499	$15,537	$179,239
15									
16	3-year Ave	# Poles	2175	434	341	1912	681	1142	6685
17		#Dang/Reject	95	8	22	93	17	48	282
18		%	4.4%	1.8%	6.4%	4.8%	2.5%	4.2%	4.2%
19		Cost	$57,724	$10,054	$8,613	$45,342	$13,215	$22,007	$156,955

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Underground Inspection History
2015 - 2017

Case No.: U-20276
Exhibit No.: A-37 (KEM-11)
Schedule:
Page: 1 of 1
Witness: Keith E. Moyle

UPPCO Underground Inspection History

Line			HOU	IR	ONT	ISH	MUN	DEL	UPPCO
1	2015	# Cabinets	809	34	122	61	54	47	1127
2		#Rec Refinish*	0	0	0	0	0	0	0
3		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4		Cost	$37,985	$2,556	$4,519	$2,420	$2,035	$1,659	$51,173
5									
6	2016	# Cabinets	225	36	112	403	47	357	1180
7		#Rec Refinish	23	3	2	20	2	36	86
8		%	10.2%	8.3%	1.8%	5.0%	4.3%	10.1%	7.3%
9		Cost	$10,624	$1,815	$3,962	$14,691	$1,870	$10,036	$42,999
10									
11	2017	# Cabinets	320	48	42	357	82	130	979
12		#Rec Refinish	38	5	3	27	7	14	94
13		%	11.9%	10.4%	7.1%	7.6%	8.5%	10.8%	9.6%
14		Cost	$33,454	$4,646	$1,760	$25,985	$3,178	$15,221	$84,244
15									
16	3-year Ave	# Cabinets	451	39	92	274	61	178	1095
17		#Rec Refinish	20	3	2	16	3	17	60
18		%	4.5%	6.8%	1.8%	5.7%	4.9%	9.4%	5.5%
19		Cost	$27,355	$3,006	$3,414	$14,365	$2,361	$8,972	$59,472

20 * "Recommended Refinish" was added in 2016; therefore, this inspection point was NULL in 2015

Michigan Public Service Commission
Upper Peninsula Power Company
System Hardening and Reliability Projects
2019 - 2020

Case No.:	U-20276
Exhibit No.:	A-38 (KEM-12)
Schedule:	
Page:	1 of 1
Witness:	Keith E. Moyle

System Hardening and Reliability Projects
2019 - 2020

Line	**2019 Distribution SHARP CapEx Projects**				**RASCL**	**Estimated Cost**
1	1	East	1000.04.02	GWN 657 Feed Sporley Lk Area from KI Sawyer Residential Part 2	RA	$175,000
2	2	East	1000.04.02	DLT 989 Delta L.5 (Log Jam Rd) Lane Copper Replacement	RA	$300,000
3	3	East	1000.04.02	PLK 401 M95 single phase URD (Witch Lake area)	RA	$175,000
4	4	East	1000.04.02	GWN 657 Engman Lake URD Replacement	RA	$450,000
5	5	East	1000.04.02	FRY/GWN Forsyth Sub FDR to Gwinn Sub URD	R	$400,000
6	6	East	1000.04.02	MUN 617 Summer Homes Rd Part 2 Lake Crossing	RA	$175,000
7	7	West	1000.04.02	KWN 927 Popeye Rock OH to UG Conversion Part 1	RA	$500,000
8	8	West	1000.04.02	OSC 719 Bootjack to Jacobsville URD Tie	R	$300,000
9	9	West	1000.04.02	ATL 891 Freda URD Replacement	RA	$300,000
10	10	West	1000.04.02	ATL 895 Relocate South Range Line to Highway	RA	$200,000
11	11	West	1000.04.02	OSC 717 5-Mile Point URD Tie	R	$150,000
12	12	West	1000.04.02	ELE 1121 Point Mills OH to URD conversion	RA	$125,000
13				**Total**		**$3,250,000**
14						
15	**2020 Distribution SHARP CapEx Projects**				**RASCL**	**Estimated Cost**
16	1	East	1000.04.02	BNM 139 35kv TV6 to McClure Rebuild Line	RA	$200,000
17	2	East	1000.04.02	PLK 401 Fence River Road URD (west end of road)	RA	$200,000
18	3	East	1000.04.02	PLK 401/403 Perch Lake Tie to Underground	RA	$450,000
19	4	East	1000.04.02	DTA Sub Ties 589/585 & 583/587	R	$250,000
20	5	East	1000.04.02	MUN 617 Reindeer Run URD	RA	$200,000
21	6	East	1000.04.02	FRE 203 35KV Rebuild Lindberg Tap (metal structures/URD)	RA	$200,000
22	7	East	1000.04.02	BNM Sub Cooper Lake New Feeder	R	$50,000
23	8	East	1000.04.02	BNM Sub National Mine New Feeder	R	$50,000
24	9	East	1000.04.02	PLK 401 Squaw Lake URD	RA	$200,000
25	10	West	1000.04.02	KWN 927 Popeye Rock OH to URD Conversion Part 2	RA	$500,000
26	11	West	1000.04.02	ATL 895 Relocate Circuit from South Range to Painesdale	RA	$400,000
27	12	West	1000.04.02	OSC 719 Rabbit Bay OH to URD Conversion	RA	$350,000
28	13	West	1000.04.02	KWN 927-Eagle Harbor OH to URD conversion	RA	$150,000
29	14	West	1000.04.02	LIN 3063 Lake Emily Iron River OH to URD Conversion	RA	$100,000
30				**Total**		**$3,300,000**
31	*RASCL: R – Reliability/Storm Hardening A – Age & Condition S – Safety C – Compliance/Voltage L – Load/Capacity*					

Michigan Public Service Commission
Upper Peninsula Power Company
6-Year Cycle Distribution Line Clearance Program
2019 - 2024

Case No.: U-20276
Exhibit No.: A-39 (KEM-13)
Schedule:

Witness: Keith E. Moyle

Line								
	Upper Peninsula Power Company (UPPCO)							
	6-Year Cycle Distribution Line Clearance Program							
		Historical	**Projected**					
1		**2017**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	**MPSC Case No.**	U-17274						
3	**Cost**	$ 3,257,207	$ 2,330,500	$ 2,330,500	$ 2,330,500	$ 2,330,500	$ 2,330,500	$ 2,330,500
4	**Line Miles**	475	401	401	401	401	401	401
5	**Cost Variance From 2017**		$ (926,707)					

Revenue Offset (Credit) Update

Line No.	Description	Notes	Formula	(a) TOTAL	(b) actual 2016	(c) actual 2017	(d) 2018	(e) 2019	(f) 2020	(g) 2021
					Calendar Year					
1	Net Income Available for Common (actual)	*1*	*input*		7,511,875	7,456,798				
2	Average Common Equity	*2*	*input*		121,117,557	124,254,333				
3	Earned Rate of Return on Common Equity	*3*	*Line 1 / Line 2*		6.20%	6.00%				
4	Authorized Return on Equity	*4*	*input*		10.00%	10.00%				
5	Planned Revenue Offset (U-17564)	*5*	*$26M / 6 years*	(26,000,000)	(4,333,333)	(4,333,333)	(4,333,333)	(4,333,333)	(4,333,333)	(4,333,333)
6	Planned Cumulative Revenue Offset (U-17564)		*calc.*		(4,333,333)	(8,666,667)	(13,000,000)	(17,333,333)	(21,666,667)	(26,000,000)
7	Planned Net Income Impact of Revenue Offset (Pre-TCJA)	*6*	*Revenue Offset / 1.6367*	(18,167,132)	(2,647,604)	(2,647,604)				
8	Planned Net Income Impact of Revenue Offset (Post-TCJA)		*Revenue Offset / 1.3466*				(3,217,981)	(3,217,981)	(3,217,981)	(3,217,981)
9	Adjusted Net Income Available for Common	*7*	*Line 1 - sum (Line 7 + Line 8)*		10,159,479	10,104,402				
10	Authorized Net Income Available for Common	*8*	*Line 2 * Line 4*		12,111,756	12,425,433				
11	Additional Net Income Deficiency (U-17564)	*9*	*Line 9 - Line 10*		(1,952,277)	(2,321,031)	-	-	-	-
12	Additional Revenue Offset Deficiency (U-17564) Pre-TCJA	*10*	*Line 11 * 1.6367*		(3,195,291)	(3,798,832)				
13	Additional Revenue Offset Deficiency (U-17564) Post-TCJA		*Line 11 * 1.3466*				-	-	-	-
14	Actual Total Revenue Offset Update	*11*	*Line 14 + Line 6*		(7,528,625)	(8,132,165)	(4,333,333)	(4,333,333)	(4,333,333)	(4,333,333)
15	Actual Cumulative Revenue Offset	*12*	*calc.*		(7,528,625)	(15,660,790)	(19,994,123)	(24,327,457)	(28,660,790)	(32,994,123)
16	Remaining Revenue Offset			(10,339,210)						
17										
18	Pre-TCJA Revenue Conversion Factor		*1.6367*		1.6367	1.6367				
19	Post-TCJA Revenue Converstion Factor		*1.3466*				1.3466	1.3466	1.3466	1.3466
20										
21	Proposed Updated Revenue Offset			(26,000,000)	(7,528,625)	(8,132,165)	(2,584,802)	(2,584,802)	(2,584,802)	(2,584,802)

Notes

1 *source: A-1 A2 Pg4, actual net income for rate making purposes*

2 *source: A-1 A2 Pg4*

3 *source: A-1 A2 Pg4*

4 *source: A-1 A2 Pg4*

5 *In the June 6, 2014 order in Case No. U-17564, the Commission approved a settlement agreement authorizing the sale of UPPCo by Integrys Energy Group, Inc., (Integrys) to Balfour Beatty Infrastructure Partners, L.P. (BBIP) and Upper Peninsula Power Holding Company (UPPHC). UPPCo is now a subsidiary of UPPHC. One of the terms of the settlement provides that "Following closing of the [sale], UPPCo shall provide a revenue offset of $26 million spread over six consecutive years to be applied to the distribution portion of each applicable tariff, effective with the date rates go into effect as approved in its next base rate case." June 6, 2014 order in Case No. U-17564, p. 4.*

6 *$26 million divided by revenue conversion factor, both pre-TCJA and post-TCJA to derive net income impairment*

7 *Adjusted net income from Line 1, excluding planned revenue offset from Line 7 & Line 8*

8 *Average common equity multiplied by authorized ROE from Line 4*

9 *Additional income deficiency = authorized net income less adjusted net inocme*

10 *Line 7 multiplied by pre and post-TCJA revenue conversion factors*

11 *Planned revenue offset + additional revenue offset due to income deficiency*

12 *Cumulative, year over year, impact of Note 11*

Michigan Public Service Commission
Upper Peninsula Power Company
Summary of Projected 2019 Escanaba Facility Hydro Forecast Adjustments
2019 Projected Test Year

Case No.: U-20276
Exhibit No.: A-41 (GRH-3)
Schedule:

Witness: Gradon R. Haehnel

	Summary of Projected 2019 Escanaba Facility Hydro Forecast Adjustments			
	A	B	C	D
Line	Category	Forcast Adjustment No.	Description	Value
1	**Revenue Adjustments**			
2	Escanaba Hydro - current contract revenue	1	2019 Projected Revenue - current contract	1,114,883
3	Escanaba Hydro - updated contract revenue	2	2019 Increment Revenue - updated contract	1,247,836
4	Sub-total Revenue Adjustments			2,362,719
5				
6	**Expense Adjustments**			
7	Escanaba Hydro OPEX	3	2019 Projected Expense - current contract	1,024,592
8	Escanaba Depreciation	4	Depreciation Expense	213,534
9	Escanaba Property Tax	5	Property Tax Expense	30,000
10	Sub-total Expense Adjustments			1,268,126
11				
12	**Balance Sheet Adjustments**			
13	Escanaba Hydro Plant in Service	6	Book Value	9,294,220
14	Escanaba Hydro Accum Depr Res	7	Accumulated Depreciation	(2,231,905)
15	Sub-total Balance Sheet			7,062,315

UPPER PENINSULA POWER COMPANY
DETERMINATION OF NEW PSCR BASE RATE FACTOR AND NEW PSCR LOSS FACTOR
PROJECTED TEST YEAR ENDED DECEMBER 31, 2019

PRELIMINARY 2019 PSCR Plan	
FERC Account	**Total UPPCO**
501 (Fuel Costs)	$0
547 (Fuel Costs)	$261,191
555 (Purchased Power)	$24,962,350
561, 565, 567, 575 (Transmission Costs)	$7,624,160
Total Fuel, Purchased Power & Transmission O&M	**$32,847,701**
447 (Opportunity sales)	($453)
442 (RTMP sales)	($7,887,106)
442 (RTMP Transmission)	($1,196,689)
447 (Capacity Sales)	$468
447 (Ancillary Services)	$0
Total Opportunity, RTMP, Capacity Sale & REC Revenues	**($9,083,780)**
Net PSCR Costs	**$23,763,921**
Generation plus Purchases less Opportunity Sales and RTMP Sales (Mwhs)	**565,614**
System Requirement Sales subject to PSCR Factor (Mwhs)	**532,443**
Average PSCR Cost ($/Mwh)	**$42.01**
Current PSCR Base Rate ($/Mwh)	**$58.57**
Average PSCR Cost less PSCR Base Rate	**-$16.56**
Current PSCR Loss Factor	**1.0623**
PSCR Factor with CURRENT PSCR Base Rate & Loss Factor ($/Mwh)	**-$17.59**
CURRENT PSCR Base Rate on Sales excluding losses ($/Mwh)	**$62.22**

PROPOSED NEW PSCR BASE RATE, PSCR LOSS FACTOR, AND PSCR FACTOR	
FERC Account	**Total UPPCO**
501 (Fuel Costs)	$0
547 (Fuel Costs)	$261,191
555 (Purchased Power)	$24,962,350
561, 565, 567, 575 (Transmission Costs)	$7,624,160
Total Fuel, Purchased Power & Transmission O&M	**$32,847,701**
447 (Opportunity sales)	($453)
442 (RTMP sales)	($7,887,106)
442 (RTMP Transmission)	($1,196,689)
447 (Capacity Sales)	$468
447 (REC Sales)	$0
Total Opportunity, RTMP, Capacity Sale & REC Revenues	**($9,083,780)**
Net PSCR Costs	**$23,763,921**
Generation plus Purchases less Opportunity Sales and RTMP Sales (Mwhs)	**565,614**
System Requirement Sales subject to PSCR Factor (Mwhs)	**532,443**
Average PSCR Cost ($/Mwh)	**$42.01**
PROPOSED PSCR BASE RATE ($/Mwh)	**$42.01**
Average PSCR Cost less PSCR Base Rate	**$0.00**
PROPOSED PSCR Loss Factor	**1.0623**
PSCR Factor with PROPOSED PSCR Base Rate & Loss Factor ($/Mwh)	**$0.00**
PROPOSED PSCR Base Rate on Sales excluding losses ($/Mwh)	**$44.63**

COMPARISON OF PROPOSED TO CURRENT PSCR RATES	
PROPOSED PSCR Base Rate on Sales excluding losses ($/Mwh)	**$44.63**
PSCR Factor with PROPOSED PSCR Base Rate & Loss Factor ($/Mwh)	**$0.00**
PROPOSED PSCR Base Rate on Sales plus PSCR Factor ($/Mwh)	**$44.63**
CURRENT PSCR Base Rate on Sales excluding losses ($/Mwh)	**$62.22**
PSCR Factor with CURRENT PSCR Base Rate & Loss Factor ($/Mwh)	**-$17.59**
CURRENT PSCR Base Rate on Sales plus PSCR Factor ($/Mwh)	**$44.63**
PROPOSED minus CURRENT PSCR Base Rate on Sales plus PSCR Factor ($/Mwh)	**$0.00**
System Requirement Sales subject to PSCR Factor (Mwhs)	**532,443**
Revenue Requirement Impact of PSCR Loss Factor Change	**-$8**

May not cross-check due to rounding.

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC 7~~6~~th Rev. Sheet No. D-1.00
Replaces 6~~5~~th Rev. Sheet No. D-1.00

D1. Power Supply Cost Recovery **PSCR**

A. PSCR Factors:

All rates for electric service shall include an amount up to the Power Supply Cost Recovery Factor (the PSCR Factor) for the specified billing period as set forth below.

R The PSCR Factors for a given month will consist of an increase or decrease of 0.010623~~038~~ mills per kWh for all customers in the Integrated System and in the Iron River System for each full 0.01 mill increase or decrease in the projected
R power supply costs for that month above or below a cost base of 42.01~~58.57~~ mills per kWh, rounded to the nearest one-hundredth of a mill per kWh. The projected power supply costs per kWh shall equal the total projected net power cost in that month divided by the sum of that month's projected net system kWh requirements. Net system kWh requirements shall be the sum of net kWh generation and net kWh purchased and interchanged.

An amount not exceeding the PSCR Factor for each month shall be placed into effect in the first billing cycle of that monthly billing period and shall continue in effect until the first billing cycle of a subsequent month for which a subsequent PSCR Factor becomes operative.

B. Monthly Reports:

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

C. Annual Reconciliation:

All fuel cost and purchased and net interchanged power revenues received by the Company, whether included in base rates or collected pursuant to a fuel and purchased power cost adjustment clause or a power supply cost recovery clause, shall be subject to annual reconciliation with the cost of fuel and purchased and net interchanged power. Such annual reconciliations shall be conducted in accordance with the reconciliation procedures described in Section 6j (12) to (18) of 1939 PA 3, as amended, including the provisions for refunds, additional charges, deferral and recovery, and shall include consideration by the Commission of the reasonableness and prudence of expenditures charged pursuant to any fuel and purchased power cost adjustment clause in existence during the period being reconciled.

Continued on Sheet No. D-2.00

Issued: 09~~10~~-~~25~~24-~~16~~2018
By G R Haehnel~~S C Devon~~ ____________
07~~10~~-~~1~~XX-218~~16~~
Director – Regulatory Affairs
Marquette, Michigan

Effective for Service
____________ On and After:

Issued Under Auth. of
Mich Public Serv Comm
Dated: 07~~9~~-~~23~~XX-18~~6~~
In Case No. U-20276~~17911~~

Case No. U-20276

Witness: Eric W. Stocking
Exhibit A-42
Schedule F2

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC ~~129th~~ XXth Revised Sheet No. D-2.00
(2018 Rate Case~~PSCR Plan~~, Case No. U-~~18406~~20276) Replaces ~~128th~~ XXth Revised Sheet No. D-2.00

D1. Power Supply Cost Recovery **PSCR**

Continued from Sheet No. D-1.00

Should the Company apply lesser factors than those below, or if the factors are later revised pursuant to Commission Orders or 1982 PA 304, the Company will notify the Commission and file a revision of the following list.

ALL CLASSES

Power Supply Cost Recovery Factors

	Billing Months	Authorized 2019~~8~~ Plan Year PSCR Factor $/kWh	Prior Years Over/Under Recovery Factor $/kWh	Maximum Authorized 2019~~8~~ PSCR Factor $/kWh	Actual Factor Billed $/kWh
R	January 2019~~8~~	($~~0.~~0.01665~~0~~)~~1665)~~	($0.00000)	($0.01665)	~~($0.02474)~~
R	February 201~~8~~9	($0.01665)	($0.00000)	($0.01665)	~~($0.02474)~~
R	March 2019~~8~~	($0.01665)	($0.00000)	($0.01665)	~~($0.02474)~~
R	April 2019~~8~~	($0.01665)	($0.00000)	($0.01665)	~~($0.02474)~~
R	May 2019~~8~~	($0.01665)	($0.00000)	($0.01665)	~~($0.03000)~~
R	June 2019~~8~~	($0.01665)	($0.00000)	($0.01665)	
R	July 2019~~8~~	($0.01665)	($0.00000)	($0.01665) ~~($0.01665)~~	
R	August 201~~8~~9	($0.~~01665~~00000)	($0.00000)	($0.00000)~~($0.01665)~~	
R	September 201~~8~~9	($0.00000)~~($0.01665)~~	($0.00000)	($0.00000)~~($0.01665)~~	
R	October 2019~~8~~	($0.00000)~~($0.01665)~~	($0.00000)	($0.00000)~~($0.01665)~~	
R	November 201~~8~~9	($0.00000)~~($0.01665)~~	($0.00000)	($0.00000)~~($0.01665)~~	
R	December 2019~~8~~	($0.00000)~~($0.01665)~~	($0.00000)	($0.00000)~~($0.01665)~~	

Continued on Sheet No. D-3.00

Issued: 09-24-2018
By G R Haehnel
Director – Regulatory Affairs
Marquette, Michigan

Effective for Service
On and After: 07-XX-218
Issued Under Auth. of
Mich Public Serv Comm
Dated: 07-XX-18
In Case No. U-20276

U-17000 Report to the Commission

Prepared by the Staff of the Michigan Public Service Commission

June 29, 2012

EXECUTIVE SUMMARY

The smart grid encompasses technological improvements to the electric grid designed to increase reliability, reduce outage time, accommodate the integration of distributed generation sources, and improve electric vehicle charging capacity. Advanced Metering Infrastructure (AMI) systems "combine meters with two-way communication capabilities. These systems typically are capable of recording near-real-time data on power consumption and reporting that consumption to the utility at frequencies of an hour or less".[1] AMI meters are also known as smart meters, and they represent one component of an improved or smart grid.

On January 12, 2012, the Michigan Public Service Commission (Commission) issued an order in Case No. U-17000. This order directed the utilities to provide information by March 16, 2012, regarding their plans for smart meter deployment including proposed costs and benefits, scientific information addressing the safety of smart meter deployment, assurance of customer data privacy and other information. The order also allowed for public comments in response to the utilities' filings to be submitted by April 16, 2012.

Approximately 400 residential customer comments were received. The vast majority of these comments voice concerns about the installation of smart meters. The concerns can generally be categorized into the following topics: health and safety, privacy/data security, cyber security and bill impacts.

The Staff has engaged in a thorough review of resources in response to public concerns about smart meters. The resources fall into one or more of the following categories: technical in nature, relevant to smart meter technology, research focused, science based, peer reviewed, commentary and/or opinion.

The Staff's review supports the following conclusions:

- Smart meters are quickly becoming the primary replacement meter to the existing electromechanical meters because they are more accurate, enhance outage response and offer opportunities for customer energy management. The traditional electromechanical meter is obsolete and currently not in production.
- Smart meters are an important component to the success of a much larger picture, an emerging smart grid. As the United States Department of Energy (U.S. DOE) states "[a] smart grid uses digital technology to improve the reliability, security, and efficiency of the electricity system . . . ."[2]
- After careful review of the available literature and studies, the Staff has determined that the health risk from the installation and operation of metering systems using radio transmitters is insignificant. In addition, the appropriate federal health and safety regulations provide assurance that smart meters represent a safe technology.

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[1] Massachusetts Institute of Technology, *The Future of the Electric Grid*; An Interdisciplinary MIT Study, 2011, p.133. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf
[2] U.S. Department of Energy, *2010 Smart Grid System Report*, February 2012, Message from the Assistant Secretary. http://energy.gov/sites/prod/files/2010%20Smart%20Grid%20System%20Report.pdf

- Data privacy and cyber security continue to be priorities for customers, utilities and the Commission. Data protection procedures are continually being updated at the national and state levels. Michigan utilities currently have large amounts of critical customer information that they have safeguarded for years and will continue to adequately safeguard. Several national organizations are focused on monitoring and improving cyber security efforts that will continue to guide electric service providers' efforts.

The Staff's Recommendations

Smart Meter Implementation: Smart meters are part of the larger smart grid initiative that is being pursued by investor-owned and other utilities throughout the world. The smart grid initiative has been endorsed by federal laws and the technologies have been declared to be safe by accredited national agencies and industry councils. The Staff recommends that the Commission regulated utilities in Michigan continue to assess smart grid technologies as part of their efforts to improve the reliability and efficiency of the grid. AMI investments should continue to be reviewed by the Commission in contested rate cases.

Opt-out: A minority of customers have expressed concerns about smart meters. The Staff understands that some people remain opposed to the installation of smart meters for a number of reasons and should be allowed to opt-out. The Staff believes that ratemaking for the opt-out provision should be based on cost of service principles. If AMI meters result in a reduced cost of service, this could be accounted for by either an additional charge for those customers choosing to opt-out or a discount for those customers with an AMI meter.

Revised Rules and/or Tariffs: Several comments reflect concerns about customer privacy and data security. The Staff recommends there be additional consideration to ensure consistent protection of customer privacy and data.

Smart Grid Vision: The Staff has created a comprehensive smart grid vision which provides an all-inclusive perspective of the emerging smart grid. The vision will provide a framework for future grid modernization.

Details of these recommendations are contained in the body of this report.

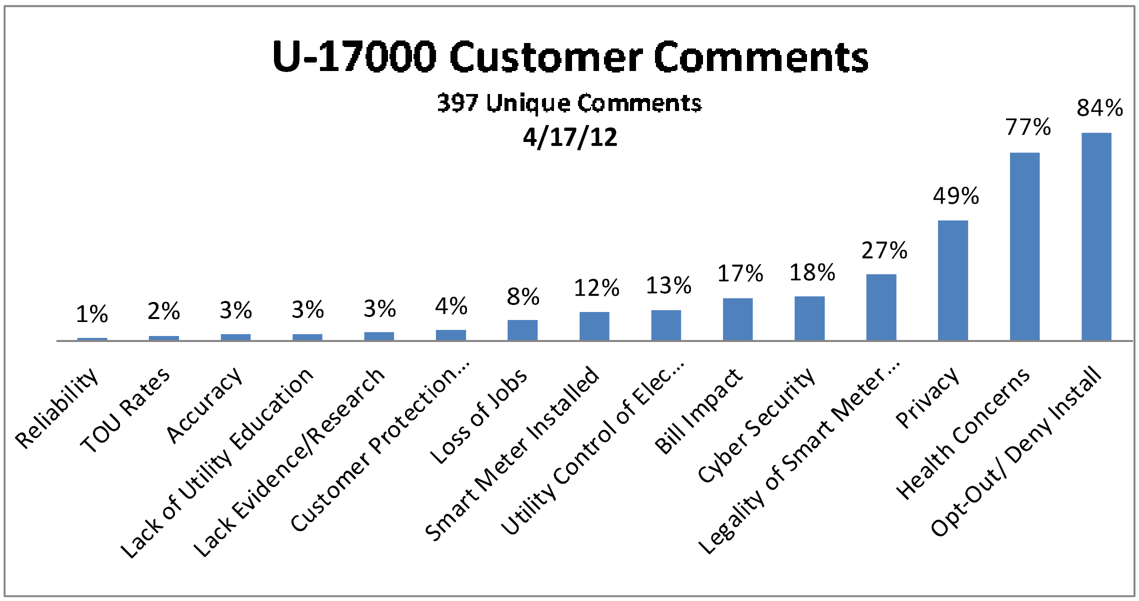
SUMMARY OF DOCKET FILINGS

The Staff logged 397 entries received from *unique parties* during the comment period. (Several people submitted multiple entries; however, these were counted as one comment for purposes of this report.) Three comments were received from non-Michigan residents.

Residential Customers

A number of topics were addressed in the comments. The dominant ones are shown in the chart below. Some customers addressed more than one topic in their submission. Of the customer commenters whose electric provider could be determined, the breakdown was: Detroit Edison (250), Consumers Energy (39), Cherryland Electric Cooperative (1), Clinton Board of Public Works (2), Indiana/Michigan Power Company (I&M) (4), Lansing Board of Water & Light (2), Upper Peninsula Power (4).

Chart 1: Residential Customer Comments



Reliability	TOU Rate	Accuracy	Lack of Education	Lack of Research	Customer Protection	Loss of Jobs	SM Installed	Utility Control of Power	Bill Impact	Cyber Security	Legality of SM Install	Privacy	Health	Opt-out/ Deny Install
4	9	10	11	13	17	32	46	50	69	71	106	193	304	334

Governmental Units

Seven resolutions were submitted by local governmental units:

- Townships of Harrison and Royal Oak,
- Villages of Almont and Grosse Pointe Shores,
- Cities of Farmington Hills and Madison Heights, and
- Macomb County Board of Commissioners.

Requested actions included: 1) further exploration into the health and safety of AMI meters, 2) delay/moratorium on further AMI installations until the Commission's review is completed, and 3) creation of an opt-out program for customers.

Although not formally submitted to the Case No. U-17000 docket, the Staff is aware of additional resolutions from other municipalities containing similar language to the resolutions filed in this docket.

Professional Organizations

Three professional organizations weighed in with submissions to the docket:

- American Academy of Environmental Medicine (AAEM) expresses concern with the levels of radio frequency (RF) radiation emitted by meters.
- Environmental Defense Fund (EDF) supports AMI deployment as a necessary element of grid modernization resulting in positive environmental impacts.
- TechNet also supports AMI deployment focusing on customer control of energy usage, data privacy and encouraging market innovation.

State of Michigan

A state agency and a state house representative filed comments:

- The Department of Attorney General asserts that smart meter benefits are not greater than the deployment costs for ratepayers.
- Representative Paul E. Opsommer states that filings for utilities with AMI meters were incomplete in the areas of meter function, cost and data privacy/protections.

Utilities

The order issued in Case No. U-17000 required utilities to provide specific information regarding smart meter deployment plans, investments, benefits, health and safety, data privacy, and opt-out options. The Commission received responses from investor-owned utilities (IOU) and Michigan electric cooperatives. Consumers Energy and Detroit Edison are the only Michigan utilities currently installing smart meters, so their responses are more thoroughly summarized.

Alpena Power plans to change to digital meters but does not intend to install smart meters. I&M has installed 10,000 AMI meters in South Bend, Indiana as a pilot. I&M has Automated Meter Reading (AMR)[3] at nearly all of its Michigan accounts and does not intend to replace those with smart meters. All of Northern States Power's Michigan customers have AMR, which send daily reads. Northern States

[3] Automated Meter Reading (AMR) "AMR technology allows utilities to read customer meters via short-range radio-frequency signals. These systems typically capture meter readings from the street using specially equipped vehicles." Massachusetts Institute of Technology, *The Future of the Electric Grid:* An Interdisciplinary MIT Study, 2011, p. 133. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf

Power does not intend to allow opt-out, but believes customers should pay for that option if an opt-out plan is required. Upper Peninsula Power uses electromechanical meters and is planning to continue this method**.** Wisconsin Electric Power Company (WEPCO) has installed AMR throughout its Michigan territory. WEPCO does not anticipate offering opt-out of AMR. Wisconsin Public Service Corporation has meters with both one and two-way communication. Its systems have been in place for over 10 years.

Alger Delta Cooperative, Cherryland Electric Cooperative, Cloverland Electric Cooperative, Great Lakes Energy Cooperative, HomeWorks Tri-county Cooperative, Midwest Energy Cooperative, Ontonagon County Rural Electrification Association, Presque Isle Electric & Gas Cooperative and Thumb Electric Cooperative filed a joint response and individual information. Most of the cooperatives have installed AMR that sends energy use data over power lines. Some of these meters have two-way communication. The cooperatives indicated they have experienced significant benefits from these meters. Presque Isle has a 10 meter AMI pilot. Cooperatives who have AMR do not intend to allow for opt-out.

Below are the responses from Consumers Energy and Detroit Edison regarding smart meter deployment plans as specified in the order in Case No. U-17000.

(1) The electric utility's existing plans for the deployment of smart meters in its service territory:

Consumers Energy Consumers Energy has completed Phase I of a four-phase pilot program, with the intention of full deployment by 2019 with 1.9 million total smart meters.
Detroit Edison Detroit Edison intends to install 2.6 million smart meters in a deployment plan that was initiated by a pilot in 2009. Detroit Edison currently has 650,000 meters installed and plans to have 1,000,000 installed by year end 2013.

(2) The estimated cost of deploying smart meters throughout its service territory and any sources of funding:

Consumers Energy The estimated cost is $750 million with no external funding (e.g., U.S. DOE ARRA grant); $398 million for smart meters and installation; $352 million for systems modifications, program management and other expenses.
Detroit Edison The estimated cost of smart meter deployment is $447 million for 2.6 million new electric meters, and the company received a U.S. DOE grant that reimbursed 50 percent of costs up to a pre-determined grant cap.

(3) An estimate of the savings to be achieved by the deployment of smart meters:

Consumers Energy Estimated savings over the anticipated 20-year life of the smart meters is $2 billion. Although benefits were described, no quantified breakdown of the savings total was provided.
Detroit Edison Detroit Edison estimates smart meter savings of $65 million per year, although this figure includes both electric and gas meters. Case No. U-16472, Exhibit A-18 was referenced for details.

(4) *An explanation of any other non-monetary benefits that might be realized from the deployment of smart meters:*

Consumers Energy Consumers Energy cited a U.S. DOE study (DOE/NETL-2010/1413) which summarizes the benefits tied to smart meter deployment. The study discusses societal benefits that include reduced outage times, as well as improvements in national security, environmental conditions, and economic growth.
Detroit Edison Proposed non-monetary benefits include an increase in customer satisfaction, the ability to identify voltage problems, new rate offerings, and the ability to expedite emergency disconnect response.

(5) *Any scientific information known to the electric utility that bears on the safety of the smart meters to be deployed by that utility:*

Consumers Energy Consumers Energy described its proposed system. No scientific information was provided.
Detroit Edison Detroit Edison provided a link to the report, *No Health Threat from Smart Meters*, Utilities Telecom Council, Q4 2010. The following studies were also included in an appendix:

Analysis of Radio Frequency Exposure Associated with Itron OpenWay® Communications Equipment, March 2011
Wireless Transmissions: An Examination of OpenWay® Smart Meter Transmissions in 24-Hour Duty Cycle, March 2011
Smart Meters and Smart Systems: A Metering Industry Perspective, Edison Electric Institute (EEI), Association of Edison Illuminating Companies (AEIC) and Utilities Telecom Council (UTC), March 2011
A Discussion of Smart Meters And RF Exposure Issues, Edison Electric Institute (EEI), Association of Edison Illuminating Companies (AEIC) and Utilities Telecom Council (UTC), March 2011

(6) *An explanation of the type of information that will be gathered by the electric utility through the use of smart meters:*

Consumers Energy The amount of kilowatt-hours (kWh) consumed each hour, kilovolts-ampere-reactive hours (kVARh) delivered, and actual voltage delivered will be collected every four-six hours. Some of this data is also added together and then sent once per day. Alarms and notification of field events will be sent out in real time.
Detroit Edison The data collected is accumulated Watt hour (Whr) consumption readings, load profile hourly interval watt-hour (Whr) and Volt Ampere hour (VAhr) energy data, load profile energy data, instantaneous voltage, meter messages, events, alarms, and network parameters. No customer-specific data such as addresses, phone numbers, account status or social security numbers will be gathered.

(7) *An explanation of the steps that the electric utility intends to take to safeguard the privacy of the customer information so gathered:*

Consumers Energy Safeguards for customer privacy include using data encryption and code division multiple access (CDMA). There is no personal customer information in the transmittal of data.

Detroit Edison Customer information is safeguarded through data encryption and internal confidentiality policies.

(8) *Whether the electric utility intends to allow customers to opt out of having a smart meter:*

Consumers Energy Consumers Energy proposes a future opt-out, but no details were provided.
Detroit Edison Detroit Edison is developing an opt-out for customers, but has yet to develop any details.

(9) *How the electric utility intends to recover the cost of an opt-out program if one will exist:*

Consumers Energy In accordance with utility cost of service principles, Consumers Energy suggests a future opt-out will be subject to a monthly maintenance fee. Fixed costs for opt-out would be recovered through a tariff-based, one-time charge and a monthly maintenance charge.
Detroit Edison Detroit Edison projects that customers choosing to opt-out will be responsible for all costs associated with an opt-out tariff provision.

Detroit Edison and Consumers Energy provided responses to the Commission's request in Case No. U-17000 regarding AMI deployment. The utilities could have provided additional details that would have been helpful for the Staff's analyses, including more specific information on savings calculations and privacy protections.

THE STAFF'S REVIEW OF AMI

The Staff reviewed the submitted comments, and the cited resources and literature provided by the electric utilities and the public. The Staff examined resources considered "technical" in nature. Many of these resources were published in reputable scientific or professional peer-reviewed journals or were based on reproducible, sound scientific methods and procedures. The Staff also examined many other resources and literature from a variety of sources. The Lawrence Berkeley National Laboratory (LBNL) document identifying resources was beneficial to the Staff in its review.[4] This report addresses some of the more frequently cited resources.

Safety and Health Concerns

The Federal Communications Commission (FCC) is charged with regulating international communications by radio, television, wire, satellite and cable within the United States and its territories. The FCC is responsible for providing licenses for RF emissions. The FCC regulations cover matters relating to public health and safety and have been designed to ensure that the levels of RF emissions that consumers are exposed to are not harmful.

[4] LBNL Website. http://smartresponse.lbl.gov/reports/sm-resourcelist041912.xlsx

In January 2011, the California Council on Science and Technology (CCST) completed a report titled *Health Impacts of Radio Frequency from Smart Meters*.[5] The CCST compiled a comprehensive overview of known information on human exposure to wireless signals, including the effectiveness of the FCC RF safety regulations. After evaluating numerous RF related publications and soliciting the opinions of technical experts in this and related fields, the CCST concluded that no additional standards are needed at this time and that FCC standards are adequate to ensure the health and safety of people from the known thermal effects of smart meters. The report also indicates that smart meters, when installed correctly and with FCC certification, emit only a fraction of the level that the FCC has determined to be safe.

In a recent report, *Radio-Frequency Exposure Levels from Smart Meters: A Case Study of One Model*,[6] the Electric Power Research Institute (EPRI) researched smart meter emission data that provides valuable insight into RF exposure scenarios for a widely used type of smart meter. There were three key findings: (1) exposure levels from individual meters declined rapidly as distance from the meter increased, (2) meters transmitted for only a small fraction of time, and (3) RF exposure levels remained well below the FCC exposure limits.

The Utilities Telecom Council (UTC), in an article titled *No Health Threat from Smart Meters*,[7] provided a review of the safety standards associated with RF emissions and stated that smart meters did not pose a health or safety threat. The UTC's research established that laptop computers using Wi-Fi transmit at levels similar to smart meters, although laptop transmitters are always "on" or transmitting and smart meters transmit for short intervals periodically throughout the day. After reviewing this and other common RF devices (cell phones, microwave ovens, etc.), the UTC concluded that the RF emissions from smart meters would not pose a threat to human health and safety.

The January 13, 2012, County of Santa Cruz Health Services Agency memorandum titled *Health Risks Associated with SmartMeters*[8] was drafted in response to the Santa Cruz County Board of Supervisors' request that the agency identify potential smart meter health effects and possible mitigation measures. The memorandum concluded that research addressing the health effects of electromagnetic fields (EMF) does not specifically address smart meters; there is no scientific data regarding non-thermal effects of smart meters; and government agencies should take precautionary avoidance measures. LBNL reviewed the agency's memorandum as part of the Smart Grid Technical Advisory Project.[9] LBNL's review focused on the objective of the memorandum, consistency of cited sources with agency established peer review criteria, and clarification of technical assumptions and claims. LBNL noted:

[5] *Health Impacts of Radio Frequency from Smart Meters*, January 2011. http://www.ccst.us/publications/2011/2011smartA.pdf
[6] *Radio-Frequency Exposure Levels from Smart Meters: A Case Study of One Model*, February 2011. https://www.nvenergy.com/NVEnergize/documents/EPRI_1022270_caseStudy.pdf
[7] *No Health Threat From Smart Meters*, Fourth Quarter 2010 Issue of the UTC JOURNAL. http://www.utc.org/utc/no-health-threat-smart-meters-says-latest-utc-study
[8] County of Santa Cruz, *Health Risks Associated with SmartMeters*, http://emfsafetynetwork.org/wp-content/uploads/2009/11/Health-Risks-Associated-With-SmartMeters.pdf
[9] The Smart Grid Technical Advisory Project provides technical assistance and training to state regulatory commissions on topics related to smart grid. The Smart Grid Technical Advisory Project does not participate in litigated or contested regulatory or other proceedings.

> [T]he Agency memorandum does not appear to provide a balanced representation of research, the risks, or mitigation options. Instead the Agency memorandum is largely focused on scientifically unsupported claims related to "electromagnetic hypersensitivity" (EHS).

Individuals with EHS report real symptoms; however, health research has been unable to consistently attribute those symptoms to EMF exposure.[10] LBNL's review of the Santa Cruz memorandum highlighted concerns with the methodology of the agency memorandum cited sources.[11]

On April 12, 2012, the AAEM submitted their position paper, *Electromagnetic and Radiofrequency Fields Effect on Human Health*, to Case No. U-17000.[12] The paper supports AAEM's position that emissions from smart meters are potentially harmful. LBNL also provided a response to the AAEM position paper. LBNL's primary concerns with the paper's findings are a) the research used to establish a cause and effect relationship does not address smart meters, b) the research citations and references are unrelated to smart meters, c) conclusions are about EHS, and d) the minimal amount of RF smart meters actually contribute to total environmental RF. LBNL explains that RF is distinguished by a number of characteristics including frequency, intensity and proximity.[13] There are multiple sources of RF exposure in our everyday environment such as cellular phones, wireless devices such as laptops and routers, microwave ovens, baby monitors, garage door openers, "walkie talkies," computer monitors, fluorescent lighting, and electrical wires within the home.[14] [15] Smart meters are a small contributor to the total environmental RF emissions to which the general public is exposed. Eliminating smart meters would result in a minimal reduction of total emissions.[16]

Several comments submitted in Case No. U-17000 cited the World Health Organization's (WHO) classification of RF EMF as a class 2B carcinogen in support of their smart meter health concerns. This classification means that RF EMF has been deemed as *possibly* carcinogenic to humans.[17] RF EMF was designated as a class 2B carcinogen due to limited evidence associating glioma and acoustic neuroma, two types of brain cancer, with wireless telephone users. The Staff was unable to identify research that associates AMI meters with any type of cancer.

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[10] LBNL, *Review of the January 13, 2012 County of Santa Cruz Health Services Agency memorandum: Health Risks Associated with Smart Meters* http://smartresponse.lbl.gov/reports/schd041312.pdf

[11] LBNL, *et al*. http://smartresponse.lbl.gov/reports/schd041312.pdf

[12] American Academy of Environmental Medicine, *Electromagnetic and Radiofrequency Fields Effect on Human Health*. http://efile.mpsc.state.mi.us/efile/docs/17000/0391.pdf

[13] LBNL, *Review of the April 12, 2012 American Academy of Environmental Medicine (AAEM) submittal to the Michigan Public Service Commission*, http://smartresponse.lbl.gov/reports/aaem041812.pdf

[14] Federal Communications Commission: *Radio Frequency Safety* http://transition.fcc.gov/oet/rfsafety/rf-faqs.html.

[15] Federal Communication Commission: *Interference – Defining the Source* http://www.fcc.gov/guides/interference-defining-source.

[16] City of Naperville, Naperville Smart Grid Initiative (NSGI), Pilot 2 RF Emissions Testing – Summary Report-V2.0, *Smart Meters, Household Equipment, and the General Environment*, November 10, 2011. http://www.naperville.il.us/emplibrary/Smart_Grid/Pilot2-RFEmissionsTesting-SummaryReport.pdf

[17] International Agency for Research on Cancer, *IARC Monographs on the Evaluation of Carcinogenic Risks to Humans*, January 2006. http://monographs.iarc.fr/ENG/Preamble/currentb6evalrationale0706.php

In May 2011, members of the WHO's International Agency for Research on Cancer's (IARC) Monographs Working Group reviewed roughly 900 studies that involved RF EMF and cancer.[18] The group categorized the studies by the following RF EMF sources: occupational exposure (i.e., radar installations), personal exposure associated with the use of wireless telephones, and environmental exposure (i.e., radio/television signals). For occupational exposure to RF EMF, the group determined that there are "some positive but inconsistent signals." With respect to environmental sources of RF EMF, the group determined that there was no "solid data" to conclude a link between cancer and RF EMF exposure. Lastly, regarding personal exposure, the group found there to be limited evidence linking glioma and acoustic neuroma to wireless phone use, with inadequate evidence for other cancer types.

Experts in the field of RF EMF have testified in front of public utility commissions outside of Michigan as to how the IARC classification correlates with smart meter technology. For example, Baltimore Gas & Electric provided the expert opinion of Dr. Peter Valberg to the Public Service Commission of Maryland, who testified on how the category 2B classification of RF EMF should be interpreted. Dr. Valberg stated that the IARC has not found any ". . . adverse health consequences established from exposure to RF fields at levels below the international guidelines on exposure limits published by the International Commission on Non-Ionizing Radiation Protection."[19] He goes on to state that the 2B classification of RF EMF was ". . . made with reference to the quantity of exposure, *e.g.*, no quantitative estimate as to how various uses of RF contribute to human exposure. . . ."[20] and that ". . . smart meters constitute one of the weakest sources of our RF exposure."

Dr. Yakov Shkolnikov and Dr. William H. Bailey, engineers from the consulting firm Exponent, provided expert testimony to the Public Utility Commission of Nevada concerning NV Energy's smart meter deployment, and addressed smart meter RF EMF emission concerns. These witnesses pointed out that although RF EMF was classified in group 2B ". . . the evidence is limited that cancer develops from exposures from RF fields."[21] They also make it clear that ". . . the indications of potential risk derive almost entirely from statistical associations in some studies between the use of mobile phones and certain types of cancer."[22]

The WHO's decision to classify RF EMF in the group 2B category was based on studies involving wireless phones, not smart meters. While both wireless phones and smart meters emit RF EMF, the

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[18] International Agency for Research on Cancer, *Radiofrequency Electromagnetic Fields: evaluation of cancer hazards*. http://monographs.iarc.fr/ENG/Publications/REF_Poster2012.ppt

[19] *In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Meter Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost*, Case No. 9208, Comments on an "Opt-Out" Option for Smart Meters, Testimony of Dr. Peter A. Valberg, April 6, 2012. http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new1.cfm?CaseNumber=9208

[20] *In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Meter Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost, et al.*

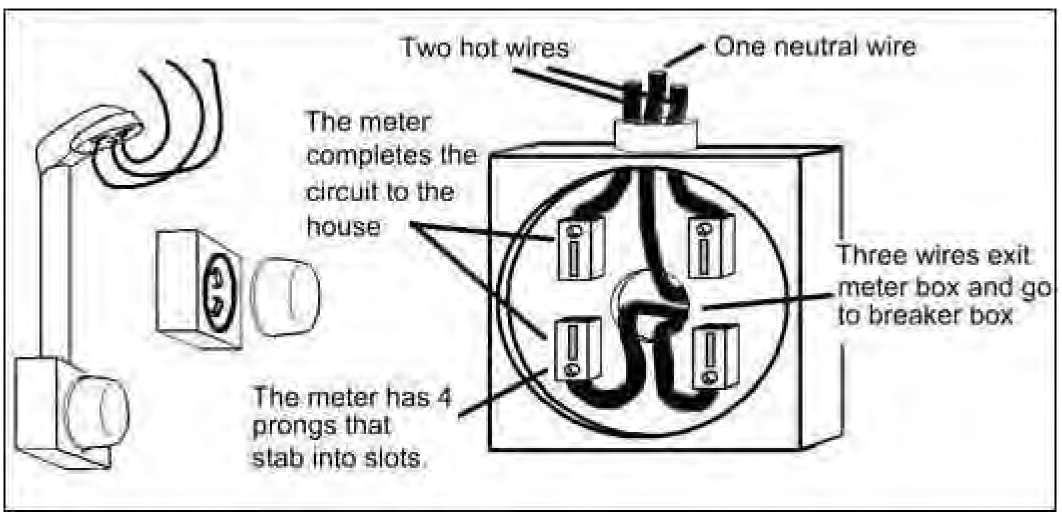
[21] *Investigation regarding NV Energy's Advanced Service Delivery Meter Program a/k/a Smart Meter and its implementation*, Docket No. 11-10007, Comment of S. Stirling, December 22, 2011.

[22] *Investigation regarding NV Energy's Advanced Service Delivery Meter Program a/k/a Smart Meter and its implementation, et al*

major difference between the two is the lower level of exposure to frequencies from smart meters. Low exposure levels from smart meters coupled with the fact that the IARC's classification is based on weak mechanistic evidence and limited evidence derived from different RF EMF emitting devices is important to consider when evaluating the substance of the group 2B classification. After careful review of the available literature and studies, the Staff believes that the health risk from the installation and operation of metering systems using radio transmitters is insignificant. In addition, the appropriate federal health and safety regulations provide assurance that smart meters represent a safe technology.

Some public comments stated a link between smart meters and house fires. Meter fires for any type of meter are a rare occurrence, according to the National Fire Protection Agency's 2012 annual report[23] on home electrical fires. This type of fire makes up only 1% of the average reported cause of home electrical fires. Factors associated with meter fires are not exclusive to smart meters but apply to all meters. Installation details for smart meters and electromechanical meters are the same. Both meter types have four prongs on the back. The four prongs attach to four slots known as stabs. These stabs, along with the wires from the power lines and meter itself, are housed inside a protective case known as a meter box. Once the meter is connected, the electrical circuit is complete. This is shown in the diagram below. Component failure (i.e. loose stab connection) can cause arcing, potentially resulting in a meter fire. It is the component failure, not the meter unit that is the cause of an arcing-induced fire.

Figure 1: Meter Connection



[23] *Home Electrical Fires*, National Fire Protection Association, January 2012. http://www.nfpa.org/assets/files//PDF/OS.electrical.pdf

Data Privacy

As smart meter deployments have become more prevalent throughout the United States, customer data privacy has become a priority issue. In order to address the concerns of the public regarding smart meter data privacy, multiple entities have engaged in efforts to identify and address the fundamental privacy issues. The Staff reviewed data privacy literature that specifically addressed or were clearly applicable to concerns arising from smart meters collection of customer electric usage information. Documents reviewed originated from the following entities: municipal utilities, state utility commissions, state legislation, standard development organizations, federal government and academia. The following table lists the literature reviewed in preparation of this section.[24]

Table 1: Data Privacy Policies

Entity:	***Document Name:***
Municipal Utilities	
City of Naperville	**Naperville Smart Grid Initiative Customer Bill of Rights**
State Utility Commissions	
State of California	**Privacy Protections For Energy Consumption Data**
State of Colorado	**Rules Regulating Electric Utilities**
State of New York	**Smart Grid Policy Statement**
State of Texas	**Customer Protection Rules For Retail Electric Service**
State Legislation	
State of Arizona	**Consumer Protections; Rules; Confidentiality; Unlawful Practice**
State of Oklahoma	**Electric Usage Data Protection Act**
State of Washington	**WAC 480-100-153 Disclosure of Private Information**
Standards Development Organizations	
NAESB	**Third Party Access To Smart Meter-Based Information**
NISTIR 7628	**Guidelines for Smart Grid Cyber Security**
Federal Government	
US Dept. of Energy	**Smart Grid Privacy Workshop Summary Report**
US Dept. of Homeland	**Fair Information Practice Principles**
Academia	
Vermont Law School	**A Model Privacy Policy for Smart Meter Data**

AMI necessitates a higher volume of data collected by utilities, therefore it is imperative that customer information be properly protected through appropriate regulations. Federal legislation protecting consumer data privacy is forthcoming;[25] however, it is important to identify ways to protect Michigan's ratepayers in the interim. States that feature more advanced AMI deployment such as California,

[24] Links to the table documents can be found in Appendix A.
[25] *U.S. Department of Energy Smart Grid Privacy Workshop Summary Report*.
http://www.smartgrid.gov/sites/default/files/doc/files/Privacy%20report%202012_03_19%20Final.pdf

Colorado, Texas, Arizona, Oklahoma, and Washington have addressed customer data protection through state legislation or administrative rules adopted by the public utilities commissions. The Staff acknowledges that interim protections could be achieved through the development of utility tariffs that address customer data privacy. The Staff recommends including the following fundamental concepts when addressing privacy policy:

- Definitions of various types of data collected *(usage/billing, aggregate, customer identifiable),*
- Permitted usage of data types by utility *(sales, contractor work, emergency),*
- Customer consent and third-party disclosure rules *(notice, timeframe, records),*
- Availability of usage information to customer *(web portal, direct mail, email),*and
- Privacy breach requirements *(notification to customer/commission).*

The Staff recommends that there be further investigation into the most appropriate manner (administrative rules, legislation, tariffs, etc.) to ensure customer privacy. This process should include all relevant stakeholders. In the interim, the Staff recommends that utility tariffs include provisions to enhance customer privacy.

Cyber Security

As Michigan transitions to a more technologically advanced power grid, it is important that the proper actions are taken by utilities to address cyber security threats. Cyber security planning is defined as preventing damage to, unauthorized use of, or exploitation of electronic information and communications systems and the information contained therein to ensure confidentiality, integrity, and availability.[26] The attention cyber security has received at the national and state levels for many years indicates that utilities, regulators and consumers all share common concerns. Improving the electrical grid involves gathering more data and utilizing more technology. With every added piece of technology, the risk of vulnerabilities inherently increases. The U.S. DOE has stated that the smart grid of the future should be secure and resilient against all forms of attacks. A smarter grid includes more devices and connections that may become avenues for intrusions, error-caused disruptions, malicious attacks, destruction, and other threats.[27]

It is important to balance the need for a more digitally connected grid and the inherent risks of these new technologies and their interconnection. At the national level, several organizations are currently addressing this issue: North American Electric Reliability Corporation (NERC), National Institute of Standards and Technologies (NIST), Smart Grid Interoperability Panel Cyber Security Working Group (CSWG), National Electric Sector Cybersecurity Organization (NESCO), and the U.S. DOE. These

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[26] National Association of State Energy Officials (NASEO), *Smart Grid and Cyber Security for Energy Assurance*. http://www.naseo.org/energyassurance/NASEO_Smart_Grid_and_Cyber_Security_for_Energy_Assurance_rev_November_2011.pdf

[27] Executive Office of the President, National Science and Technology Council, *A Policy Framework For The 21st Century Grid: Enabling Our Secure Energy Future*, June 2011. http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf

groups have published reports and compliance programs to provide utilities guidance on cyber security in the electric industry.

The overall goal is to develop a framework that ensures effective cyber security is appropriately implemented and that all stakeholders contribute to the security and reliability of the electrical grid.[28] The goal is not a compliance-based culture in which companies are expected to stand alone in this effort. Instead it should be a proactive, responsible and collaborative culture in the state of Michigan. The Staff reviewed multiple cyber security related documents published by the leading cyber security associations and found the following commonalities:

- Cyber security efforts should concentrate on rigorous open standards and guidelines through public-private partnerships for security,
- Effective cyber security will rely on data sharing and cooperation between regulatory, private and electric industry entities,
- A risk-based approach to cyber security planning should be implemented,
- A cyber security performance accountability system should be created to fulfill risk-based planning, and
- Regulatory bodies should be in constant contact with asset owners regarding cyber security.

Several states have taken positions on cyber security including California and Texas. The Public Utility Commission of Texas enacted a cyber security rule requiring electric utilities to have an independent security audit of the mechanism for customer and Retail Electric Provider (REP) access to meter data conducted within one year of initiating such access and promptly report the results to the commission.[29]

The Federal Trade Commission (FTC) has studied how entities collect and use personal information. They have compiled their findings in the Fair Information Practices (FIP), which has been used successfully across many industries. The California Public Utilities Commission (CPUC) cited the FIP as a proven model for data security that the electric industry should utilize. In regards to cyber security, the CPUC stated upon any breach[30] affecting 1000 or more customers, an electric provider has two weeks to notify a commission appointed cyber security representative.[31] They also required IOU's to file a year-end cyber security breach report with the cyber security representative at the commission.[32]

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[28] Executive Office of the President, *et al.*
http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf
[29] Public Utility Commission of Texas, Electric Substantive Rules.
http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/Electric.aspx
[30] A breach is any unauthorized use or exploitation of customer information.
[31] Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of Smart Grid, *et al.*
[32] Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of Smart Grid, *et al.*

The Staff proposes that the following cyber security measures be implemented in Michigan:

- Each utility should adopt an annual independent security audit of the mechanisms of customer access, third party access and internal cyber risk-management practices. The independent auditor should be approved by the Staff.
- As outlined in the National Association of Regulatory Utility Commissioners' (NARUC) resolution regarding cyber security, the Staff should maintain a dialogue with regulated utilities to ensure that they are in compliance with standards, and that preparedness measures are employed to deter, detect and respond to cyber attacks and to mitigate and recover from them.[33]
- Utilities should adopt the same breach notification policies as other states have adopted, namely the notification of any breach affecting 1000 or more customers within two weeks of the breach.
- Each utility should be required to file a yearly breach notification summary with the Staff, detailing all breaches of customer information, including any third party breach information.

Customer Education

Customer education and participation is an important component of the successful implementation of the smart grid. A portion of the smart meter benefits rely upon customer engagement. To facilitate customer engagement, utilities must provide customers with clear and accurate information about programs and services available both prior to and *throughout* the deployment of smart meters.[34] Within the 397 unique comments submitted to Case No. U-17000, 360 comments reference a lack of communication with customers about the functionality and benefits of smart meters.[35] As the Maryland Public Service Commission[36] stated:

> The negative experiences in other states . . . illustrate vividly that poor customer education will magnify small-scale problems and create disproportionate customer skepticism and unhappiness.

For this reason, the Staff reviewed customer education efforts in various states. Several states have supported the importance of customer education through both legislation and orders.

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[33] NARUC, *Resolution Regarding Cybersecurity*, February 17, 2010. http://www.naruc.org/Resolutions/Resolution%20on%20Cybersecurity1.pdf
[34] Massachusetts Institute of Technology, *The Future of the Electric Grid*; An Interdisciplinary MIT Study, 2011, p. 164. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf
[35] Pg. 4, Chart 1 of this report (combined categories of lack of education, utility control of power, legality of smart meter install and privacy).
[36] *In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy Smart Meter Initiative and to Establish a Surcharge Mechanism for the Recover of Cost*, Case No. 9208, Order No. 83531, pp. 42-43. http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new1.cfm?CaseNumber=9208

- Colorado Public Utilities Commission concluded that utilities should submit a smart meter plan with a detailed customer education and outreach plan.[37]
- Nevada Public Utilities Commission concluded that NV Energy should enhance its consumer outreach efforts. The outreach efforts were to include a "media plan leading up to the deployment of smart meters that will frequently reach out into the community and use multiple channels to reach customers more effectively."[38]
- California Public Utility Commission (CPUC) was directed by California Public Utilities Code § 8360 (2009), to identify criteria to ensure that the utility smart grid deployment plans conform to best practices. Commission Rulemaking R 08-12-009 identifies the need for a smart grid strategy recognizing that customer participation is necessary for the demand-side benefits.[39] In addition, CPUC Decision 12-04-025 identifies metrics to use to track customer participation.[40]
- The Maryland Public Service Commission directly addressed customer education in Case No. 9208, Order No. 83531. The commission order states "[t]hat Baltimore Gas and Electric Company shall submit, for the Commission's approval, the Company's updated customer education plan and associated proposed messaging that it will provide customers prior to and during installation of the meters, before Peak Time Rebates begin, and before any other programmatic changes take effect. Baltimore Gas and Electric and other parties in the matter shall develop, and submit for Commission approval, a comprehensive set of metrics by which the Commission may measure the effectiveness of the customer education plan, . . ."[41]
- The Public Utility Commission of Texas met regularly with utilities to help develop radio ads, door hangers, billboards, etc. which were used to educate the public about smart meters. The education effort specifically targeted smart meter cost recovery, deployment, and implementation. The Texas Public Utility Commission also approved each utility's budget associated with smart meter customer education[42].
- Maine Public Utility Commission ordered Central Maine Power to ". . . develop and implement a customer communication plan that will explain the various opt-out options, describe the benefits of the AMI program, describe the functionality of the available meter options, describe the

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[37] *In the Matter of the Investigation of the Issues Related to Smart Grid and Advanced Metering Technologies*, Docket No. 10I-099EG. Decision No. C11-0406, Order State Conclusions and Next Step, March 30, 2011, p. 5.
[38] *Investigation regarding NV Energy's Advanced Service Delivery Program a/k/a Smart Meters and its implementation*, Docket No. 11-10007, Interim Order, January 11, 2012, p. 8.
[39] California Public Utility Commission, R 08-12-009.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119902-02.htm#P201_29007
[40] California Public Utility Commission, Decision 12-04-025, April 24, 2012.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/164808.htm
[41] *In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*, Case No. 9208, Order No. 83531, p. 50.
http://webapp.psc.state.md.us/Intranet/sitesearch/CN9208.pdf.
[42] Relevant Dockets include: Oncor Docket No. 35718, CenterPoint Docket No. 35639, AEP TX Docket No. 36928, TNMP Docket No. 38306.
http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/filings/pgSearch.asp.

charges associated with the opt-out, and describe the process by which a customer may opt-out."[43]

- In 2008, the Ohio legislature enacted changes to the Ohio Revised Code – Title XLIX Public Utilities which required utilities file a customer education plan; the purpose of which is to ". . . educated [*sic*] Ohio's consumers about their new choices for electric service."[44]

The transition to smart meters and related infrastructure will provide customers access to current data about their energy usage, creating an opportunity to better control energy consumption. Smart meters also provide the basic infrastructure for aggregate benefits related to reliability, outage identification, and reduced peak demand. These benefits have a positive effect on all customers including those who choose to opt-out.[45] A smooth transition to smart meters can be accomplished only through customer education. A well thought out education strategy allows customers to develop a sense of trust with the utility and an understanding of the available benefits.

The Staff recommends utilities develop and implement a new education strategy similar to those used in other jurisdictions. Education program results should reflect high levels of customer engagement, acceptance and enthusiasm with their smart meter program. The strategy should include metrics to measure the overall effectiveness of the education program.

National Policy

The United States Congress has passed several laws that support the upgrade of the electric grid, including deployment of smart meters for residential and other types of customers. These laws have provided a framework for smart grid, including smart meter deployment in the United States. Basically, these laws encourage states to proceed with modernizing the electric grid in order to be ready for the electric demands of the 21st Century.

The Energy Policy Act of 2005 (EPAct 2005) was the first piece of federal legislation that discussed smart grid. The statute strongly encourages demand response. It calls upon utilities to offer time-based rates with a time-of-use meter to all customer classes. It also requests that state public utility commissions investigate the installation in their state of time-of-use meters and communication devices to enable time-based pricing rate schedules and other demand response programs. The statute also mandates that, by October 2012, all federal buildings be individually metered for electricity consumption and, to the extent feasible, use advanced meters that measure energy use on an hourly basis.[46]

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[43] Maine Public Utilities Commission, Docket No. 2010-345, Order (Part I), May 19, 2011, p. 2.
[44] *In the Matter of the Commission's Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Revised Code*, Case No. 99-1141-EL-ORD, Entry, June 8, 2000. http://www.puco.ohio.gov/emplibrary/files/docketing/ORDERS/2000/0604/99-1141.pdf
[45] Electric Power Research Institute *Advanced Metering Infrastructure*, February, 2007, p. 1. http://www.ferc.gov/eventcalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf
[46] Energy Policy Act of 2005, Pub. L. No. 109-58, 100 Stat. 567 (codified at 1 U.S.C. §§ 900-999).

The Energy Independence and Security Act of 2007 (EISA) is a major piece of federal legislation addressing smart grid and smart meters. Title XIII, Sections 1301 through 1309 supports modernizing the nation's electric grid and contains provisions giving the U.S. DOE a leadership role in all but two areas of smart grid advancement. Interoperability was assigned to the NIST and the Federal Energy Regulatory Commission (FERC), and recovery of smart grid investment was relegated to the state public service commissions. The statute contains a policy statement on United States' grid modernization that defines "smart grid;" establishes the Smart Grid Advisory Committee, the Smart Grid Task Force, and the Smart Grid Interoperability Framework; and institutes the Smart Grid Investment Matching Grant Program, which provides a 20% match for qualifying smart grid investments.[47]

The American Recovery and Reinvestment Act of 2009 (ARRA) amends EISA allowing U.S. DOE to provide financial support for smart grid demonstration projects and advanced grid technology investments, such as AMI. In total, the legislation provides $3.4 billion in funding for numerous smart grid projects across the nation, including smart meters, in-home energy management displays, smart thermostats, advanced transformers and load management equipment. The act establishes a smart grid information clearinghouse and requires that demonstration projects use open protocols and standards.[48]

In addition to federal laws, numerous prestigious agencies and institutions have considered the national outlook for the smart grid and indicate that installing smart grid technologies, including smart meters, will have a positive benefit on the United States' electric grid. These reports urge the United States to follow the directives of the federal law and update the electric grid.

In 2012, the U.S. DOE issued the 2010 Smart Grid System Report. The report, required by the EISA, outlines the current status of smart grid development, projects its future, and identifies obstacles to its progress. It describes the scope of smart grid, recognizes its stakeholders, and makes recommendations for future reports. The report states that recent progress has been significant due to funding from ARRA of 2009, including the provision of $812.6 million in federal grant awards for AMI deployments throughout the United States, the implementation or expansion of distributed resource interconnection policies in 14 states since 2008, and funding the deployment of 877 phasor measurement units. The report determines that correctly assessing the value proposition and obtaining capital for new technologies that communicate information between electricity sector participants are challenges that need to be overcome in order to continue development of the smart grid.[49]

Several NARUC initiatives support smart grid activities. NARUC and FERC have established the Smart Response Collaborative which provides a forum for federal and state regulators to share information about the smart grid to support the development of better and more effective policies. NARUC has also passed resolutions that address smart grid. A resolution passed on July 20, 2011, endorsed a foundational

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[47] Energy Independence and Security Act of 2007 (EISA), Pub. L. No. 110-140, 121 Stat. 1492, 1783-84 (codified at 42 U.S.C. § 17381).
[48] American Recovery and Reinvestment Act of 2009 (ARRA), Pub. L. No. 111-5, 123 Stat. 115, 516.).
[49] *U.S. DOE 2010 Smart Grid System Report*, Report to Congress, Washington DC, February 2012. http://energy.gov/oe/downloads/2010-smart-grid-system-report-february-2012

set of principles related to advance metering and smart grid deployments. The principles encourage the continued installation of smart grid technologies including AMI, while also advising utility commissions to continue to assess the best strategies for their states.[50]

The Future of the Electric Grid was published by the Massachusetts Institute of Technology (MIT), the sixth in a series of reports that examine the "future of" energy and environmental issues. The report provides a snapshot of the current status of the United States' electric grid and a vision for the evolution of the grid over the next two decades. The study group, consisting of MIT professors and research assistants, with input from industry and government experts, reviewed and evaluated existing research and made recommendations that will help to ensure the future of the electric grid. One of the main findings is that regulatory policies and the technologies used to support the grid must change or it is likely to be difficult to maintain acceptable reliability and reasonable electric rates. An updated distribution system with the use of AMI is instrumental to a smarter grid. The study identifies the benefits of AMI including a reduced cost of meter reading, more accurate and timely billing, improved customer support, enhanced distribution monitoring and management, support for demand response and energy conservation, quicker response to outages and reduced outage times. With the decreasing availability of electromechanical meters, AMI will soon be the most viable metering option available to utilities. The study acknowledges that there have been health concerns raised by customers, but concludes that the scientific research does not suggest that radio waves from smart meters have adverse health effects. They acknowledge that utilities may have to consider these concerns when designing their programs by inclusion of opt-out or other provisions.

The study also reviewed the status of cyber security readiness on the United States' grid. The report recommends a heightened focus on detection, response, and recovery strategies, especially for the distribution system. Since there is currently more than one agency working on this issue, a single agency should be given responsibility to develop and enforce standards across the entire electric power system.[51]

A Policy Framework for the 21st Century was issued by the federal government to build on the policy directives set forth in the EISA and the ARRA by creating a pathway to a modernized grid. A smarter, modernized and expanded grid is pivotal to the United States, playing a lead role in a clean energy future. The electric grid in the United States is at an advanced age. This makes it imperative to upgrade the grid in three categories: advanced information and communication technologies that improve transmission and distribution; advanced metering; and equipment that accesses and leverages energy usage information. The study concludes that AMI can empower consumers to better manage their energy usage and reduce their energy bills.

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[50] National Association of Regulatory Utility Commissioners, Smart Grid Resources. www.naruc.org/smartgrid/

[51] Massachusetts Institute of Technology, *The Future of the Electric Grid*, An Interdisciplinary MIT Study, 2011. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf

Ensuring the privacy of energy use data is also of primary concern to the study participants. Existing agencies, such as state public service commissions, may be able to set privacy rules for regulated utilities. The FTC's FIP principles can provide a framework for developing codes of conduct to protect this data.[52]

Policies and Practices

AMI has the potential to provide increased electric reliability while providing customers with the information and choices necessary to reduce or shift their electric consumption. Customers can only realize these benefits if utilities begin to collect more detailed usage data. While AMI does not transmit personal customer information, it does gather usage data more frequently than a traditional meter. Although utilities have been protecting customer data for many years, the collection, storage, use, access, and disclosure of customer consumption data have generated concerns about privacy, utility transparency, customer choice, and security. Attention to system reliability standards, electric technical standards and utility billing practices are warranted when addressing customer protection, data collection, customer privacy, cyber security, and system reliability benefits.

Several areas of current rules and tariffs will be affected by AMI deployment in Michigan. In some cases, the topic of concern is not a direct result of AMI. One example is privacy. Customers are more sensitive to privacy with the deployment of AMI, but the requirement for documented and clearly communicated utility privacy policies existed prior to AMI deployment. Consistently documenting privacy policies creates transparency and accountability as new technologies continue to evolve.

Electric utilities regulated by the Commission follow rules and standards for electric service set forth in administrative rules, tariffs, and Commission orders. All of these regulatory mechanisms should be considered and the most effective chosen to ensure customers have adequate protections.

The Staff conducted a preliminary investigation into national recommendations, rules from other states, and utility best practices. This investigation revealed Michigan's current policies are in need of review in order to address on-going customer issues.[53] Michigan should consider the following areas as the utility systems and utility/customer relationships change due to AMI.

- Customer Consent – Customers should have the option to authorize data collection and services not related to core billing and operational services.
- Individual Access and Participation – Customers should have easy, timely access to their detailed usage data in a standard downloadable format.
- Customer Choice –Utilities should clearly, fully, and accurately describe all choices available to customers.
- Notice and Purpose – Utilities should provide a detailed description of all purposes for which customer data will be used.

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[52] *A Policy Framework for the 21st Century: Enabling Our Secure Energy Future, et al*
http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf
[53] A complete list of research sources is available in Appendix A

- Collection and Scope – Only information that is required to fulfill the stated purpose specified under Notice and Purpose should be collected.
- Security – Personal information in all forms should be protected from loss, theft, unauthorized access, inappropriate disclosure, copying, use, or modification. Utilities should implement breach notification policies and independent third party privacy and security audits.
- Management and Accountability – Utilities should develop and appoint personnel to ensure that information security, privacy policies, and privacy practices exist and are followed, including ongoing training and audits.
- Utility Processes – Utilities should provide a process for individuals to see and easily correct inaccuracies in their information. Utilities should estimate customer bills only if they are able to demonstrate that there was an unavoidable circumstance. Prepayment is an option that may be preferred by some customers.
- Meter Accuracy – Standards that ensure the accuracy of AMI meters should be developed.
- Service Reliability – Performance measures should reflect system reliability and outage support provided through AMI implementation.

The Staff examined current Commission rules and technical standards and found that some AMI related areas are not covered. For example, there is no definition for AMI. There are, however, current rules that address AMI capabilities such as remote shutoff (2007 AACS R 460.142). In a larger review of methodologies, rules and standards should be evaluated further.

It is recommended that all stakeholders work to analyze and identify the most appropriate implementation methods for addressing the policy considerations listed above. Stakeholders should routinely review all policies related to smart grid as smart grid technologies continue to develop.

Smart Grid Vision

When considering the deployment of AMI in Michigan, it is important to recognize that smart meters and their supporting communications infrastructure represent a single component of a fully modernized grid. AMI introduces a communications platform that can support a multitude of smart grid applications resulting in improved efficiency and reliability, as well as increased longevity of Michigan's aging electric infrastructure. When properly designed and implemented, AMI presents a unique opportunity for Michigan ratepayers to take control of their energy consumption and their energy bills.

The smart grid will enhance electric service in Michigan. Real time outage identification, through AMI, will result in a quicker response to outage situations. Areas without service can be identified almost immediately and individual customers who are still out after their neighborhood has been restored will be easily located. The smart grid technologies will reduce operations and maintenance costs, primarily through reduced meter reading costs, more accurate billing, reduced outage time and monitoring tools that help the utility anticipate equipment failure. AMI meters, with the use of dynamic and time-of-use rates, can reduce peak demand and increase energy conservation. The result could curtail the need for future capital investment in electrical system capacity and lead to other grid efficiencies. This would result in lower capital costs for all ratepayers.

A Michigan smart grid vision should provide direction to implement technology that will enhance the functionality of the electric grid. It is difficult to have all utilities, vendors, regulators and customers share a succinct vision of what the future electric grid will look like. Therefore, it is important to identify electric grid "objectives" that outline a more reliable grid, improve power quality and incorporate cleaner power sources for electricity generation. All components of electric grid improvements, including AMI installation, distribution infrastructure replacement, and electric generation should reflect the larger objectives of a smart grid vision.

The Staff proposes that future smart grid investments from utilities must correlate with the following objectives aimed at delivering transparent and identifiable benefits to ratepayers:

- Accommodate advanced generation and storage options
- Enable informed participation by all customers
- Support new products, services, and markets
- Optimize existing assets, increase efficiency and improve reliability
- Operate resiliently against physical and cyber attacks

Michigan's current electric grid is characterized by centralized fossil fuel generation plants delivering electricity over long distances to meet customer needs. This model has been dominant for over a century and has provided an economical and reliable means of providing energy to Michigan citizens. However, increased investment and technological advances in decentralized generation and storage options such as gas turbines, diesel engines, solar photovoltaic, wind turbines, biomass generators and plug-in electric vehicles present potential generation options in the future. The Staff supports future grid investments that promote a more flexible grid that is capable of integrating any and all generation, two-way power flows and storage options. These investments will help ensure that Michigan ratepayers have access to the most cost effective generation in the future.

The traditional relationship that has existed between the utility and its ratepayers was limited to customers consuming energy and then receiving a monthly bill for the service. As the smart grid takes form in Michigan, the Staff envisions a much more interactive relationship developing between utility and customer. Utilities need to develop communications avenues and program incentives capable of informing, engaging, empowering, and motivating customers to change their behavior. The Staff believes that an extensive customer education campaign that coincides with technology deployment is pivotal to a successful implementation strategy. The Staff also believes that in the future, piloting a variety of customer programs (dynamic rates, prepay, demand response) to measure their effectiveness will be key to realizing the full spectrum of utility and customer benefits.

Consistent standards are necessary for new products, services and markets to be successful. Effective implementation of a smart grid in Michigan will bring an abundance of new products, services, and markets that accommodate a variety of customer needs. Michigan customers should have access to the full potential of these innovations. For this reason, smart grid deployment in Michigan should be standards based. Nationally and globally recognized standards play a critical role in the ongoing development of these products, services and markets. The development and adoption of smart grid standards can help investments made today remain valuable into the future, remove barriers to innovation, maximize customer choice, create economies of scale, emphasize best practices, and open global markets. A standard based framework will promote interoperability and accommodate advances in technology.

The two-way flow of system information made possible by the implementation of AMI has multiple applications outside of metering. In the future, the Staff expects to see numerous efficiency applications made possible by the availability of real-time information. Using this system information to recognize and avoid issues such as power line congestion, transformer overheating, and other detrimental grid conditions, will lower the cost of transporting energy from the power plant to the customer meter and improve reliability. Optimizing the efficiency of existing assets already in rate base will help meet increasing electric demand while minimizing investment in new generation facilities and distribution assets.

The transition to a modern grid utilizing digital technology will require a large emphasis on security. The modernized grid must be capable of providing a greater level of reliability to prevent cyber-attacks and sabotage of utility equipment. Grid modernization plans should be developed concurrently with cyber security and outage mitigation strategies. Providing adequate focus on these threats prior to their occurrence will help mitigate the overall effect on Michigan customers. The longevity of a digitalized grid will rely on a utility's ability to plan for and react to both physical and cyber-attacks. Developing robust risk based management strategies can mitigate, if not eliminate, the potential of these threats coming to fruition.

The above objectives provide a glimpse of the potential benefits of moving to a modernized electric grid. Many of the benefits outlined above are being achieved in other jurisdictions throughout the country and the world. These benefits could be realized in Michigan with proper utility implementation strategies. The Staff sees prudent utility investments in AMI as a first step toward realizing a modern grid. The Staff will continuously evaluate requests from utilities for recovery of advanced digital technology for consistency with prudency principles.

Opt-Out Policies in Other Jurisdictions

A few state commissions have adopted opt-out policies for their regulated utilities. California and Maine have the two most prominent examples of commission approved opt-out policies. Costs vary across jurisdictions and service providers. Generally, an initial fee is charged to cover the fixed costs of retaining or replacing an electromechanical meter along with a monthly fee associated with the ongoing meter reading costs. For example: there is a $75 up-front charge and a $10 monthly meter reading charge associated with the opt-out tariff of Pacific Gas and Electric in California. NV Energy of Nevada charges a monthly opt-out fee, which is higher for customers in the northern part of the state and lower to south Nevada customers.

States and municipalities feature a variety of opt-out meter choices. Some states allow customers to retain their electromechanical meter, while others provide a smart meter with the radio transmitter turned off. When more than one opt-out method is offered (such as in Maine), the charge for retaining an electromechanical meter is greater than the radio disabled smart meter to reflect the actual increased cost of maintenance incurred by the utility. Also, NV Energy offers AMR meters to those who choose to opt-out. Using AMR infrastructure, while not optimal, does reduce the cost of an opt-out policy for both the customer and utility.

Not all utilities or states with AMI have an opt-out policy. The Public Service Commission of Washington D.C. denied a request for an investigation into opt-out, and earlier in 2012, an order from the Idaho Public Utilities Commission dismissed a pair of complaints from customers who demanded that an opt-out policy be created. Opt-out plans are not offered in the Canadian provinces of British Columbia and Ontario, while Hydro-Québec proposed a radio-off option with an up-front and monthly charge.

Some state regulators are in the process of discussing whether or not to offer AMI opt-out, while others are working through the process of reviewing proposals for utility opt-out policies and evaluating costs. Commissions in Texas and Arizona are currently investigating smart meter opt-out options. Lawmakers in Georgia and Pennsylvania have introduced legislation that requires opt-out. A senate bill in New Hampshire aims to make smart meter deployment strictly opt-in. Vermont’s opt-out legislation was signed into law in May, and requires opt-out and smart meter removal free of charge. Table 2 shows the status of opt-out policies across the United States and Canada as of June 2012. It is important to note that the opt-out debate is constantly changing in light of commission findings, legislative actions, and utility planning across the country. There is no universal opt-out program.

Table 2: Smart Meter Opt-Out Policies

Jurisdiction	Opt-Out Activity	Opt-Out Cost to consumers
Arizona E-00000C-11-0328	Opened a generic docket for the investigation of smart meters. (8/29/11)	
Colorado Docket 10R-799E	The commission intends to address opt-out in future proceeding. (10/17/11)	
California Decision #D1202014	California PUC approved opt-out. (2/9/12)	Analog meter: $75 initial fee, $10 monthly fee, low income customers pay reduced fees.
District of Columbia Order-16708	DC PSC denied Office of the People's Counsel's request for opt-out investigation. (4/13/12)	
Georgia Senate Bill 459	Opt-out bill passed Georgia senate. (3/13/12)	Proposes no fee.
Idaho Order-32500	Consumer request for opt-out is dismissed. (3/27/12)	
Illinois, City of Naperville	Municipal utility approved opt-out.	Radio-off smart meter: $68.35 + $24.75/mo.
Maryland Cases 9207, 9208	Interim order allows customers to defer smart meter installation pending the commission's final decision. (5/24/12)	
Maine Docket 7307	Maine PUC approved opt-out. (5/19/11)	Radio-off smart meter: $20+$10.50/mo. Electromechanical meter: $40+ $12/mo.
Nevada Docket 11-10007	NV Energy proposed opt-out tariff: AMR w/ monthly reporting. (5/1/12)	South Nevada: $98.75 + $7.61/mo. North Nevada: $107.66+$11.01/mo.
New Hampshire Senate Bill 266	Bill prohibiting electric utilities from installing smart meters without the property owner's consent. Passed by house and senate. (5/16/12)	
Oregon Advice # 11-15 Tariff Sheet # 300	Allows PGE customers to opt-out of a digital meter. Idaho Power has digital meters in Oregon with no opt-out option. (8/10/11)	Portland GE: $254 + $51/mo.
Pennsylvania House Bill 2188	A bill allowing opt-out is in committee. (2/8/12)	
Quebec	Régie de l'énergie considering Hydro-Québec's proposed opt-out rates. (3/14/12)	Hydro-Quebec: $98 + $17/mo.
Texas Filing 40190	Petition requesting an opt-out being considered by the PUC. (2/16/12)	
Vermont Act 170	Law does not allow opt-out fees or smart meter removal fees. (5/18/12)	No cost for opt-out.

Opt-out Options

The Staff concludes that providing an opt-out option is the best solution for customers who have concerns about smart meters. The Staff recommends that utilities investigate a variety of opt-out options. Electromechanical meters may be a viable opt-out option for some customers; however, maintaining electromechanical test facilities, inventory, and manual meter reading could result in higher incremental costs.[54] The traditional electromechanical meter is obsolete and currently not in production. Offering customers an electromechanical meter as an alternative to a smart meter is not a long-term solution.

Other options are the installation of a smart meter that does not have a communicating radio, relocating a smart meter on the customer's premise, or hard-wiring a smart meter into the network. A smart meter without a communicating radio allows the utility to maintain one type of meter. However, manual meter reading would still be required. Customers with a non-communicating meter will not receive some benefits of AMI, and would not, for example, be able to fully participate in new rate structures.

Smart meter relocation would allow customers to still receive all the benefits of AMI. Meter relocation may result in a higher initial cost and may not be feasible at some locations. Currently, administrative rules governing meter relocation allow the customer to request meter relocation at the customer's expense.[55]

A wired smart meter also permits opt-out customers to receive all AMI benefits by allowing two-way communication with the utility without using radio frequency (i.e. power line carrier, fiber optic cable, etc.). This option may be costly and may not be feasible within the confines of the utility infrastructure or of the customer's premises.

As discussed above, there are costs associated with allowing a customer to opt-out. Most states have acknowledged these costs by assessing charges that reflect the actual cost of maintaining a non-AMI meter.

No opt-out tariffs have been submitted to the Commission by any Michigan utilities as of June 2012. The Staff believes that ratemaking for the opt-out provision should be based on cost-of-service principles. If AMI meters result in a reduced cost of service, this could be accounted for by either an additional charge for those customers choosing to opt-out or a discount for those customers with an AMI meter.

[54] Commission billing rules allow for customers to read their own meters. However, the utility must verify the meter reading once a year. (Consumer Standards and Billing Practices for Electric and Gas Residential Services, R 460.115)
[55] Consumer Standards and Billing Practices For Electric and Gas Residential Services, 1999 AC, R 460.116

RECOMMENDATIONS AND CONCLUSIONS

Health and Safety

- After careful review of the available literature and studies, the Staff has determined that the health risk from the installation and operation of metering systems using radio transmitters is insignificant.

- The appropriate federal health and safety regulations provide assurance that smart meters represent a safe technology.

Data Privacy

- The Staff recommends that all stakeholders identify and implement privacy policy considerations through administrative rules, tariffs, orders and/or other means.

- Customer data privacy policies should include provisions addressing customer consent, individual access, customer choice, notice and purpose, collection and scope, data retention and management and accountability.

Cyber Security

- Each utility should adopt an annual independent security audit of the mechanisms of customer access, third party access and internal cyber risk-management practices.

- As outlined in the NARUC resolution regarding cyber security, the Staff intends to maintain a dialogue with regulated utilities to ensure that they are in compliance with standards, and that preparedness measures are employed to deter, detect and respond to cyber-attacks and to mitigate and recover from them.[56]

- Utilities should adopt the same breach notification policies as other states have adopted, namely the notification of any breach affecting 1000 or more customers within two weeks of the breach.

- Each utility should be required to file a yearly breach notification summary with the Staff, detailing all breaches of customer information, including any third party breach information.

Customer Education

- The Staff recommends utilities develop and implement a new education strategy similar to those used in other jurisdictions. Education program results should reflect high levels of customer engagement, acceptance and enthusiasm with their smart meter program.

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[56] NARUC, *Resolution Regarding Cybersecurity*, *et al.*

- The strategy should include metrics to measure the overall effectiveness of the education program.

National Policy

- The United States Congress has passed several laws that support the upgrade of the electric grid, including deployment of smart meters for residential and other types of customers. These laws have provided a framework for smart grid, including smart meter deployment in the United States.

- Numerous prestigious agencies and institutions have considered the national outlook for the smart grid and indicate that installing smart grid technologies, including smart meters, will have a positive benefit on the United States' electric grid. These reports urge the United States to follow the directives of the federal law and update the electric grid.

Policies and Practices

- Several areas of current rules and tariffs will be affected by AMI deployment in Michigan. Administrative rules, tariffs, and Commission orders should be considered, and the most effective methodology should be employed to ensure customers have adequate protections.

- It is recommended that all stakeholders work to analyze and identify the most appropriate implementation methods for addressing the policy considerations. Stakeholders should routinely review all policies related to smart grid as smart grid technologies continue to develop.

Smart Grid Vision

- A Michigan smart grid vision should provide direction to implement technology that will enhance the functionality of the electric grid. All components of electric grid improvements, including AMI installation, distribution infrastructure replacement, and electric generation should reflect the larger objectives of a smart grid vision.

- The Staff proposes that future smart grid investments from utilities must correlate with the following objectives aimed at delivering transparent and identifiable benefits to ratepayers: accommodate advanced generation and storage options; enable informed participation by all customers; support new products, services, and markets; optimize existing assets, increase efficiency and improve reliability; and operate resiliently against physical and cyber-attacks.

Opt-Out

- The Staff concludes that an opt-out option or options is the best solution for customers who have concerns about smart meters.
- The Staff believes that ratemaking for the opt-out provision should be based on cost of service principles. If AMI meters result in a reduced cost of service, this could be accounted for by either an additional charge for those customers choosing to opt-out or a discount for those customers with an AMI meter.

Appendix A

Additional Resources:

- *National Institute of Standards and Technology Interagency Report 7628, Guidelines for Smart Grid Cyber Security: Vol. 1, Privacy and the Smart Grid*, August 2010. http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf

- *National Institute of Standards and Technology Interagency Report 7628, Guidelines for Smart Grid Cyber Security: Vol. 2, Privacy and the Smart Grid*, August 2010.
- http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf

- North American Energy Standards Board, *Third Party Access to Smart Meter-based Information*, April 20, 2012.

- Oklahoma Electric Usage Data Protection Act, H.B. 1079, May 20, 2011.

- C. Hagan & K. Thomas, *A Model Privacy Policy for Smart Grid Data Institute for Energy and the Environment*, Vermont Law School, November 4, 2011.

- Public Utility Commission of Texas, Electric Substantive Rules, Chapter 25 Rules. http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/Electric.aspx

- Federal Trade Commission, Fair Information Practice Principles. http://www.ftc.gov/reports/privacy3/fairinfo.shtm

- Colorado Department of Regulatory Agencies Public Utilities Commission, 4 Code of Colorado Regulations 723-3 Part 3, Rules Regulating Electric Utilities, February 14, 2012.

- United States Code 47 §222, Privacy of Customer Information, January 7, 2011.

- Naperville Smart Grid Initiative, Naperville Smart Grid Customer Bill of Rights, Ordinance No. 11-029, February 16, 2011.

- Washington Administrative Code, Chapter 480-100, Electric Companies, February 15, 2012. http://apps.leg.wa.gov/wac/default.aspx?cite=480-100

- California Public Utility Commission, Public Utility Code Chapter 4-5. http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=puc

- NAESB Data Privacy Task Force, Team Five-State and Province Law. www.naesb.org/pdf4/data_privacy_042111w3.doc

- Arizona State Legislature, Consumer Protections; rules; confidentiality; unlawful practice http://www.azleg.gov/FormatDocument.asp?inDoc=/ars/30/00806.htm&Title=30&DocType=ARS

- California Public Utilities Commission, Decision Adopting Rules To Protect The Privacy And Security Of The Electricity Usage Data Of The Customers Of Pacific Gas And Electric Company, Southern California Edison Company, And San Diego Gas & Electric Company
- http://www.azleg.gov/FormatDocument.asp?inDoc=/ars/30/00806.htm&Title=30&DocType=ARS

- Colorado Department Of Regulatory Agencies, Public Utilities Commission, 4 Code of Colorado Regulations (CCR) 723-3, Part 3, Rules Regulating Electric Utilities.
  http://www.dora.state.co.us/puc/rules/723-3.pdf

- New York Department of Public Services, Smart Grid Privacy Statement.
  http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=10-E-0285

- Oklahoma State Legislature, Electric Usage Data Protection Act.
  http://www.oklegislature.gov/BillInfo.aspx?Bill=HB1079&Tab=0

- United States Department of Energy, Smart Grid Privacy Workshop Summary Report.
  http://www.smartgrid.gov/sites/default/files/doc/files/Privacy%20report%202012_03_19%20Final.pdf

- United States Department of Homeland Security, Privacy Policy Guidance Memorandum, December 29, 2008.
  http://www.dhs.gov/xlibrary/assets/privacy/privacy_policyguide_2008-01.pdf

- United States Department of Energy, Electricity Subsector cyber security risk management process, March 2012: Public Comment Draft.
  http://energy.gov/sites/prod/files/RMP%20Guideline%20Second%20Draft%20for%20Public%20Comment%20-%20March%202012.pdf

- Executive Office of the President, A Policy Framework For the 21st Century Grid, June 2011.
  http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf

- National Institute of Science and Technology, NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0.
  http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf

- ASIS International, Utility and Smart Grid Security: The impact of NERC CIP Standards and NISTIR 7628 to the Utility Industry.
  http://www.asisonline.org/councils/documents/UtilitySmartGridSecurity.pdf

eia U.S. Energy Information Administration

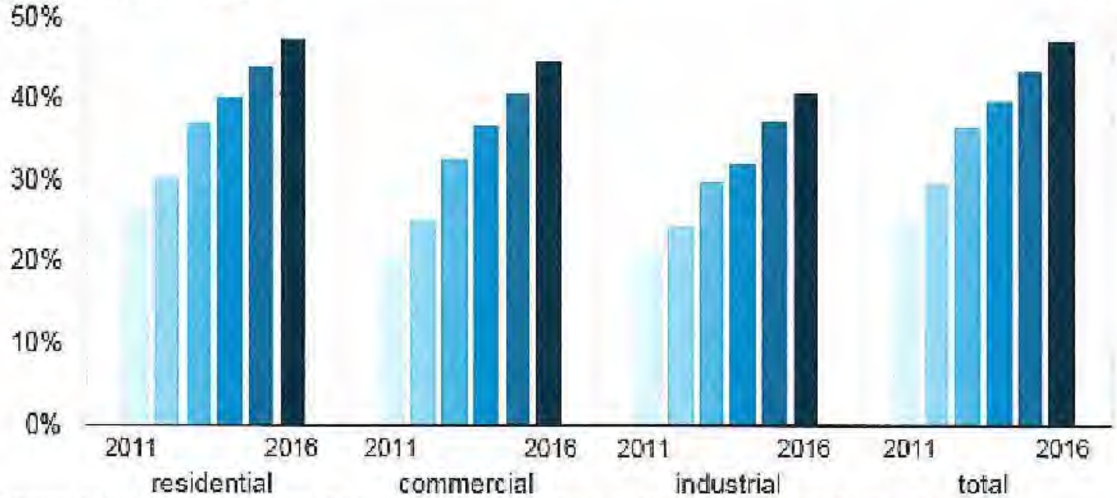
Case No. U-20276
Exhibit A-44 (AMI-2)
Witness: Brynick
Page 1 of 2

Today in Energy

December 6, 2017

Nearly half of all U.S. electricity customers have smart meters

Smart electricity meter installations (2011-2016)
percent of sector total

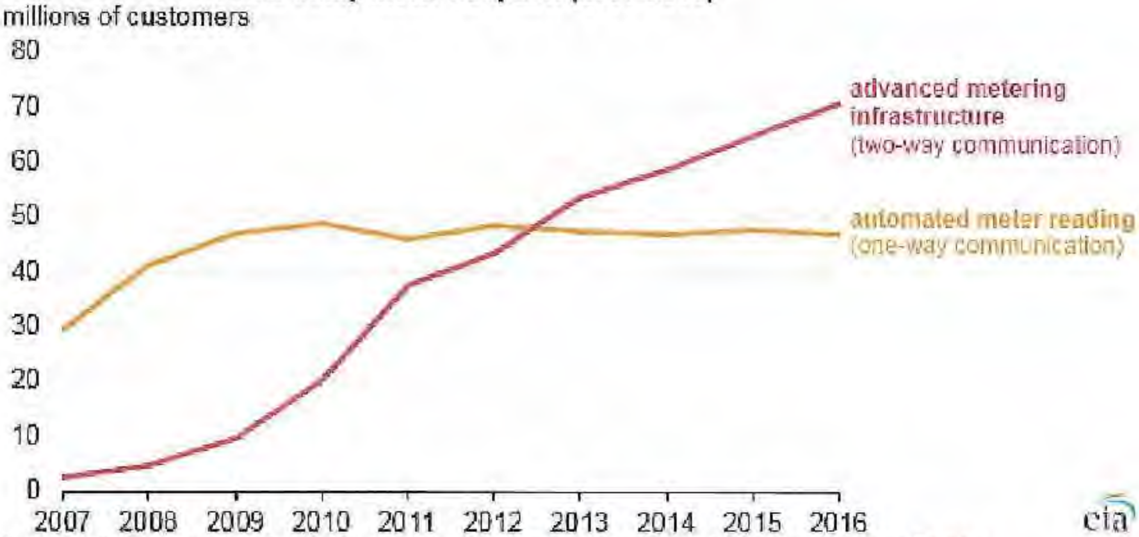


Source: U.S. Energy Information Administration, *Annual Electric Power Industry Report*

Installations of smart meters have more than doubled since 2010—almost half of all U.S. electricity customer accounts now have smart meters. By the end of 2016, U.S. electric utilities had installed about 71 million advanced metering infrastructure (AMI) smart meters, covering 47% of the 150 million electricity customers in the United States.

Smart meters have two-way communication capability between electric utilities and customers. One-way meter-to-utility communication, also known as automated meter reading (AMR), was more prevalent before 2013. Since then, two-way AMI smart meter installations have been more common based on data collected in EIA's annual electric utility surveys.

U.S. advanced electric utility meter adoption (2007-2016)
millions of customers



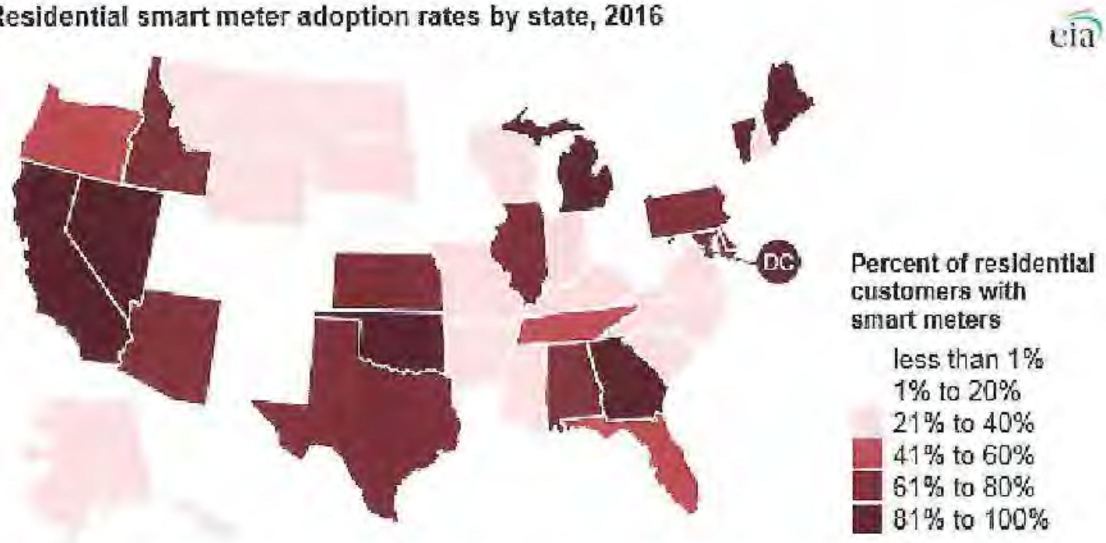
Source: U.S. Energy Information Administration, *Annual Electric Power Industry Report*

Two-way AMI meters allow utilities and customers to interact to support smart consumption applications using real-time or near real-time electricity data. Smart meters can support demand response and distributed generation, improve reliability, and provide information that consumers can use to save money by managing their use of electricity.

AMI data provide utilities with detailed outage information in the event of a storm or other system disruption, helping utilities restore service to customers more quickly and reducing the overall length of electric system outages.

Case No. U-20276
Exhibit A-44 (AMI-2)
Witness: Brynick
Page 2 of 2

Residential smart meter adoption rates by state, 2016



Source: U.S. Energy Information Administration, *Annual Electric Power Industry Report*

Residential smart meter penetration rates vary widely by state. Washington, DC, has the highest AMI penetration rate at 97%, followed by Nevada at 96%. Six other states had a residential AMI penetration rate higher than 80% in 2016: Maine, Georgia, Michigan, Oklahoma, California, and Vermont. In 2016, Texas added the most residential AMI meters of any state, installing smart meters on more than 200,000 customer accounts.

Differences in smart meter penetration rates are often driven by state legislation and regulation, as some states require that regulators approve utilities' cost recovery mechanisms for metering projects. The Smart Electric Power Alliance publishes reports on state-level actions on advanced metering, among other topics.

Many residential customers may not be aware that they have a smart meter. EIA last conducted the Residential Energy Consumption Survey (RECS) in 2015, a year when residential smart meter adoption was about 44% nationwide. In that year, 22% of households reported having a smart meter, 49% reported not having one, and 29% responded that they did not know. Only 8% of households reported being aware that they had access to hourly or daily data, and just 4% said they had accessed or viewed that data.

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Itron

OpenWay® Riva Security

CONTENTS

WHITE PAPER

The cities of the future may be smart – but will they be cyber safe?

All together, the smart-city market is expected to exceed $1.7 trillion in the next 20 years. But the interconnectivity across the virtual and physical infrastructure that makes a smart city work also creates new and substantial cybersecurity risks. With each additional access point, sensitive data exposure vulnerabilities expand. Smart cities can be susceptible to numerous cyber attack techniques, such as remote execution and signal jamming, as well as traditional means, including malware, data manipulation and DDOS. To counter the risks, comprehensive smart-city plans designed to safeguard what is clearly "critical infrastructure" are needed on behalf of all parties involved, from the individual citizen to large public and private institutions.

- PwC, 'Smart cities: five smart steps to cybersecurity', March 3, 2017

THE CHANGING LANDSCAPE

Utility companies are being transformed, driven by advances in technology, business conditions and the need to manage resources more effectively. They are under increasing pressure to provide new services, develop new revenue streams and provide enhanced levels of customer service and interaction.

In addition, as migration toward urban centers increases, cities are being transformed into 'smart cities.' Smart cities are under pressure to increase economic growth, engage more effectively with their citizens and utilize new technologies to make the urban landscape more livable, sustainable and economically vibrant.

Some examples of the new technologies and services that utilities and smart cities will need to incorporate include:

- Network edge analytics
- Electric vehicle charging
- Distributed energy resource integration
- Energy and water efficiency programs
- Solar
- Prepayment
- Smart streetlights
- Environmental/gas/methane monitoring
- Traffic control

These new technologies and services present new opportunities for utilities and smart cities, but at the same time, they increase security challenges.

SECURING SMART UTILITIES AND SMART CITIES

As new ways to deliver, monitor and manage water, gas and electricity emerge and new capabilities, technologies and services are developed and introduced, new opportunities for security threats also arise. Those threats, combined with the challenges of maintaining grid security, securing the network against cyberattacks and malware, or maintaining compliance with government regulations and mandates can quickly overwhelm cities and utilities. They need a field area networking solution that will provide room for future expansion with new technologies and services, while at the same time providing the security necessary to counter evolving threats.

Itron's OpenWay® Riva solution, built for the Internet of Things (IoT) world, provides the answer.

OpenWay Riva is the solution built for the Internet of Things (IoT) world

For years, energy and utility organizations have been high-profile targets for hackers, cyberterrorists and foreign governments.

Infrastructure organizations are seen as vulnerable targets that can be used to cause mass disruption with a relatively few keystrokes pressed from a home located a few blocks away or from a foreign nation on the other side of the world. Because attacks on the energy and utility sector are often kept confidential—unlike data breaches suffered by retailers and healthcare organizations that are highly publicized to warn customers and patients whose information has been stolen—the public has little knowledge of infrastructure attacks, and even some cybersecurity professionals are unaware of a breach's true extent. New information, however, reveals that cyberattacks on utility and energy organizations are a serious and growing threat.

- Rishi Bhargava, 'The Energy and Utilities Sector Remains Vulnerable to Hackers', Electric Light & Power online, June 27, 2017

COMPREHENSIVE, END-TO-END SECURITY

Itron views security as the most critical and foundational concern in defining requirements of our smart grid-enabling architectures. Leveraging our breadth of experience in AMI deployments and projects across the globe, Itron and our strategic partner Cisco designed OpenWay Riva with an end-to-end integrated security solution using a defense-in-depth approach, where multiple layers of protection are strategically located throughout the multi-service architecture to provide the industry's most comprehensive, unified security available today.

This architecture delivers a true multi-purpose, secure communications platform for utilities and cities and protects the integrity of data, communications, and controls in an open, multi-service, multi-protocol network environment.

An iterative design process ensures that all possible threats have been addressed and mitigating measures are built into the OpenWay Riva solution. The benefit of this approach is the increased security of the system.

The OpenWay Riva solution was designed to support gas, water, electricity and smart cities by providing increased functionality, visibility and management, along with increased security. OpenWay Riva provides layered security controls and management to protect the multi-service IPv6 field area network (FAN) and all the devices and applications that run on it.

SECURITY AT THE NETWORK LAYER

The multi-service IPv6 network provides consistent security controls for all utility applications using the FAN. The FAN architecture provides unprecedented:

Access Control:

Strong authentication of nodes is achieved by taking full advantage of a set of open standards including IEEE 802.1x, Extensible Authentication Protocol (EAP) and Remote Authentication Dial-In User Service (RADIUS). This "white-listing" approach requires that every device joining the IPv6 network be authenticated before being allowed access to the network and smart metering system. Field area routers, along with intermediate meters, pass on a new device's credentials to the centralized Authentication, Authorization and Accounting (AAA) server. Once authenticated, the new device is then allowed to join the network, provided with an IPv6 address and mesh key, and will be authorized to communicate with other nodes.

Data Integrity, Confidentiality, Privacy:

The FAN employs network-layer encryption (IPsec with AES encryption) in the Wide Area Network (WAN) and link-layer encryption (AES on IEEE 802.15.4g or IEEE 1901.2) in the Neighborhood Area Network (NAN). This design choice preserves network visibility into the traffic at the router and enables use of IP-based techniques of multicast, network segmentation, and quality of service (QoS). It also allows smart meters and other endpoints to be low-cost constrained nodes that only do link-layer encryption while the field area router does both network-layer and link-layer encryption. Additional protection at the application-layer is provided by Itron's enhanced security architecture which provides confidentiality, message integrity and proof of origin (digitally signed firmware images or digitally signed commands as part of application protocols such as DLMS/COSEM) between the headend and the meter register itself.

Threat Detection and Mitigation:

The security architecture supports tools such as DDI and IPAM, VLANs, secure tunnels, Virtual Routing & Forwarding (VRFs), or Generic Routing Encapsulation (GRE) to achieve network segmentation of functional elements that should never communicate with each other. Additionally, access lists and firewall features can be configured on FAN and substation routers respectively, to filter and control access in the distribution and substation part of the grid.

Device and Platform Integrity:

Field area routers and meters are built with tamper resistant mechanical designs that generate alerts when physical tampering is detected. Additionally, each router motherboard is equipped with a dedicated security chip that provides secure unique device identifier (802.1AR), immutable identity, and certifiable cryptography, entropy source with true randomization, memory protection and image signing / validation.

Secure Field Tools:

Secure access is required of devices in the field using digitally signed time-based credentials and mutual authentication. In addition, the rule of least privilege can be applied to field access, preventing any contractor/field tech from being able to see device passwords or performing higher-privileged commands on devices.

SECURITY AT THE APPLICATION LAYER

At the application level, the OpenWay Riva solution provides an enhanced security architecture that emphasizes integrity of control, availability and confidentiality for the AMI application.

Commands and payloads are encrypted and digitally signed by OpenWay, supported by the Itron Security Manager (ISM), before they are transferred over the network. In this manner, the messages between the applications and endpoints are protected, regardless of the underlying network infrastructure. OpenWay Riva also provides auditing of both the security activities and the events being returned by the meter or device, managing the encryption keys and the larger set of security components deployed with the system. The OpenWay Riva solution protects information and commands from the headend system to the endpoint; therefore, the meter or device only operates on authenticated control commands.

OpenWay Riva application-layer security uses the following security appliances and applications:

Itron Security Manager (ISM):

Manages encryption, authentication, decryption and validation of data and commands to and from enabled endpoints. ISM also manages the key exchanges and security state for endpoints and repeaters in a cellular network.

Hardware Security Module (HSM):

Generates and secures asymmetric signing (command and revocation) keys (ECC, 256-bit). The HSM is connected over secure API to the ISM and is considered an integrated part of the ISM. No other devices or systems connect to the HSM.

SECURITY VALIDATION & VULNERABILITY TESTING

Security validation and vulnerability testing is conducted on the end-to-end system as part of Itron's overall ISO-compliant software development lifecycle process. This type of testing comprises security validation and vulnerability assessments, as well as penetration testing. Our assessment process not only accounts for the technical aspects of the solution, but strives to introduce technical controls that mitigate human vulnerabilities as well.

A dedicated team of internal security experts, as well as external, third-party organizations perform the testing. This testing is external to the product development and quality assurance organizations to help ensure the rigor of test cases and the independence of their findings.

Itron's solution security has also been tested independently by third parties at San Diego Gas & Electric, Southern California Edison, DTE Energy, National Grid, and BC Hydro. These assessments included penetration testing of the headend, field area routers, and meters as well as bench tests of physical attacks, port scanning, and system wide penetration attempts.

A COMPLETE SOLUTION

OpenWay Riva, the next generation IoT solution for utilities and smart cities, is a significant leap forward in technology. Built upon Itron's existing OpenWay IPv6 network, Itron has added a powerful distributed computing platform that uses distributed intelligence and adaptive communications technology to help solve business challenges and accelerate innovation. OpenWay Riva is the only solution that delivers both security and flexibility, allowing utilities and smart cities to expand the services offered to consumers while providing the security required to protect both data and the network.

Itron and our technology partners are working with global utilities and municipalities to develop and validate use cases that leverage these new capabilities to make real-time operational decisions at the edge of the network. This enables what we call the "active grid" or "active network," which is an active network that drives measurable valuable business outcomes.

Smart Cities Are Going to Be a Security Nightmare

The inevitability of cyberattacks is a lesson the private sector has learned the hard way. As cities adopt smart initiatives, they'd be wise to make data security a priority from the outset.

- Todd Thibodeaux, 'Smart Cities Are Going to Be a Security Nightmare', Harvard Business Review, April 28, 2017

What Threats Do Smart Cities Face?

Since cities account for the consumption of around 70% of the energy produced globally and the generation of 70% of the world's gross domestic product (GDP), any kind of intrusion, sabotage, and intelligence collection with malicious intent will have a great impact on smart cities.

- TrendMicro, 'Securing Smart Cities', May 30, 2017

SECURITY TODAY… AND TOMORROW

OpenWay Riva enables a wide variety of devices and assets to communicate and collaborate directly with each other. This means massive amounts of sensitive data will now traverse the network as these assets transmit, receive and share data, collaborate, analyze, decide and act in real time.

To put this in perspective, in 2016, the annual amount of global IP traffic (i.e., data across the Internet) was 1.2 ZB (zettabyte, or 10^{21} bytes) or 96 EB (exabyte, or 10^{18} bytes) per year. This is expected to grow to 3.3 ZB per year by 2021, or 278 EB per month. From 2016 to 2021 the Compound Annual Growth Rate (CAGR) for IP traffic will grow 24 percent.[1]

Obviously, security in this environment becomes even more critical.

The active grid requires state-of-the-art security capable of countering current and future threats, while being able to evolve and scale to support new use cases as they are developed. OpenWay Riva technology provides utilities and smart cities with that security.

A few of the security-related outcomes the OpenWay Riva solution delivers include:

FOR SMART CITIES

Connected Infrastructure

Foundational to becoming a smart city are smart utility services, where energy and water use is being monitored and proactively managed for safety, waste reduction, conservation and sustainability goals. Through distributed applications and cloud services, Itron can help smart cities solve problems such as resource waste reduction, electrical distribution, streetlight management, water conservation and management of renewable power.

Itron helps smart cities accomplish these goals through an ecosystem of partners that utilize the interoperable OpenWay Riva environment to develop apps to run on the platform, or to embed Itron Riva technology into their devices. Commercially available chip set manufacturers are also putting the Itron Riva technology on their standard products, so hundreds of device manufacturers will have immediate access to join the network. Device and sensor manufacturers can also easily work together to bring new applications faster to market. Itron Riva technology ecosystem partners undergo a certification process

that includes the same security rigor and controls as Itron devices and applications, ensuring consistent security measures throughout the entire network. This partner ecosystem means utilities and smart cities are not reliant on one vendor for product innovations, providing them with access to new applications much faster than in the past.

However, to take advantage of these programs and realize the benefits, cities must be connected. Being connected allows smart cities to leverage data and technology in real time to drive real operational efficiencies and outcomes that matter to citizens and businesses.

Itron is a world leader in connecting infrastructure and managing data with over 150 million connected devices in cities throughout the world. Itron's next-generation solution for smart cities, OpenWay Riva, is built upon its proven OpenWay IPv6 network. The OpenWay Riva solution connects IoT devices through a powerful, fully standards-compliant distributed computing platform enabling endless possibilities for emerging city applications.

FOR ELECTRICITY

Diversion Detection:

With the OpenWay Riva platform, diversion detection can now be based on real-time, continuous, and localized analysis of changes in electricity current flows and voltage levels in the distribution network to distinguish legitimate metered loads versus those from theft. Through the meter's ability to communicate directly with other meters at different levels of the network, and knowing exactly where they are located on the distribution system, the system identifies when current is drawn on the secondary of a transformer that did not go through a meter, greatly increasing the accuracy and timeliness of diversion detection.

The Importance of Grid-wide Security Is Difficult to Overstate

To thwart attacks, utilities must deploy comprehensive security that spans field devices, the communications network and the cloud. In other words, utilities need an end-to-end approach that integrates both IT and operations technology (OT).

- Hugo Moreno, 'Staying On The Grid: Utilities Grapple With Security And The Internet Of Things', Forbes Insights, Nov. 15, 2016

Detection of Unsafe Grid Conditions:

High-impedance connections (HIC) or "hot spots" on the low-voltage distribution system represent a serious and ongoing safety risk, as well as causing customer voltage problems and utility energy losses. By continuously calculating and monitoring impedance throughout the lower voltage system, distributed intelligence changes the game for HIC detection. OpenWay Riva provides a practical and cost-effective solution for utilities to identify these losses, voltage anomalies and potential safety issues before they become a safety hazard or a costly liability.

FOR GAS

Safety:

The OpenWay Riva solution combines peer-to-peer communications and analysis of data throughout the gas distribution network to aid in pipeline safety. Utilities can pair methane sensors, seismic sensors, flood sensors and more with remote disconnect valves – enabling the utility to potentially alleviate dangerous situations and improve the safety of communities, employees and first responders.

System Integrity:

With OpenWay Riva, new applications are emerging to monitor pressure, temperature, pipeline stress via strain gauges and cathodic protection to aid in pipeline integrity management, to perform pressure studies, and to hit check-in dates for cathodic protection reports.

Methane Sensing:

OpenWay Riva's methane sensing application helps keep utility personnel and customers safe by monitoring for unsafe or changing levels of methane. Further, remote disconnect valves can be paired with the methane sensor to shut off gas service when elevated levels of methane are detected. By deploying methane sensors in highly-populated areas of a utility service territory, such as hospitals, schools, amusement parks, shopping centers and sports venues, methane gas leaks can be identified more quickly and gas service automatically shut-off immediately, alleviating potentially dangerous situations before they arise.

FOR WATER

Water Leak Detection:

The OpenWay Riva platform's leak detection solution includes an acoustic leak sensor and analysis and presentment software designed to be permanently installed, enabling the utility to continuously monitor its entire distribution network. The leak sensor is powered by the OpenWay Riva water module and supplies acoustic samples to the module for storage and transmission through the network to leak detection software. The leak detection software enables the utility to identify and prioritize potential distribution leaks for maintenance, reducing water loss and enabling the utility to address leaks prior to them becoming costly main breaks.

Remote Disconnect:

Itron has certified two third-party remote disconnect valves to operate within the OpenWay Riva solution. This advanced functionality enables utilities to remotely disconnect or limit water flow to an end customer. It reduces the need to roll a truck to perform this function, saving the utility a significant amount of money while enhancing the safety of field crews.

Advanced Sensing:

The OpenWay Riva platform enables the deployment of additional sensors on the water distribution system to monitor pressure and water quality. These sensors enable utilities to continuously monitor the distribution system pressure and water quality, while also correlating with other data, to enhance analysis and reporting.

EQUIPPED FOR THE FUTURE

Itron's OpenWay Riva is the only solution for utilities and smart cities that delivers scalable security while enabling support for new services, capabilities and business outcomes. The OpenWay Riva solution also provides true interoperability for an open ecosystem of grid devices and network sensors – delivering the active grid that utilities and smart cities demand.

Deploying a unified solution on one multi-purpose network provides well-defined points of interoperability between systems and greatly simplifies and reduces integration costs and difficulties. The OpenWay Riva solution allows utilities and smart cities to focus on creating business value through outcomes that improve services and enhance the lives of customers and citizens, without having to worry about security risks.

THE SOLUTION IS CLEAR

Utilities and smart cities need to deploy a solution that will not only provide robust security today, but will also provide the ability to secure and support new technologies and capabilities in the future.

Itron's OpenWay Riva is that solution.

To find out how OpenWay Riva solutions can help your utility or smart city, visit the OpenWay Riva website or contact your sales person.

[1] Cisco Systems, 'The Zettabyte Era: Trends and Analysis', updated June 7, 2017

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Line	**<u>Opt Out Meter Reading Cost Estimate</u>**		
1			
2	**Assumptions**		
3	No. of Opt-Out Customers	500	
4	2019 Full Rate Meter Technician Wage ($39.73)	$54.83	38% Loader
5	Meter Ops Mgr Hourly Wage ($47.77)	$65.92	38% Loader
6	Contact Center Lead Wage ($23.18)	$31.99	38% Loader
7	2018 V-01 Vehicle Rate ($7,121.95/year)	$3.42	Hourly $
8	Annual MVRS Maintenance/Licensing ($4,742.40)	$395.20	Monthly $
9	Opt-Outs are on a single MRU per district (6 MRU's)		

Line	*Percentage of meters by district*		*# of Opt Out*	*Estimated time (Hrs) to read MRU*
10				
11	Houghton	41.11%	206	10
12	Iron River	7.26%	36	2
13	Ontonagon	5.19%	26	3
14	Ishpeming	24.24%	121	7
15	Munising	9.49%	47	8
16	Delta	12.71%	64	4
17		**100.00%**	**500**	**34**

Line			
18			
19	Monthly Field Labor Cost	$6,382.81	
20	Annual Field Labor Cost	$76,593.76	
21			
22	Monthly Administrative Cost	$285.66	1 Hour/week MVRS Admin
23	Annual Administrative Cost	$3,427.98	
24			
25	Monthly Contact Center Cost	$63.98	2 Hrs/Month
26	Annual Contact Center Cost	$767.72	
27			
28		Total	Per Customer
29	**Total Monthly Meter Reading Cost**	**$7,127.65**	**$14.26**
30	**Total Annual Meter Reading Cost**	**$85,531.86**	
31			
32			

Line			
33	**<u>Estimate of Cost to Exchange and Test Meter for Opt Out Post Go-Live</u>**		
34			
35	**Assumptions**		
36	2019 Full Rate Self-Contained Meter Electrician Wage ($39.73)	$54.83	38% Loader
37	Contact Center Lead Wage ($23.18)	$31.99	38% Loader
38	2018 V-01 Vehicle Rate ($7,121.95/year)	$3.42	Hourly $
39	30 min for drive time and meter XEM	30	
40	10 minutes per test and associated processes	10	
41		40	Minutes Per XEM
42			

Line					
43	*Estimated Cost per Meter*	(V01-$1.71)	Testing		
44	Field Labor	$29.12	$9.14	$38.26	
45	Customer Contact Center			$23.99	45 minutes Per
46					
47			**Total Cost**	**$62.25**	

Michigan Public Service Commission
Upper Peninsula Power Company
AMI Business Process Requirements

Case No.: U-20276
Exhibit No.: A-47 (AMI-5)
Schedule:

Witness: Brynick

Business Process Requirements

Business Process	Description	Functional Considerations
Devise Management	Create and Maintain Service Location Data, Capture usage Data, Manage and Process Data Usage Exceptions, Meter Install/Remove/Replace Process Changes	Meter Configuration and Master Data, naming conventions, data channels, EDM Profiles, one meter per meter socket, provide report to reconcile meter, support syncronization of VEE
Billing	Manage Meter Reading and Billing Schedule, Compute Bills for Utility Service, Manage and Process Billing Exceptions, Produce and Distribute Invoices	Enable monthly billing, support all active rates as well as rate changes due to regulatory
Customer Service	Process Customer Moves and Transfers, Order creation and closure, Initiate the meter reading process, Process Meter Disconnections and Reconnections, On Demand Reads, Alerts, Device Status, Interaction Record created based off AMI Activity	Dunning and Collections, remote Disconnection/Reconnection, disconnection due to no payment or move out and reconnection to receiving payment,
Mass Deployment	Manage and Process Mass Deployments, Process Opt-out and Deferral Requests	Selection of meters/locations by MRU, collection of info related to service, allow customers to request deferral/opt-out of AMI meter, support processing of deployment outputs as well as processing of service orders
Mobius (Customer Portal)	Enhance Info/Data for customers in Customer Portal	Daily Usage (consumption with charts/graphs), be able to compare day to day, week to week, month to month, show read as usage calculated

Michigan Public Service Commission
Upper Peninsula Power Company
AMI Project - ITRON Openway Riva RF Mesh Cost Analysis (per year)
AMI Cost Analysis

Case No.: U-20276
Exhibit No.: A-48 (AMI-6)
Schedule:

Witness: Brynick

AMI Project - ITRON Openway Riva RF Mesh Cost Analysis (per year)

	A	B	C	D	E	F	G	H	I	J	K
Line		On-Premise						Hosted			
1	**Costs**	**OWOC**		**MDM - 3 Tier**		**2 Tier**		**OWOC**		**MDM - 3 Tier**	
2		**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**
3	**Project Preparation (Professional Services)**										
4	UPPCO - Implementation/Detail Design Workshops	$ 600,000		$ 600,000		$ 600,000		$ 600,000		$ 600,000	
5	UPPCO - Communcations	$ 25,000		$ 25,000		$ 25,000		$ 25,000		$ 25,000	
6	UPPCO - WO# 4000040869 To Date Costs	$ 91,767		$ 91,767		$ 91,767		$ 91,767		$ 91,767	
7	Itron - Implementation (Cap)/On-going (O&M)	$ 796,600		$ 1,248,000		$ 635,200		$ 412,800		$ 908,400	
8	Itron - Project Expenses	$ 171,710		$ 129,750		$ 108,155		$ 53,520		$ 118,190	
9	Itron - CGR Integration Services (Utility Customization)	$ 51,100		$ 51,100		$ 51,100		$ 51,100		$ 51,100	
10	Utegration - SAP/MDM Interface	$ 500,000	$ 150,000	$ 2,204,439		$ 1,867,135	$ 61,015	$ 500,000	$ 150,000	$ 2,204,439	
11	Utegration - Project Expenses	$ 150,000		$ 150,000		$ 150,000		$ 150,000		$ 150,000	
12	**Subtotal**	**$ 2,386,177**	**$ 150,000**	**$ 4,500,056**	**$ -**	**$ 3,528,357**	**$ 61,015**	**$ 1,884,187**	**$ 150,000**	**$ 4,148,896**	**$ -**
13	**UPPCO Backend - IT Systems**										
14	UPPCO - IT Hardware	$ 2,900,000	$ 360,000	$ 3,213,399	$ 429,439	$ 3,197,414	$ 429,439	$ 40,035	$ 302,027	$ 40,035	$ 302,027
15	UPPCO - IT Labor		$ 288,000		$ 288,000		$ 288,000	$ 100,000	$ 144,000	$ 100,000	$ 144,000
16	**Itron Headend (Software)**										
17	OpenWay Operations Center (OWOC) - Collection Manager	$ 53,439		$ 53,439		$ 53,439					
18	Collections Manager Annual Maint/Support Fees		$ 10,688		$ 10,688		$ 10,688				
19	Field Network Manager (FND-IoT)	$ 282,061		$ 274,411		$ 282,061					
20	Field Network Manager (FND-IoT) Annual Maint/Support		$ 83,429		$ 83,429		$ 83,429				
21	ITRON IEE Meter Data Manager (MDM)/ISAIM Adapter			$ 143,657		$ 143,657					
22	MDM/ISAIM Adapter - Annual Maint/Support				$ 22,266		$ 22,266				
23	OpenWay Operations Center (OWOC) - Security Manager	$ 10,688		$ 10,688		$ 10,688					
24	Security Manager Annual Maint/Support		$ 2,138		$ 2,138		$ 2,138				
25	ITRON Performance Manager	$ 44,355		$ 44,355		$ 44,355		$ 19,030		$ 19,030	
26	Performance Manager Annual Maint/Support		$ 8,871		$ 8,871		$ 8,871		$ 26,324		$ 26,324
27	IoT Device Manager Application	$ 13,000		$ 13,000		$ 13,000		$ 13,000		$ 13,000	
28	**Subtotal**	**$ 403,543**	**$ 105,126**	**$ 539,550**	**$ 127,392**	**$ 547,200**	**$ 127,392**	**$ 32,030**	**$ 26,324**	**$ 32,030**	**$ 26,324**
29	**Field Area Network (FAN)**										
30	Connected Grid Router (CGR)	$ 926,090		$ 926,090		$ 926,090		$ 926,090		$ 926,090	
31	CGR Annual Maint		$ 101,251		$ 101,251		$ 101,251		$ 101,251		$ 101,251
32	Range Extenders (RE/MNB's)	$ 286,605		$ 286,605		$ 286,605		$ 286,605		$ 286,605	
33	Range Extender Annual Maint.		$ 6,948		$ 6,948		$ 6,948		$ 6,948		$ 6,948
34	Annual Cellular Backhaul Service	$ 43,800		$ 43,800		$ 43,800		$ 43,800		$ 43,800	
35	UPPCO Portion of FAN Installation/Site Surveys	$ 432,262		$ 432,262		$ 432,262		$ 432,262		$ 432,262	
36	**Subtotal**	**$ 1,688,757**	**$ 108,199**	**$ 1,688,757**	**$ 108,199**	**$ 1,688,757**	**$ 108,199**	**$ 1,688,757**	**$ 108,199**	**$ 1,688,757**	**$ 108,199**
37	**Endpoints (Meters)**										
38	ITRON RIVA Centron Residential Meters (purchase only)	$ 7,233,994		$ 7,233,994		$ 7,233,994		$ 7,233,994		$ 7,233,994	
39	BSE ITRON AMR Meter Credit	$ (168,000)		$ (168,000)		$ (168,000)		$ (168,000)		$ (168,000)	
40	Residential AMI Meter Install	$ 1,671,828		$ 1,671,828		$ 1,671,828		$ 1,671,828		$ 1,671,828	
41	UPPCO A-base/AMI meter swap	$ 98,912		$ 98,912		$ 148,842		$ 148,842		$ 148,842	
42	**Subtotal**	**$ 8,836,733**	**$ -**	**$ 8,836,733**	**$ -**	**$ 8,886,663**	**$ -**	**$ 8,886,663**	**$ -**	**$ 8,886,663**	**$ -**
43	**Contingency**										
44	5% of CapEx Total	$ 808,517		$ 936,681		$ 887,679		$ 626,843		$ 740,079	
45		**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**	**CapEx**	**O&M**
46	**Total Project Cost**	**$ 17,023,727**	**$ 1,011,325**	**$ 19,715,176**	**$ 953,030**	**$ 18,736,070**	**$ 1,014,045**	**$ 13,258,515**	**$ 730,550**	**$ 15,636,460**	**$ 580,550**

Michigan Public Service Commission
Upper Peninsula Power Company
AMI Project Benefits
OWOC

Case No.: U-20276
Exhibit No.: A-49 (AMI-7)
Schedule:

Witness: Brynick & Haehnel

	Technology	OWOC	
	A	B	C
Line	**Row Labels**	**Sum of Annual Benefits Year 1 - 2**	**Sum of Annual Benefits Year 3 - beyond**
1	**Meter Reading Cost**	**1,547,610**	**1,547,610**
2	Avoided cost of monthly manual meter reads	940,000	940,000
3	Reduced fleet O&M	35,610	35,610
4	Reduction in bi-monthly meter reads	572,000	572,000
5	**Meter Services**	**11,610**	**144,447**
6	Reduction in field services and power quality trips resulting in lower vehicle expenses and labor	-	7,122
7	Reduction in manual disconnect/reconnect of meters and manual off-cycle/special meter reads	-	125,715
8	Reduction in seasonal/temp hires to support field work	11,610	11,610
9	**Outage Management System ("OMS")**	**113,189**	**269,291**
10	Increased efficiencies from less truck rolls during an outage and faster deployment resulting in savings	113,189	269,291
11	**Customer Care**	**452,915**	**452,915**
12	Improvement in late payment charge collection and reduction in uncollectible expense.	187,715	187,715
13	Reduction in customer call volume and back-office costs	88,400	88,400
14	Reduction in estimated bills and associated call volume	176,800	176,800
15	**Grand Total**	**2,125,324**	**2,414,263**

	Technology	MDM	
	A	B	C
Line	**Row Labels**	**Sum of Annual Benefits Year 1 - 2**	**Sum of Annual Benefits Year 3 - beyond**
1	**Meter Reading Cost**	**1,669,132**	**1,669,132**
2	Avoided cost of monthly manual meter reads	940,000	940,000
3	Reduced fleet O&M	42,732	42,732
4	Reduction in bi-monthly meter reads	686,400	686,400
5	**Meter Services**	**11,610**	**410,121**
6	Reduction in field services and power quality trips resulting in lower vehicle expenses and labor	-	21,366
7	Reduction in manual disconnect/reconnect of meters and manual off-cycle/special meter reads	-	377,146
8	Reduction in seasonal/temp hires to support field work	11,610	11,610
9	**Outage Management System ("OMS")**	**113,189**	**269,291**
10	Increased efficiencies from less truck rolls during an outage and faster deployment resulting in savings	113,189	269,291
11	**Customer Care**	**452,915**	**541,315**
12	Improvement in late payment charge collection and reduction in uncollectible expense.	187,715	187,715
13	Reduction in customer call volume and back-office costs	88,400	88,400
14	Reduction in estimated bills and associated call volume	176,800	265,200
15	**Unaccounted For Energy ("UFE")**	**115,000**	**115,000**
16	UFE can be detected early and revenue losses related to unmetered energy can be reduced.	115,000	115,000
17	**Grand Total**	**2,361,846**	**3,004,860**

Michigan Public Service Commission
Upper Peninsula Power Company
AMI Options Customer Payback Analysis

Case No.: U-20276
Exhibit No.: A-51 (AMI-9)
Schedule:
Page: 1 of 1
Witness: Brynick

AMI Options Customer Payback Analysis

Line		Calendar Year	OWOC - On Prem		3-Tier On Prem		2-Tier On Prem		OWOC Hosted		3-Tier Hosted	
1	Cashflow Year 0		(17,023,727)	14 Year Payback	(19,715,176)	11 Year Payback	(18,736,070)	11 Year Payback	(13,258,515)	9 Year Payback	(15,636,460)	8 Year Payback
2												
3	Cashflow (1st two Years)											
4	Fixed O&M*		(1,011,325)		(953,030)		(1,014,045)		(730,550)		(580,550)	
5	Property Tax*		(313,093)		(380,379)		(355,902)		(218,963)		(278,411)	
6	Annual Savings*		2,125,825		2,361,846		2,361,846		2,125,324		2,361,846	
7	Cash Flow Total Yr 1-2***		$ 801,407		$ 1,028,436		$ 991,899		$ 1,175,811		$ 1,502,884	
8												
9	Cashflow (3+ Years)											
10	Fixed O&M*		(1,011,325)		(953,030)		(1,014,045)		(730,550)		(580,550)	
11	Property Tax*		(313,093)		(380,379)		(355,902)		(218,963)		(278,411)	
12	Annual Savings*		2,414,263		3,004,860		3,004,860		2,414,263		3,004,860	
13	Cash Flow Total Yr 3+		$ 1,089,845		$ 1,671,450		$ 1,634,913		$ 1,464,750		$ 2,145,898	
14												
15			4.18%	IRR (20 Years)	7.14%	IRR (20 Years)	7.47%	IRR (20 Years)	10.96%	IRR (20 Years)	13.83%	IRR (20 Years)
16			$ (3,982,285)	NPV (20 Years)	$ (498,350)	NPV (20 Years)	$ (1,229)	NPV (20 Years)	$ 3,767,641	NPV (20 Years)	$ 8,671,849	NPV (20 Years)
17												
18												
19	Year**	Calendar Year	Expected Cash Flow*	Cumulative Cash Flow	Expected Cash Flow*	Cumulative Cash Flow	Expected Cash Flow*	Cumulative Cash Flow	Expected Cash Flow*	Cumulative Cash Flow	Expected Cash Flow*	Cumulative Cash Flow
20	0	2018-2019	(17,023,727)	(17,023,727)	(19,715,176)	(19,715,176)	(18,736,070)	(18,736,070)	(13,258,515)	(13,258,515)	(15,636,460)	(15,636,460)
21	1	2020	801,407	(16,222,320)	1,028,436	(18,686,739)	991,899	(17,744,171)	1,175,811	(12,082,704)	1,502,884	(14,133,575)
22	2	2021	823,846	(15,398,474)	1,057,233	(17,629,507)	1,019,672	(16,724,499)	1,208,734	(10,873,970)	1,544,965	(12,588,610)
23	3	2022	1,183,979	(14,214,494)	1,815,820	(15,813,687)	1,776,127	(14,948,372)	1,591,267	(9,282,704)	2,331,248	(10,257,362)
24	4	2023	1,217,131	(12,997,363)	1,866,663	(13,947,024)	1,825,858	(13,122,514)	1,635,822	(7,646,882)	2,396,523	(7,860,840)
25	5	2024	1,251,210	(11,746,153)	1,918,929	(12,028,094)	1,876,982	(11,245,531)	1,681,625	(5,965,256)	2,463,625	(5,397,214)
26	6	2025	1,286,244	(10,459,909)	1,972,659	(10,055,435)	1,929,538	(9,315,994)	1,728,711	(4,236,546)	2,532,607	(2,864,607)
27	7	2026	1,322,259	(9,137,649)	2,027,894	(8,027,541)	1,983,565	(7,332,429)	1,777,115	(2,459,431)	2,603,520	(261,088)
28	8	2027	1,359,282	(7,778,367)	2,084,675	(5,942,866)	2,039,105	(5,293,324)	1,826,874	(632,557)	2,676,418	2,415,331
29	9	2028	1,397,342	(6,381,024)	2,143,046	(3,799,820)	2,096,200	(3,197,125)	1,878,026	1,245,469	2,751,358	5,166,689
30	10	2029	1,436,468	(4,944,556)	2,203,051	(1,596,769)	2,154,893	(1,042,231)	1,930,611	3,176,080	2,828,396	7,995,085
31	11	2030	1,476,689	(3,467,867)	2,264,737	667,968	2,215,230	1,172,999	1,984,668	5,160,748	2,907,591	10,902,676
32	12	2031	1,518,036	(1,949,831)	2,328,149	2,996,117	2,277,257	3,450,256	2,040,239	7,200,987	2,989,004	13,891,680
33	13	2032	1,560,541	(389,290)	2,393,337	5,389,454	2,341,020	5,791,275	2,097,366	9,298,353	3,072,696	16,964,376
34	14	2033	1,604,237	1,214,947	2,460,351	7,849,805	2,406,568	8,197,844	2,156,092	11,454,445	3,158,731	20,123,108
35	*15* **	2034	1,211,634	2,426,581	1,858,233	9,708,038	1,817,613	10,015,457	1,628,435	13,082,880	2,385,700	22,508,808
36	*16* **	2035	1,245,560	3,672,141	1,910,264	11,618,302	1,868,506	11,883,962	1,674,031	14,756,911	2,452,500	24,961,308
37	*17* **	2036	1,280,436	4,952,577	1,963,751	13,582,053	1,920,824	13,804,787	1,720,904	16,477,815	2,521,170	27,482,477
38	*18* **	2037	1,316,288	6,268,865	2,018,736	15,600,789	1,974,607	15,779,394	1,769,089	18,246,904	2,591,762	30,074,240
39	*19* **	2038	1,353,144	7,622,009	2,075,261	17,676,050	2,029,896	17,809,290	1,818,624	20,065,528	2,664,332	32,738,572
40	*20* **	2039	1,391,032	9,013,041	2,133,368	19,809,418	2,086,733	19,896,023	1,869,545	21,935,073	2,738,933	35,477,505

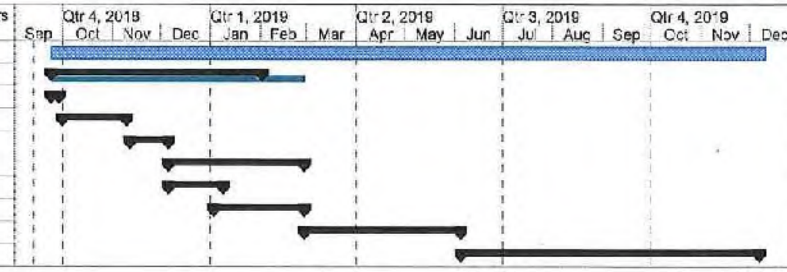
Michigan Public Service Commission
Upper Peninsula Power Company
AMI Revenue Requirement

Case No.:	U-20276
Exhibit No.:	A-52 (AMI-10)
Schedule:	
Page:	1 of 1
Witness:	Brynick

Line	Year	Cumulative Book Value	Accumulated Book Depreciation	Accumulated Deferred Income Taxes	13 Mo. Rolling Average	Return on Rate Base	O&M	Book Depreciation	Income Taxes	Property Tax	Revenue Requirement
1											
2	2018	8,702,990	(150,653)	294,032	4,423,185	335,197	0	150,653	88,140	177,715	751,706
3	2019	15,636,460	(1,025,046)	(759,581)	11,349,101	860,056	0	874,392	226,153	323,193	2,283,794
4	2020	15,636,460	(2,113,618)	(1,001,197)	13,186,739	999,316	(889,068)	1,088,572	262,771	323,193	1,784,784
5	2021	15,636,460	(3,202,190)	(1,015,660)	11,970,128	907,119	(913,962)	1,088,572	238,528	323,193	1,643,450
6	2022	15,636,460	(4,290,762)	(984,850)	10,889,729	825,244	(1,657,666)	1,088,572	216,999	323,193	796,342
7	2023	15,636,460	(5,299,614)	(944,268)	9,876,713	748,476	(1,704,081)	1,008,852	196,812	323,193	573,253
8	2024	14,042,059	(4,363,471)	(949,431)	9,060,868	686,650	(1,751,795)	658,257	180,555	323,193	96,860
9	2025	12,927,713	(3,795,948)	(958,247)	8,451,338	640,458	(1,800,845)	546,823	168,409	323,193	(121,962)
10	2026	12,927,713	(4,342,771)	(963,042)	7,897,710	598,503	(1,851,269)	546,823	157,377	323,193	(225,373)
11	2027	12,927,713	(4,889,593)	(966,994)	7,346,513	556,733	(1,903,105)	546,823	146,393	323,193	(329,963)
12	2028	12,927,713	(5,436,416)	(971,093)	6,795,665	514,988	(1,956,391)	546,823	135,417	323,193	(435,971)
13	2029	12,927,713	(5,983,239)	(975,044)	6,244,817	473,244	(2,011,170)	546,823	124,440	323,193	(543,471)
14	2030	12,927,713	(6,510,570)	(984,160)	5,701,207	432,048	(2,067,483)	527,331	113,607	323,193	(671,303)
15	2031	11,992,118	(5,957,433)	(1,030,419)	5,218,625	395,477	(2,125,373)	382,457	103,991	299,803	(943,644)
16	2032	10,609,732	(4,928,704)	(1,084,238)	4,800,528	363,793	(2,184,883)	353,658	95,660	265,243	(1,106,529)
17	2033	10,609,732	(5,282,362)	(1,091,037)	4,416,561	334,695	(2,246,060)	353,658	88,008	265,243	(1,204,455)
18	2034	10,609,732	(5,636,020)	(1,050,951)	4,079,547	309,156	(2,308,950)	353,658	81,293	265,243	(1,299,600)
19	2035	10,609,732	(5,989,677)	(1,010,876)	3,765,970	285,392	(2,373,600)	353,658	75,044	265,243	(1,394,263)
20	2036	10,609,732	(6,343,335)	(970,790)	3,452,393	261,629	(2,440,061)	353,658	68,796	265,243	(1,490,736)
21	2037	10,609,732	(6,696,993)	(930,715)	3,138,815	237,865	(2,508,383)	353,658	62,547	265,243	(1,589,069)

UPPCO OW Riva SaaS Preliminary Project Plan

ID	Task Name	Duration	Start	Finish	Predecessors
1	UPPCO OW Riva SaaS Project Plan	317 days	Mon 9/24/18	Tue 12/10/19	
2	**Back Office Installation**	95 days	Mon 9/24/18	Fri 2/1/19	
3	**Startup**	5 days	Mon 9/24/18	Fri 9/28/18	
10	**Define**	30 days	Mon 10/1/18	Fri 11/9/18	
21	**Design**	18 days	Mon 11/12/18	Wed 12/5/18	
30	**Build**	60 days	Thu 12/6/18	Wed 2/27/19	
31	**Install / Build enviroments**	24 days	Thu 12/6/18	Tue 1/8/19	
37	**Integration & Interface**	40 days	Thu 1/3/19	Wed 2/27/19	
40	**Network Phase I Installation**	69 days	Thu 2/28/19	Tue 6/4/19	
51	**Full Network and Meter Deployment**	133 days	Wed 6/5/19	Fri 12/6/19	



UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC
(Reformatted Rate Book)

Original Sheet No. C-30.00

C5. Standard Rules & Regulations-Definitions, Technical Terms & Abbreviations

SECTION V - DEFINITIONS, TECHNICAL TERMS AND ABBREVIATIONS

When used in Rates and Standard Rules and Regulations, the following terms shall have the meanings defined below:

A. Applicant - any person, firm or corporation applying for electric service from the Company at one location.

B. Company - Upper Peninsula Power Company acting through its duly authorized officers or employees within the scope of their respective duties.

C. Connected Load - sum of the ratings of the electric power consuming apparatus connected to the installation or system, or part of either, under consideration.

D. Customer - any person, firm or corporation purchasing electric service from the Company under these Rules and Regulations at one location.

E. Demand - the load at the terminals of an installation or system averaged over a specified period of time. Demand is expressed in kilowatts, kilovolt-amperes, or other suitable units.

F. Energy - current consumed, expressed in kilowatt-hours.

G. Estimated Billing - a bill rendered by the Company for energy use which is not calculated or computed by employing an actual reading of a meter or other measuring device.

H. Hp or Horsepower - the nameplate rating of motors or its equivalent in other apparatus. For conversion purposes, one horsepower shall be considered as equivalent to .7457 kilowatt.

I. Kw or Kilowatt - one thousand (1,000) watts.

J. Kwh or Kilowatt-hour - one thousand (1,000) watt-hours.

K. Non-Standard Meter - any electromechanical, analog or digital meter that Company has either left in place per the Customer's election or otherwise deemed Non-Standard by the Company.

~~K~~L. Mo. or Month - the period between any two (2) regular billing periods of approximately thirty (30) day intervals.

~~L~~M. Power Factor - ratio of kilowatts to kilovolt-amperes.

N~~M~~. Service Line - all wiring between the Company's main line or substation transformer terminals and the point of connection to Customer's service entrance.

O~~N~~. Single Service - one set of facilities over which Customer may receive electric power.

P. Standard Meter - all meters that are not deemed a Non-Standard Meter by the Company.

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By G R Haehnel | On and After: 7-21-19
Director of Regulatory Affairs | Issued Under Auth. of
Marquette, Michigan | Mich Public Serv Comm
Dated: xx-xx-xx | In Case No: U-20276
~~Issued: 02-25-08~~ | ~~Effective for Service~~

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C2. Standard Rules & Regulations–Terms and Conditions of Service

SECTION II - TERMS AND CONDITIONS OF SERVICE

A. Membership and Electric Service

Each Applicant for electric service may be required to sign the Company's "Application for Electric Service". Acceptance of service, with or without a signed application, shall be subject to compliance with the terms of the Standard Rules and Regulations and Rate Schedules as filed with the Commission.

B. Ownership and Responsibility

1. Company Owned Facilities - The Company will normally install, own, operate and maintain all distribution facilities on the supply side of the point of attachment as shown on the Company's Standard Drawings, including metering equipment. All service entrance conductor wiring from a point of connection to the Company's service line at a location satisfactory to the Company shall be the responsibility of the customer.

   If building modifications hinder access to metering facilities, create a hazardous condition, or cause a violation of code, the customer will be responsible for all costs incurred by the Company to correct these conditions.

   a. Access to Premises - The customer shall provide at no expense to the Company suitable space with provisions for installation and maintenance of the Company's facilities on the customer's premises. Authorized agents of the Company shall have access to the premises at all reasonable times for construction, operation, maintenance, removal or inspection of the Company's facilities, or to inspect the customer's facilities or measure the customer's load. Authorized employees and agents shall carry identification furnished by the Company and shall display it upon request. Failure to provide access for any of the above reasons may result in termination of service.

   b. Use of Facilities - The Company will not allow use of its poles or other facilities by others for installations or attachments of any kind without written authorization from the Company. This includes, but is not limited to, electrical or communication equipment, lights, signs and fences. The Company assumes no liability for property owned by others attached to its facilities. Unauthorized attachments to Company facilities may be removed by the Company.

   c. Protection - The customer shall use reasonable diligence to protect the Company's facilities located on the customer's premises, and to prevent tampering or interference with such facilities. The Company may discontinue service in accordance with any applicable rules of the Michigan Public Service Commission, in case the meter or wiring on the customer's premises has been tampered with or altered in any manner to allow unmetered or improperly metered energy to be used.

Continued to Sheet No. C-3.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-2.00

In case of such unauthorized use of service, the Company will continue service only after the customer has agreed to pay for the unmetered energy used, pay all costs of discovery and investigation including rewards for discovery, and make provisions and pay charges for an outdoor meter installation or other metering changes as may be required by the Company. Failure to enter into such an agreement or failure to comply with the terms of such an agreement shall be cause to discontinue service in accordance with any applicable rules of the Company or Commission.

Restoration of service will be made upon receipt of reasonable assurance of the customer's compliance with the Company's approved Standard Rules and Regulations.

2. Customer Owned Facilities - The Company reserves the right to deny or terminate service to any customer whose wiring or equipment shall constitute a hazard to the Company's equipment or its service to others. However, it disclaims any responsibility to inspect the customer's wiring, equipment or any subsequent wiring changes or modifications and shall not be held liable for any injury or damage or billing errors resulting from the condition thereof.

   a. The customer shall be responsible for inadequate performance of such facilities. Before purchasing equipment or installing wiring, it shall be the customer's responsibility to check with the Company as to the characteristics of the service available. Any changes required to bring customer's service into compliance with code will be paid for by customer. The Company reserves the right to make reasonable service charges for work performed by Company personnel resulting from malfunction of the customer's facilities.

   b. The customer shall be responsible for notifying the Company of any additions to or changes in the customer's equipment which might exceed the capacity of the Company's facilities, or otherwise affect the quality of service. The customer shall also be responsible for the installation of auxiliary or standby equipment and of alarms and protective devices as required to provide reasonable protection in the event of disturbance or interruption of electrical service. The customer shall install and maintain the necessary devices to protect his equipment against service interruptions and other disturbances on the Company's system, as well as the necessary devices to protect the Company's facilities against overload caused by the customer's equipment. Characteristics and installation of all such equipment or devices shall meet the approval of the Company.

C. Use of Service

Each customer shall, as soon as electric service becomes available, purchase from the Company practically all electric energy used on the premise, and shall become liable for all charges incurred in the purchase of said

Continued to Sheet No. C-4.00

Issued: 12-21-09
By J F Schott
VP Regulatory Affairs
Green Bay, Wisconsin

Effective for Service
On and After: 1-1-10
Issued Under Auth. of
Mich Public Serv Comm
Dated: 12-16-09
In Case No: U-15988

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-3.00

electrical energy from the Company. Standby and/or supplemental on-site generation may be utilized only if approved by the Company and properly connected so as to prevent parallel operations with the Company's system.

1. Notice of Intent

   a. Application - Prior to use of electric service, each customer shall make proper application to the Company, and shall furnish all reasonable information required by the Company. Failure to comply with this requirement may result in refusal by the Company to provide service.

      Any customer using service without first notifying and enabling the Company to establish a beginning meter reading may be held responsible for any amounts due for service supplied to the premises from time of last reading reported immediately preceding his occupancy.

   b. Termination - Any customer desiring termination of service shall so notify the Company a minimum of five (5) working days in advance so the service may be discontinued on a mutually agreeable date. Customers failing to give proper notice of intent to vacate the premises may be held responsible for use of service until a meter reading acceptable to the Company is obtained.

2. Conditions of Use

   The customer shall not use the service in any way that causes a safety hazard, endangers the Company's facilities, or disturbs service to other customers. Failure to comply with this provision may result in discontinuance of the customer's service.

   Customer shall install only such motors or other apparatus or appliances as are suitable for operation with the character of the service supplied by Company, and electric energy must not be used in such a manner as to cause detrimental voltage fluctuations or disturbances in Company's distribution system.

Continued to Sheet No. C-5.00

Issued: 12-21-09
By J F Schott
VP Regulatory Affairs
Green Bay, Wisconsin

Effective for Service
On and After: 1-1-10
Issued Under Auth. of
Mich Public Serv Comm
Dated: 12-16-09
In Case No: U-15988

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-4.00

3. Diversion of Service and Unauthorized Reconnection of Service

When the company determines from reasonable evidence that a customer has obtained electric service, in whole or in part, whether intentionally or not, by means of devices or methods which interfere with the proper metering of such services, the Company reserves the right to estimate and present to such customer for immediate payment a bill to include the following:

a. The deficiency in revenue occasioned by such interference with the proper metering for the entire period of such diversion as determined from inspection of the customer’s meter record and/or the customer’s admission of the duration of such interference or any other evidence indicating the duration and extent of such interference. If the date of the interference cannot be determined, the customer may be back billed in accordance with R 460.3309(4).

b. The cost of any and all damage done to the Company’s equipment due to such interference with its metering.

c. The cost incurred by the Company in investigation and correction of the diversion (such as the cost of installing, reading, testing, and removing meters, and such other incidental costs).

When the company determines from reasonable evidence that a customer has reconnected electric service without authorization, the Company reserves the right to present to such customer for immediate payment a bill to include costs listed in paragraph b. and c. above.

4. Nonstandard Service

Customers shall be liable for the cost of any special installation necessary to meet particular requirements for service at other than standard voltages or for the supply of closer voltage regulation than required by standard practice.

The usual supply of electric service shall be subject to the provision of MPSC rules, but where special service-supply conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its supply terms to meet the peculiar requirements of such case.

The Company reserves the right to make special contractual arrangements as to the provision of necessary service facilities, duration of contract, minimum bills, or other service conditions with respect to customers whose establishments are remote from the Company's existing suitable facilities, or whose service requirements exceeds the capabilities of the Company system in the area, or otherwise necessitate unusual investments by the Company in service facilities or where the permanence of the service is questionable.

Continued to Sheet No. C-6.00

In Case No: U-15988

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

1st Rev. Sheet No. C-6.00
Replaces Original Sheet No. C-6.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-5.00

R 5. Resale of Electric Energy

Customers shall not resell to, or share with others, any electric service furnished by the Company under the terms of its filed rate schedules not applicable to such resale of energy, unless otherwise authorized by the Michigan Public Service Commission or the Company.

R 6. Service to Single Metering Points

Unless otherwise authorized by the Company, electric service will no longer be granted where connection is made to a single metering point for the purpose of resale to the reselling customer's ultimate user. Each user will be metered as an individual unit. For the purposes of this rule, resale will also include sales where the electric service is included in the rent.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation on extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, energy may be purchased by a customer of the Company for resale to others.

Where electric energy is resold with the Company's approval, service to each ultimate user shall be separately metered, and the ultimate user shall be served and charged for such service under the appropriate rate for such service. The Company will be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.

R 7. Point of Attachment

Where suitable service is available, the Company will install service connections from its distribution lines to a suitable point of attachment on the customer's premises designated by the Company. Where the customer requests a point of attachment other than that specified by the Company, and such alternative point of attachment is approved by the Company, the cost of installing additional intermediate supports, wires or fixtures necessary to reach the point of attachment requested by the customer, shall be borne by the customer.

Should it become necessary for any cause beyond the Company's control to change the location of the point of attachment of service connections, the entire cost of any changes in the customer's wiring made necessary thereby shall be borne by the customer.

A service connection will not be made unless the customer has installed his service entrance facilities in compliance with code requirements and specifications set forth by the Company.

Continued to Sheet No. C-7.00

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By J F Schott
VP Regulatory Affairs
Green Bay, Wisconsin

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In Case No: U-15988

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-6.00

The customer may be required to provide at no expense to the Company space for Company facilities on the customer's premises.

For overhead service, the location of the point of attachment must be such that the Company's service conductors can be installed without attachment to the building in any other locations.

For underground service, the point of attachment may be on the building, meter pedestal, or other agreed point.

Service will be provided to meter poles for farm service or other service where more than one structure is to be supplied from a single meter. The customer shall be required to install a fused disconnect switch on the pole at his own expense in accordance with Company specifications.

R 8. Service to House Trailers, Vans, Buses, Used as Dwelling Units

The Company will make service connection to house trailers, vans, buses, or any other dwelling of a mobile nature without special charges, except as specified herein under Section III, when the customer owns the premises and has installed an approved septic tank and well for his own use.

If the above conditions are not met, such installation and service facilities shall be considered to be Temporary Service as applicable under Rule III.B.12.

D. Nature and Quality of Service

The Company will endeavor to, but does not guarantee to furnish a continuous supply of electric energy and to maintain voltage and frequency within reasonable limits.

The Company shall not be liable for interruptions in the service, phase failure or reversal, or variations in the service characteristics, or for any loss or damage of any kind or character occasioned thereby, due to causes or conditions beyond the Company's control, and such causes or conditions shall be deemed to specifically include, but not be limited to, the following: acts or omissions of customers or third parties; operation of safety devices except when such operation is caused by the negligence of the Company, absence of an alternate supply of service; failure, malfunction, breakage, necessary repairs or inspection of machinery, facilities or equipment when the Company has carried on a program of maintenance consistent with the general practices prevailing in the industry; act of God; war; action of the elements; storm or flood; fire; riot; labor dispute or disturbances; or the exercise of authority or regulation by governmental or military authorities.

Continued to Sheet No. C-8.00

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C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-7.00

The customer shall be responsible for giving immediate notice to the Company of interruptions or variations in electric service so that appropriate corrective action can be taken.

The Company reserves the right to temporarily interrupt service for construction, repairs, emergency operations, shortages in power supply, safety and State or National emergencies and shall be under no liability with respect to any such interruption, curtailment or suspension.

E. Metering and Metering Equipment

The customer shall provide, free of expense to the Company and close to the point of service entrance, a space suitable to the Company for the installation of the necessary metering equipment. The customer shall permit only authorized agents of the Company or other persons lawfully authorized to do so, to inspect, test or remove the same. If the meters or metering equipment are damaged or destroyed through the neglect of the customer, the cost of necessary repairs or replacements shall be paid by the customer.

The Company reserves the right to make final decision with respect to methods and equipment used in measurement of loads for billing purposes.

1. Meter Testing - All testing of metering equipment will be done by qualified personnel, either Company employees or by independent agents meeting the requirements of both the Company and the Commission. The Company may, at its option, either conduct field tests on the customer's premises, or remove metering equipment for shop testing.

   a. Routine Tests - The Company will, through test procedures established by the Commission, endeavor to maintain its metering equipment within the accuracy limits prescribed by the Commission.

   b. Tests Requested by Customer - Tests of individual meters will be made upon request of the customer, with payment of a meter test fee in advance of test. The Company reserves the right to refuse to test any meter upon request more frequently than once in six (6) months. If such test reveals meter registration of more than 102% of that of the test equipment, the charge will be refunded and a billing adjustment made. If meter accuracy is found to be within the plus or minus two percent (2%) accuracy range, the charge will not be refunded and a billing adjustment will not be required. When it appears that there may be sufficient reason to question meter accuracy (for example, a marked increase in metered consumption without a corresponding change in a customer's living or working patterns or in the number and kind of appliances or equipment in use on the customer's premises), the Company may waive the meter test charge or it may install a second meter, at no charge to the customer, to provide check readings.

   c. Failure to Register - When a meter has stopped, or has failed to register all of the energy used, the Company will make a charge to the customer for the energy estimated to have been used.

Continued to Sheet No. C-9.00

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Rev. Sheet No. C-9.00
Replaces 1st Rev. Sheet No. C-9.00

C2. Standard Rules & Regulations-Terms and Conditions of Service

Continued from Sheet No. C-8.00

2. Location of Meters - Meters for all single family residential service will be installed outdoors. Meters for other services may be installed outdoors if they are located so they are protected from traffic and are readily accessible for reading and testing. Meters which must be protected from inclement weather while being serviced or tested shall be located indoors or in a suitable housing where such work can be performed.

Meters located indoors shall be as near as possible to the service entrance, in a clean, dry place, reasonably secure from injury, not subject to vibration, and readily accessible for reading and testing.

In cases of multiple buildings such as two-family flats or apartment buildings, if the meters are installed indoors, they shall be located within the premises served or at a common location readily accessible to the tenants and the Company.

An authorized representative of the Company will determine the acceptability of the meter location in all cases.

~~F. Special Charges~~

~~The Company will make such charges for reasonable special services as necessary to discourage abuse, and to minimize subsidy of such services by other customers. The following schedule shall apply where applicable:~~

~~1. Special Meter Readings~~

~~a. When the Company, at the request of the customer:~~

~~(1) Reads a meter on a day other than the scheduled meter reading date, and/or~~

~~(2) Issues a written bill on a day other than the scheduled billing date.~~

~~The customer will be billed a $30.00 charge unless there is a change in the customer of record.~~

~~b. The customer may read his/her meter(s) and provide the reading(s) to the Company. The Company will then calculate the amount due and provide this information to the customer at no cost.~~

3. Non-Standard Meter Provision

a. Customers served on Residential Service have the option to choose a Non-Standard meter. For a customer to be eligible to participate in the Non-Standard Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

b. A customer electing the Non-Standard Meter Provision will have a Non-Standard Meter installed at their premises, have the meter read manually monthly, and be subject to the following charges:

i. Upfront Charge: $62.25, a one-time charge per billing meter per request

ii. Monthly Charge: $14.26, per month charge at each premise as defined by the Company's Standard Rules and Regulations. Multiple metered units shall be charged per billing meter.

c. A Customer whose current meter is a Standard Meter and requests a Non-Standard Meter will pay the Upfront Charge at the time they request this option but will not pay the monthly charge until the Non-Standard Meter is installed.

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Continued to Sheet No. C-10.00

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On and After: ~~1-1-10~~7-21-19
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Issued Under Auth. of
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UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Rev. Sheet No. C-10.00
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C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-9.00

F. Special Charges

The Company will make such charges for reasonable special services as necessary to discourage abuse, and to minimize subsidy of such services by other customers. The following schedule shall apply where applicable:

1. Special Meter Readings

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(1) Reads a meter on a day other than the scheduled meter reading date, and/or

(2) Issues a written bill on a day other than the scheduled billing date.

The customer will be billed a $30.00 charge unless there is a change in the customer of record.

b. The customer may read his/her meter(s) and provide the reading(s) to the Company. The Company will then calculate the amount due and provide this information to the customer at no cost.

Continued to Sheet No. C-11.00

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UPPER PENINSULA POWER COMPANY

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4th Rev. Sheet No. C-11.00
Replaces 3rd Rev. Sheet No. C-11.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-10.00

2. Meter Test Charge $33.00

3. Reconnection Billing – Same Customer
The Company's rate schedules assume continuous use of service for extended periods and do not contemplate temporary disconnection except in those cases where it is requested by seasonal customers or others who occupy premises part of the time. Temporary disconnection by any customer shall not void responsibility for annual minimum charges or payment of the annual monthly fixed charge.
In the event of disconnection, when service is resumed at the same premises by the same customer within a 12-month period, and if there has been no service at such location to another customer during the intervening period, the customer shall be billed the fixed charges* for the disconnection period, plus a charge shall be made according to the following conditions:

a. For the general electric service the charge shall be:

R During Regular Hours** - All Territory Served $60.00
R Outside Regular Hours - All Territory Served $90.00

b. For separately metered service (water heating, space heating, etc.), there shall be no additional charge when such service is reconnected along with the customer's general electric service.

* These fixed charge billings shall not apply to customers disconnected for nonpayment.
** Regular Hours are defined as Monday through Friday, 7:00am to 3:30pm CST (Iron River System) and 7:30am to 4:00pm EDT (Integrated System), not including those days designated as company holidays or legal holidays for New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

c. The appropriate regular or outside regular hours charges will apply in situations when returning to the customer’s location a second (and each subsequent) time to perform required work, when the second (and each subsequent) call is required due to the customer not being present or being ready for the Company to perform the requested work.

4. Unhonored Checks And Electronic Transfers
When a customer issues a check or authorizes an electronic transfer payment to the Company that a bank or other financial institution fails to honor (for reasons of insufficient funds, account closed, stop payment order issued, etc.), the customer shall be billed an additional charge of $20.00 per check or electronic transfer.

5. Connection or Disconnection Outside Regular Working Hours
When application is made for service with the request that meters be connected or disconnected outside regular hours or on Saturdays, Sundays or holidays, the charges specified for reconnections outside regular hours shall apply.

Continued to Sheet No. C-12.00

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

4th Rev. Sheet No. C-11.00
Replaces 3rd Rev. Sheet No. C-11.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-10.00

2. Meter Test Charge $33.00

3. Reconnection Billing - Same Customer
The Company's rate schedules assume continuous use of service for extended periods and do not contemplate temporary disconnection except in those cases where it is requested by seasonal customers or others who occupy premises part of the time. Temporary disconnection by any customer shall not void responsibility for annual minimum charges or payment of the annual monthly fixed charge.
In the event of disconnection, when service is resumed at the same premises by the same customer within a 12-month period, and if there has been no service at such location to another customer during the intervening period, the customer shall be billed the fixed charges* for the disconnection period, plus a charge shall be made according to the following conditions:

a. For the general electric service the charge shall be:

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R Outside Regular Hours - All Territory Served $90.00

b. For separately metered service (water heating, space heating, etc.), there shall be no additional charge when such service is reconnected along with the customer's general electric service.

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C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-11.00

G. Other Conditions of Service

1. Service Disconnect - Service to the customer's premises may be disconnected by the Company under the following conditions:

a. At Customer's Request

(1) Upon Termination - The Company will disconnect service with no charge to the customer upon due notice as provided elsewhere in these rules. However, if restoration of service at the same location is requested by the same customer or property owner(s), a reconnect charge will be applied. The reconnect charge will be increased by the amount of the minimum charge in the applicable rate schedule for the months service was disconnected, provided such reconnect is made during the twelve (12) month period immediately following disconnect.

(2) For Repairs - The Company will temporarily disconnect service to facilitate repairs or other work on the customer's equipment or premises. Special service charges as set forth in Section II, F, will be applicable.

b. At Company's Option - Commercial and Industrial
(Also see Rule II, D)

(1) With Due Notice - The Company may disconnect service upon due notice for any of the following reasons:

(a) For violation of these rules and regulations.

(b) For failure to fulfill contractual obligations.

(c) For failure to provide reasonable access to the customer's premises.

(d) For failure to pay any bill within the established collection period.

(e) For failure to provide deposits as provided elsewhere in these rules.

(f) Upon written notice from governmental inspection authorities of condemnation of the customer's facilities or premises.

(g) For fraudulent representation as to the use of service.

Continued to Sheet No. C-13.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-12.00

(2) Without Notice - The Company reserves the right to disconnect service without notice for any of the following reasons:

(a) Where hazardous conditions exist in the customer's facilities.

(b) Where the customer's use of service adversely affects the Company's facilities or service to other customers.

(c) For unauthorized reconnection after disconnection with due notice.

(d) For unauthorized use of or tampering with the Company's service or facilities.

(3) Reconnect - After service has been discontinued at the Company's option for any of the above reasons, service will be reconnected only after the customer has taken necessary corrective action and made satisfactory arrangement for payment of all fees and charges, including any applicable reconnect fees and deposits to guarantee payment for service.

2. Rate Application - The rates specified in this schedule are predicated upon the delivery of each class of service to a single metering point for the total requirements of each separate premises of the customer, unless otherwise provided for in these rules and regulations. In no case may service be shared with another or transmitted off the premises at which it is delivered. Service at different points and at different premises shall be separately metered and separately billed.

a. Selection of Rates - In some cases the customer is eligible to take service under any one or two or more rates. Upon request, the Company will advise the customer in the selection of the rate which will give him the lowest cost of service, based on the information provided to the Company, but the responsibility for the selection of the rate lies with the customer.

After the customer has selected the rate under which he elects to take service, the customer will not be permitted to change from that rate to another rate until at least twelve months have elapsed. Neither will the customer be permitted to evade this rule by temporarily terminating service. However, the Company may, at its option, waive the provisions of this paragraph where it appears that an earlier change is requested for permanent rather than for temporary or seasonal advantage. The intent of this rule is to prohibit frequent shifts from rate to rate.

No refund will be made of the difference in charges under different rates applicable to the same class of service.

Continued to Sheet No. C-14.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-13.00

b. Apartment Buildings and Multiple Dwellings - An apartment building or multiple dwelling shall be considered as one containing nine or more rooms in which single rooms, suites or groups of rooms have individual cooking and kitchen sink accommodations. Service supplied through a single meter to an apartment building or multiple dwelling containing less than three apartments may be billed on the residential service rates on a single customer basis. Service supplied through a single meter to an apartment building or multiple dwelling containing three or more apartments shall be billed in accordance with the following provisions:

(1) Apartment Buildings or Multiple Dwellings Containing Three or Four Apartments - The customer may have the option of being billed under either the Residential Service Rate, the Residential Electric Heating Service Rate for electric heating customers, or the appropriate General Service or Commercial and Industrial Service Rate. For the purpose of billing under either the Residential Service Rate, or the Residential Electric Heating Service Rate, the initial charge, the kilowatt-hour blocks and the minimum charge shall be multiplied by the number of apartments served through one meter.

(2) Apartment Buildings or Multiple Dwellings Containing Five or More Apartments - The customer shall be billed under the appropriate General Service or Commercial and Industrial Service Rate.

(3) "Master Metering" will be limited to existing customers.

c. Homes or Dormitories for Groups Other Than Private Family Units Service supplied through a single meter to rooming houses, dormitories, nurses' homes, and other similarly occupied buildings containing sleeping accommodations for more than six persons shall be classified as commercial and billed on the appropriate service rate.

d. Farm Service - Service shall be available to farms for residential use under either the Residential Service Rate, or the Residential Electric Heating Service Rate for heating customers, and in addition service may be used through the same meter for any purpose as long as such use is confined to service
R for the culture, processing and handling of products grown and used on the customer's farm. Use of service for purposes other than set forth above shall be served and billed on the
R appropriate Commercial Rate.

Continued to Sheet No. C-15.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-14.00

e. Seasonal Service – A seasonal customer is defined as one who normally occupies premises only during the summer months, or only during the winter months.

3. Power Factor Billing Adjustment
Use of energy by the Customer shall be maintained at a power factor of eighty-five percent (85%). Should the Customer's average power factor fall below eighty-five percent (85%), during the period of maximum use in a billing month, then the demand charge for billing purposes will be adjusted by applying a fraction the numerator of which shall be eighty- five percent (85%) and the denominator the actual power factor. The Company may, at its option, determine the power factor by test or by permanently installed measuring equipment.

H. Budget Billing Plan

1. Definition: The Budget Billing Plan distributes the estimated annual payments required into equal amounts over a 12-month period to lessen the impact of large bills incurred in a few consecutive months.

R R R D
2. Availability: The Budget Billing Plan is available to all prospective and existing year-round residential customers and to all commercial accounts for which the primary purpose of the service is to provide for residential living.

3. Budget Amount and Administration: The monthly budget amount shall be calculated by the Company on the basis of the estimated consumption and estimated applicable rates through the end of the budget year. A budget year begins with the customer's first bill on the budget plan and ends after 12 months.

R R
An applicant for a budget plan shall be informed at the time of application, that budget amounts shall be reviewed and changed at the six, nine, and twelve month billing, if necessary, in order to reflect current circumstances. Adjustments to the budget amount will be made with the objective that the customer's underbilled or overbilled balance in the 12th month of the budget year shall be less than or equal to one-month's budget amount. Customers on the budget payment plan shall be notified of adjustments through either a bill insert or message on the bill. When an adjustment is made to a budget payment amount, the customer will be informed of the adjustment at the same time the bill containing the adjustment is rendered.

Continued to Sheet No. C-16.00

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Rev. Sheet No. C-16.00
Cancels 1st Rev. Sheet No. C-16.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-15.00

Customers who have arrearages shall be allowed to establish a budget payment plan by signing a Settlement Agreement for the arrears. The Settlement Agreement payment amount is not subject to the late payment charge. However, budget payment plans shall be subject to the late payment charge. In addition, if a budget payment is not paid, the customer shall be notified with the next billing that if proper payment is not received subsequent to this notification, the next regular billing may effectuate the removal of the customer from the budget and reflect the appropriate amount due.

At the end of the budget year, if an underbilled or overbilled balance exists in a customer's account, the balance shall be handled as follows:

R a. A customer's debit balance will be applied to the final bill for the
R budget year and become due or, at the customer's option, will be paid in full or on a deferred basis.

R b. A customer's credit balance will be applied against the customer's
R account or, at the customer's option, a refund will be made. If a
R customer has a credit balance of more than $10 at the end of the program year, upon the request of the customer, the utility shall return the credit balance.

D

4. Determination of Budget Amount: The regular budget amount is determined by taking the actual energy related bill amount and dividing this by the number of billing days in the period to get average cost per day. This average cost per day is then multiplied by 30 to determine a monthly amount. The monthly amount may be multiplied by a multiplier for rates and a multiplier for weather.

5. Billing Method: The difference between actual service used and the budget amount is calculated monthly during the budget year. The adjustment may be a charge or credit to make the amount due for current service, including yard lighting, equal to the budget amount. The adjustment is printed on all bills during the customer's budget year.

All budget accounts are billed as scheduled each month. The readings are estimated if an actual reading is not obtained. The adjustment to any "late cycle" billing of budget accounts is made equal to the amount of the billing, since the budget amount has already been billed.

Continued to Sheet No. C-17.00

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By Susan Devon
Director Regulatory Affairs
Marquette, Michigan

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Dated: 02-23-2016
In Case No: U-17995

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Rev. Sheet No. C-17.00
Replaces 1st Rev. Sheet No. C-17.00

C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-16.00

R R The difference between the actual billing and budget amount (the adjustment) is accumulated each month and noted on the bottom of the bill and may be a charge or credit.

R R The amount remaining is applied to the bill due at the end of the customer's budget year unless the customer discontinues service before that time or the budget is canceled. If the budget amount is accurate, the weather is normal, and there are no rate or tax changes, the balance should be roughly equal to the budget amount. The budget balance is applied to the final bill if the customer discontinues service.

I. Preferred Due Date Billing Service

R 1. Available to residential, and small commercial customers.

2. Upon request by a customer, the Company will set the electric service bill due date as requested by the customer. The customer can choose the following options for their bill due date:

D

a. 10, 15, or 20 days from the bill mail date.

3. Customers will be removed from the Preferred Due Date Billing Service if payment is not received by the date of the billing of the 2^{nd} billing cycle. Customers can return to the Preferred Due Date Billing Service upon working out payment arrangements with the Company.

D
R 4. Once a Preferred Due Date is selected, customers may change their Preferred Due Date only once per calendar year.

Continued to Sheet No. C-18.00

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Director of Regulatory Affairs
Marquette, Michigan

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C2. Standard Rules & Regulations–Terms and Conditions of Service

Continued from Sheet No. C-17.00

R 5. Except as provided by the Preferred Due Date Billing Service, all other practices relating to the Discontinuation of Service will be provided in accordance with the Consumer Standards and Billing Practices for Residential Electric Service, and the Billing Practices Applicable to Commercial and Industrial Electric Customers.

J. Billing for Fractional Month's Electric Service

When a customer's use of service is for a fractional month, the Company will, unless specific provision would conflict, prorate the bill for the period on the following basis:

1. Block Type Rates

   a. Initial Bills
      (i) 10 days or less - include consumption in next billing
      (ii) 11 days to 24 days inclusive - prorate on a daily basis
      (iii) 25 days to 35 days inclusive - bill as one month
      (iv) Over 35 days - prorate on a daily basis

   b. Pick-Up Billing
      (i) 25 to 35 days inclusive - bill as one month
      (ii) All others - prorate on a daily basis

   c. Final Bills
      (i) 25 to 35 days inclusive - bill as one month
D   (ii) All others - prorate on a daily basis
R

2. Demand Type, Street Lighting, and Outdoor Lighting
   Prorate part-months bills on a daily basis

3. Temporary Customers
   Customers whose total length of service is less than 30 days - bill as one month

4. Annual Minimums
   Prorate part year on a monthly basis

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 100 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Montana, Nebraska, New Mexico, Ohio, Oregon, South Dakota, Virginia, Washington, West Virginia, and Wyoming.[1] My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute and the CFA Society of Austin. A resume containing the details of my qualifications and experience is attached below.

[1] Over the course of my career, I have supported the preparation of prefiled testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states. This testimony was sponsored by Dr. William Avera, who was formerly President of FINCAP, Inc.

ADRIEN M. McKENZIE

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

ROE ANALYSES

SUMMARY OF RESULTS

	Average		Midpoint
DCF			
Value Line	10.3%		11.7%
IBES	10.2%		11.0%
Zacks	9.8%		10.0%
Bloomberg	9.7%		10.0%
S&P Capital/IQ	10.1%		11.0%
FactSet	9.7%		10.4%
Internal br + sv	9.7%		11.8%
CAPM			
Current Bond Yield	11.0%		10.8%
Projected Bond Yield	11.2%		11.2%
Empirical CAPM			
Current Bond Yield	11.8%		11.7%
Projected Bond Yield	12.0%		12.0%
Utility Risk Premium			
Current Bond Yield		9.9%	
Projected Bond Yields		11.0%	
Expected Earnings			
Industry		10.7%	
Proxy Group	10.9%		11.6%

Recommended Cost of Equity			
Cost of Equity Range	**9.8%**	**--**	**10.8%**

REGULATORY MECHANISMS

UTILITY GROUP

	Holding Company	Type of Adjustment Clause										
				Decoupling				New Capital				
		Elec. Fuel/ Purch. Pwr	Conserv. Program Expense	Full	Partial	Renew-ables Expense	Environ-mental Compliance	Gener-ation Capacity	Generic Infra-structure	Trans-mission Expense	Other	Future Test Year
1	Algonquin Pwr & Util	√	- -	- -	√	- -	√	- -	√	√	Taxes, franchise fees; Renewables mechanism available	P
2	Ameren Corp.	√	√	- -	√	√	√	- -	√	√	Taxes, franchise fees, bad debts	O,P
3	AVANGRID, Inc.	D	√	√	- -	√	- -	D	- -	- -	Storm costs	C
4	Black Hills Corp.	√	√	- -	√	√	√	√	√	√		O
5	CMS Energy Corp.	√	√	- -	- -	√	- -	- -	- -	√		C
6	DTE Energy Co.	√	√	- -	- -	√	- -	- -	- -	√		C
7	El Paso Electric Co.	√	√	- -	- -	- -	- -	√	- -	- -	Military base discounts	- -
8	Emera Inc.	√	√	- -	- -	- -	√	√	- -	- -	Franchise fees, gross receipts taxes	C
9	Entergy Corp.	√	√	- -	√	- -	√	√	√	√	Taxes, franchise fees, storm costs	O,P
10	Exelon Corp.	D	√	√	√	√	√	D	√	√	Taxes, franchise fees, bad debts, nuclear decomm., societal benefits	O,P
11	FirstEnergy Corp.	D	√	- -	√	√	√	- -	√	√	Taxes, fees, low-income assistance, societal benefits, uncollectibles	O,P
12	IDACORP, Inc.	√	√	√	- -	- -	- -	- -	- -	- -		P
13	NorthWestern Corp.	√	√	- -	- -	- -	- -	- -	- -	- -	Purchased power contracts	- -
14	PNM Resources	√	√	- -	- -	√	√	- -	√	√	Taxes, franchise fees	O
15	Otter Tail Corp.	√	√	- -	- -	√	√	- -	- -	√		C
16	Pub Sv Enterprise Grp.	D	√	- -	- -	√	√	D	√	- -	Taxes, franchise fees, societal benefits	P
17	Sempra Energy	√	- -	√	- -	- -	- -	- -	- -	- -		C

Sources:

Exhibit 58, pages 2-4, contain operating company data that are aggregated into the parent company data on this page.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

REGULATORY MECHANISMS

UTILITY GROUP OPERATING COS.

Holding Company/ Operating Company	Type of Svc	State	Type of Adjustment Clause (a): Elec. Fuel/ Gas/ Purch. Pwr	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	Renew-ables Expense	Environ-mental Compliance	New Capital Tracker: Gener-ation Capacity	New Capital Tracker: Generic Infra-structure	Trans-mission Expense	Other	Future Test Year (b)
ALGONQUIN PWR. & UTIL.													
Empire District Electric	Elec.	MO	√	- -	- -	- -	- -	√	- -	- -	√	√	P
Liberty Utilities	Elec.	NH	D	- -	- -	√	- -	- -	D	√	- -	- -	- -
AMEREN													
Ameren Illinois	Elec.	IL	D	√	- -	- -	√	√	D	- -	√	√	O
Union Electric	Elec.	MO	√	√	- -	√	- -	√	- -	√	√	√	P
AVANGRID													
Central Maine Pwr	Elec.	ME	D	- -	√	- -	- -	- -	D	- -	- -	√	C
NY State E&G	Elec.	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
Rochester G&E	Elec.	NY	D	- -	√	- -	√	- -	D	- -	- -	- -	C
United Illuminating	Elec.	CT	D	√	√	- -	- -	- -	D	- -	√	- -	C
BLACK HILLS CORP.													
BH Power	Elec.	SD	√	√	- -	√	- -	√	- -	- -	√	√	- -
Cheyenne Light	Elec.	WY	√	√	- -	√	√	- -	- -	- -	- -	√	O
BH Colorado Elec	Elec	CO	√	√	- -	- -	√	- -	√	√	- -	√	- -
CMS ENERGY													
Consumers Energy	Elec.	MI	√	√	- -	- -	√	- -	- -	- -	√	- -	C
DTE ENERGY													
DTE Electric	Elec.	MI	√	√	- -	- -	√	- -	- -	- -	√	- -	C
EL PASO ELECTRIC													
El Paso Electric	Elec.	TX	√	√	- -	- -	- -	- -	- -	√	- -	√	- -
EMERA INC.													
Emera Maine	Elec.	ME	D	- -	- -	- -	- -	- -	D	- -	- -	- -	C
Tampa Electric Co.	Elec.	FL	√	√	- -	- -	- -	√	√	- -	- -	√	C

REGULATORY MECHANISMS

UTILITY GROUP OPERATING COS.

			Type of Adjustment Clause (a)										
					Decoupling				New Capital Tracker				
Holding Company/ Operating Company	**Type of Svc**	**State**	**Elec. Fuel/ Gas/ Purch. Pwr**	**Conserv. Program Expense**	**Full**	**Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other**	**Future Test Year (b)**
ENTERGY CORP.													
Entergy Arkansas Inc.	Elec.	AR	√	√	- -	√	- -	- -	√	√	√	√	P
Entergy Louisiana LLC	Elec.	LA	√	√	- -	√	- -	√	√	- -	√	√	O
Entergy Mississippi Inc.	Elec.	MS	√	√	- -	√	- -	√	- -	- -	√	√	O
Entergy New Orleans Inc.	Elec.	LA	√	√	- -	√	- -	√	√	- -	√	√	O
Entergy Texas Inc.	Elec.	TX	√	√	- -	- -	- -	- -	- -	√	√	√	- -
EXELON CORP.													
Baltimore G&E	Elec.	MD	D	√	√	- -	- -	- -	D	√	- -	√	P
Commonwealth Edison	Elec.	IL	D	√	- -	- -	√	√	D	√	√	√	O
PECO Energy	Elec.	PA	D	√	- -	- -	- -	- -	D	√	- -	√	O
Atlantic City Electric	Elec.	NJ	D	√	- -	- -	√	√	D	- -	- -	√	P
Delmarva P&L	Elec.	MD	D	√	√	- -	- -	- -	D	√	- -	- -	P
Potomac Electric Pwr	Elec.	DC	D	- -	- -	√	√	- -	D	√	- -	√	P
FIRSTENERGY CORP.													
Cleveland Elec. Illuminating Co.	Elec.	OH	D	√	- -	√	√	- -	D	√	√	√	P
Jersey Central Power & Light Co.	Elec.	NJ	D	√	- -	- -	√	√	D	- -	- -	√	P
Metropolitan Edison Co.	Elec.	PA	D	√	- -	- -	- -	- -	D	√	√	√	O
Monongahela Power Co.	Elec.	WV	√	√	- -	- -	- -	- -	- -	√	- -	√	- -
Ohio Edison Co.	Elec.	OH	D	√	- -	√	√	- -	D	√	√	√	P
Pennsylvania Electric Co.	Elec.	PA	D	√	- -	- -	- -	- -	D	√	√	√	O
The Potomac Edison Co.	Elec.	MD	D	√	- -	- -	- -	- -	D	- -	- -	√	O
Toledo Edison Co.	Elec.	OH	D	√	- -	√	√	- -	D	√	√	√	P
West Penn Power Co.	Elec.	PA	D	√	- -	- -	- -	- -	D	√	- -	√	O
IDACORP													
Idaho Power	Elec.	ID	√	√	√	- -	- -	- -	- -	- -	- -	- -	P
NORTHWESTERN CORP. (c)													
NorthWestern Corp.	Elec.	MT	√	√	- -	- -	- -	- -	- -	- -	- -	√	- -
NorthWestern Corp.	Elec.	SD	√	√	- -	- -	- -	- -	- -	- -	- -	- -	- -
OTTER TAIL CORP.													

REGULATORY MECHANISMS

UTILITY GROUP OPERATING COS.

			Type of Adjustment Clause (a)										
					Decoupling				New Capital Tracker				
Holding Company/ Operating Company	**Type of Svc**	**State**	**Elec. Fuel/ Gas/ Purch. Pwr**	**Conserv. Program Expense**	**Full**	**Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other**	**Future Test Year (b)**
Otter Tail Power	Elec.	MN	√	√	- -	- -	√	√	- -	- -	√	- -	C
PNM RESOURCES													
Public Service Company of New Mexico	Elec.	NM	√	√	- -	- -	√	√	- -	√	- -	√	O
Texas-New Mexico Power Co.	Elec.	TX	√	√	- -	- -	- -	- -	- -	√	√	√	- -
PUB SV ENTERPRISE GRP													
Pub Service E&G	Elec.	NJ	D	√	- -	- -	√	√	D	√	- -	√	P
SEMPRA ENERGY													
San Diego Gas & Electric	Elec.	CA	√	- -	√	- -	- -	- -	- -	- -	- -	- -	C

Sources:

(a) Regulatory Research Associates, Regulatory Focus, *"Adjustment Clauses-A State-by-State Overview,"* Sep. 12, 2017.

(b) Edison Electric Institute, *"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"* Nov. 11, 2015.

(c) NorthWestern Corp. is not a holding company, with its Montana and South Dakota operations representing its major divisions.

Notes:

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

LIR - Limited issue reopeners.

CAPITAL STRUCTURE

UTILITY GROUP

		At Fiscal Year-End 2017 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Other**	**Common Equity**
1	Algonquin Pwr & Util	48.1%	2.7%	49.2%	n/a	n/a	n/a
2	Ameren Corp.	52.0%	0.0%	48.0%	49.0%	1.0%	50.0%
3	Avangrid, Inc.	26.3%	0.0%	73.7%	36.5%	0.0%	63.5%
4	Black Hills Corp.	63.1%	0.0%	36.9%	54.0%	0.0%	46.0%
5	CMS Energy Corp.	69.5%	0.0%	30.5%	62.0%	0.5%	37.5%
6	DTE Energy Co.	55.2%	0.0%	44.8%	57.0%	0.0%	43.0%
7	El Paso Electric Co.	51.2%	0.0%	48.8%	54.5%	0.0%	45.5%
8	Emera Inc.	65.9%	3.4%	30.7%	59.8%	3.3%	36.9%
9	Entergy Corp.	64.8%	0.9%	34.4%	60.0%	0.5%	39.5%
10	Exelon Corp.	51.6%	0.0%	48.4%	50.0%	0.0%	50.0%
11	FirstEnergy Corp.	85.0%	0.0%	15.0%	67.0%	0.0%	33.0%
12	IDACORP, Inc.	43.6%	0.0%	56.4%	44.0%	0.0%	56.0%
13	NorthWestern Corp.	50.0%	0.0%	50.0%	46.0%	0.0%	54.0%
14	Otter Tail Corp.	41.3%	0.0%	58.7%	41.0%	0.0%	59.0%
15	PNM Resources	57.9%	0.3%	41.8%	54.0%	0.5%	45.5%
16	Pub Sv Enterprise Grp.	48.6%	0.0%	51.4%	49.5%	0.0%	50.5%
17	Sempra Energy	55.8%	0.1%	44.1%	55.0%	0.0%	45.0%
	Average	**54.7%**	**0.4%**	**44.9%**	**52.5%**	**0.4%**	**47.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.

CAPITAL STRUCTURE

ELECTRIC GROUP OPERATING SUBSIDIARIES

	At Year-End 2017		
Operating Company	**Debt**	**Preferred**	**Common Equity**
ALGONQUIN PWR. & UTIL.			
Empire District Electric	48.5%	0.0%	51.5%
Liberty Utilities (Granite State Elec.)	25.4%	0.0%	74.6%
AMEREN CORP.			
Ameren Illinois Co.	46.1%	1.0%	52.9%
Union Electric Co.	49.3%	1.0%	49.8%
AVANGRID			
Central Maine Pwr	37.6%	0.0%	62.4%
NY State E&G	51.2%	0.0%	48.8%
Rochester G&E	45.7%	0.0%	54.3%
United Illuminating	45.7%	0.0%	54.3%
BLACK HILLS CORP.			
Black Hills Power	47.1%	0.0%	52.9%
Cheyenne Light Fuel & Power	46.7%	0.0%	53.3%
Black Hills/Colorado Electric Utility Co	47.8%	0.0%	52.2%
CMS ENERGY			
Consumers Energy Co.	47.7%	0.3%	52.0%
DTE ENERGY CO.			
DTE Electric Co.	49.0%	0.0%	51.0%
EL PASO ELECTRIC			
El Paso Electric Co.	51.2%	0.0%	48.8%
EMERA INC.			
Emera Maine	35.1%	0.0%	64.8%
Tampa Electric Co.	44.3%	0.0%	55.7%
ENTERGY CORP.			
Entergy Arkansas Inc.	55.1%	0.6%	44.3%
Entergy Louisiana LLC	53.6%	0.0%	46.4%
Entergy Mississippi Inc.	51.5%	0.8%	47.7%
Entergy New Orleans Inc.	50.3%	0.0%	49.7%
Entergy Texas Inc.	55.7%	0.0%	44.3%

CAPITAL STRUCTURE

ELECTRIC GROUP OPERATING SUBSIDIARIES

	At Year-End 2017-Continued		
Operating Company	**Debt**	**Preferred**	**Common Equity**
EXELON CORP.			
Delmarva Power and Light	49.3%	0.0%	50.7%
Baltimore Gas & Electric Co.	45.1%	0.0%	54.9%
Commonweath Edison Co.	44.3%	0.0%	55.7%
PECO Energy Co.	44.8%	0.0%	55.2%
Potomac Electric Power Co.	50.1%	0.0%	49.9%
Atlantic City Electric Co.	51.8%	0.0%	48.2%
FIRSTENERGY CORP.			
The Allegheny Generating Company	38.1%	0.0%	61.9%
Cleveland Elec. Illuminating Co.	49.1%	0.0%	50.9%
Jersey Central Power & Light Co.	40.8%	0.0%	59.2%
Metropolitan Edison Co.	49.7%	0.0%	50.3%
MONONGAHELA POWER CO.	50.9%	0.0%	49.1%
Ohio Edison Co.	36.3%	0.0%	63.7%
Pennsylvania Electric Co.	48.1%	0.0%	51.9%
The Potomac Edison Co.	49.9%	0.0%	50.1%
Toledo Edison Co.	38.0%	0.0%	62.0%
WEST PENN POWER CO.	47.4%	0.0%	52.6%
IDACORP			
Idaho Power Co.	45.6%	0.0%	54.4%
NORTHWESTERN CORP.			
NorthWestern Corporation	50.0%	0.0%	50.0%
OTTER TAIL CORP.			
Otter Tail Power Co.	44.9%	0.0%	55.1%
PNM RESOURCES			
Public Service Company of New Mexico	52.8%	0.4%	46.8%
Texas-New Mexico Power Co.	43.1%	0.0%	56.9%
PUB SV ENTERPRISE GRP.			
Pub Service Electric & Gas Co.	44.4%	0.0%	55.6%
SEMPRA ENERGY			
San Diego Gas & Electric	49.7%	0.0%	50.3%
Minimum	**25.4%**	**0.0%**	**44.3%**
Maximum	**55.7%**	**1.0%**	**74.6%**
Simple Average	**46.6%**	**0.1%**	**53.3%**
Weighted Average	**47.6%**	**0.1%**	**52.3%**

Sources: Most recent Company 10-K and FERC Form 1 reports.

DCF MODEL - UTILITY GROUP

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	Algonquin Pwr & Util	$9.75	$0.47	4.8%
2	Ameren Corp.	$57.18	$1.88	3.3%
3	Avangrid, Inc.	$51.90	$1.75	3.4%
4	Black Hills Corp.	$57.15	$1.93	3.4%
5	CMS Energy Corp.	$44.60	$1.48	3.3%
6	DTE Energy Co.	$100.10	$3.72	3.7%
7	El Paso Electric Co.	$56.46	$1.44	2.6%
8	Emera Inc.	$40.45	$2.26	5.6%
9	Entergy Corp.	$78.22	$3.62	4.6%
10	Exelon Corp.	$40.44	$1.45	3.6%
11	FirstEnergy Corp.	$33.76	$1.44	4.3%
12	IDACORP, Inc.	$89.53	$2.44	2.7%
13	NorthWestern Corp.	$53.53	$2.23	4.2%
14	Otter Tail Corp.	$45.22	$1.36	3.0%
15	PNM Resources	$38.00	$1.09	2.9%
16	Pub Sv Enterprise Grp.	$51.39	$1.82	3.5%
17	Sempra Energy	$106.45	$3.65	3.4%
	Average			**3.7%**

(a) Average of closing prices for 30 trading days ended Jun. 15, 2018.

(b) The Value Line Investment Survey, Summary & Index (Jun. 15, 2018).

DCF MODEL - UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Earnings Growth						
	Company	V Line	IBES	Zacks	Bloomberg	S&P Capital IQ	FactSet	br+sv Growth
1	Algonquin Pwr & Util	n/a	10.0%	8.0%	8.0%	10.1%	17.6%	n/a
2	Ameren Corp.	7.5%	6.3%	6.5%	9.0%	6.6%	9.0%	4.8%
3	Avangrid, Inc.	13.0%	10.4%	9.1%	9.2%	9.2%	9.7%	2.0%
4	Black Hills Corp.	5.0%	3.9%	4.1%	4.9%	4.9%	5.3%	5.4%
5	CMS Energy Corp.	7.0%	7.1%	6.4%	6.3%	7.0%	6.9%	6.2%
6	DTE Energy Co.	7.0%	5.6%	5.3%	5.3%	5.8%	5.4%	5.4%
7	El Paso Electric Co.	4.5%	5.2%	5.1%	5.1%	5.1%	5.1%	3.6%
8	Emera Inc.	8.5%	7.4%	n/a	13.4%	7.0%	12.2%	5.2%
9	Entergy Corp.	2.0%	-6.7%	7.0%	0.9%	7.0%	-1.0%	5.9%
10	Exelon Corp.	8.0%	4.2%	5.7%	5.3%	3.6%	4.8%	5.3%
11	FirstEnergy Corp.	3.0%	-6.9%	6.0%	-0.1%	-2.6%	-0.3%	12.2%
12	IDACORP, Inc.	3.5%	3.1%	3.9%	4.5%	3.9%	3.9%	3.2%
13	NorthWestern Corp.	3.5%	3.2%	3.0%	2.4%	3.0%	2.4%	3.6%
14	Otter Tail Corp.	7.5%	9.0%	n/a	7.5%	7.5%	6.0%	6.5%
15	PNM Resources	7.5%	4.3%	5.1%	5.1%	5.6%	5.5%	4.4%
16	Pub Sv Enterprise Grp.	4.0%	6.5%	6.1%	6.6%	6.4%	6.7%	4.6%
17	Sempra Energy	8.5%	9.7%	8.8%	17.0%	8.1%	27.3%	7.4%

(a) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.
(b) www.finance.yahoo.com (retrieved Jun. 14, 2018).
(c) www.zacks.com (retrieved Jun. 15, 2018).
(d) Bloomberg L.P. (retrieved Jun. 5, 2018).
(e) SNL Financial (retrieved Jun. 5, 2018).
(f) FactSet (retrieved Jun. 5, 2018).
(g) See Exhibit 61.

DCF MODEL - UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)	(a)	(a)
		Earnings Growth						
	Company	**V Line**	**IBES**	**Zacks**	**Bloomberg**	**S&P Capital/IQ**	**FactSet**	**br+sv Growth**
1	Algonquin Pwr & Util	n/a	14.8%	12.8%	12.8%	14.9%	22.4%	n/a
2	Ameren Corp.	10.8%	9.6%	9.8%	12.3%	9.9%	12.3%	8.1%
3	Avangrid, Inc.	16.4%	13.8%	12.5%	12.6%	12.6%	13.1%	5.4%
4	Black Hills Corp.	8.4%	7.2%	7.5%	8.3%	8.3%	8.7%	8.8%
5	CMS Energy Corp.	10.3%	10.4%	9.7%	9.6%	10.3%	10.2%	9.5%
6	DTE Energy Co.	10.7%	9.3%	9.0%	9.0%	9.5%	9.1%	9.1%
7	El Paso Electric Co.	7.1%	7.8%	7.7%	7.7%	7.7%	7.7%	6.2%
8	Emera Inc.	14.1%	13.0%	n/a	19.0%	12.6%	17.8%	10.8%
9	Entergy Corp.	6.6%	-2.1%	11.6%	5.5%	11.6%	3.6%	10.5%
10	Exelon Corp.	11.6%	7.8%	9.3%	8.9%	7.2%	8.4%	8.9%
11	FirstEnergy Corp.	7.3%	-2.7%	10.3%	4.1%	1.6%	4.0%	16.4%
12	IDACORP, Inc.	6.2%	5.8%	6.6%	7.2%	6.6%	6.6%	6.0%
13	NorthWestern Corp.	7.7%	7.3%	7.2%	6.6%	7.2%	6.6%	7.8%
14	Otter Tail Corp.	10.5%	12.0%	n/a	10.5%	10.5%	9.0%	9.5%
15	PNM Resources	10.4%	7.2%	8.0%	8.0%	8.5%	8.4%	7.2%
16	Pub Sv Enterprise Grp.	7.5%	10.0%	9.7%	10.2%	10.0%	10.2%	8.1%
17	Sempra Energy	11.9%	13.1%	12.2%	20.4%	11.5%	30.7%	10.9%
	Average (b)	**10.3%**	**10.2%**	**9.8%**	**9.7%**	**10.1%**	**9.7%**	**9.7%**
	Midpoint (b,c)	**11.7%**	**11.0%**	**10.0%**	**10.0%**	**11.0%**	**10.4%**	**11.8%**

(a) Sum of dividend yield (Exhibit 60, p. 1) and respective growth rate (Exhibit 60, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2022					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**n/a**
2	Ameren Corp.	$4.00	$2.35	$37.50	41.3%	10.7%	1.0264	10.9%	4.5%	0.0092	0.3478	0.32%	**4.8%**
3	Avangrid, Inc.	$3.25	$2.20	$53.25	32.3%	6.1%	1.0090	6.2%	2.0%	(0.0000)	(0.0143)	0.00%	**2.0%**
4	Black Hills Corp.	$4.00	$2.45	$41.25	38.8%	9.7%	1.0359	10.0%	3.9%	0.0362	0.4107	1.49%	**5.4%**
5	CMS Energy Corp.	$3.00	$1.85	$22.25	38.3%	13.5%	1.0391	14.0%	5.4%	0.0165	0.4765	0.78%	**6.2%**
6	DTE Energy Co.	$7.50	$4.55	$69.00	39.3%	10.9%	1.0345	11.2%	4.4%	0.0262	0.3581	0.94%	**5.4%**
7	El Paso Electric Co.	$3.00	$1.85	$33.50	38.3%	9.0%	1.0187	9.1%	3.5%	0.0032	0.3619	0.12%	**3.6%**
8	Emera Inc.	$4.20	$3.00	$34.80	28.6%	12.1%	1.0192	12.3%	3.5%	0.0315	0.5360	1.69%	**5.2%**
9	Entergy Corp.	$6.75	$3.90	$56.00	42.2%	12.1%	1.0306	12.4%	5.2%	0.0198	0.3212	0.64%	**5.9%**
10	Exelon Corp.	$3.75	$1.70	$39.75	54.7%	9.4%	1.0266	9.7%	5.3%	0.0039	0.1167	0.05%	**5.3%**
11	FirstEnergy Corp.	$2.75	$1.60	$18.00	41.8%	15.3%	1.0931	16.7%	7.0%	0.0941	0.5500	5.18%	**12.2%**
12	IDACORP, Inc.	$4.75	$3.05	$53.25	35.8%	8.9%	1.0172	9.1%	3.2%	(0.0001)	0.3129	0.00%	**3.2%**
13	NorthWestern Corp.	$4.00	$2.60	$42.75	35.0%	9.4%	1.0195	9.5%	3.3%	0.0095	0.3160	0.30%	**3.6%**
14	Otter Tail Corp.	$2.60	$1.55	$24.45	40.4%	10.6%	1.0435	11.1%	4.5%	0.0418	0.4853	2.03%	**6.5%**
15	PNM Resources	$2.50	$1.35	$27.00	46.0%	9.3%	1.0274	9.5%	4.4%	-	0.1692	0.00%	**4.4%**
16	Pub Sv Enterprise Grp.	$3.75	$2.20	$34.75	41.3%	10.8%	1.0233	11.0%	4.6%	-	0.3381	0.00%	**4.6%**
17	Sempra Energy	$7.75	$4.90	$71.00	36.8%	10.9%	1.0505	11.5%	4.2%	0.0655	0.4929	3.23%	**7.4%**

DCF MODEL - UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
			2017			2022		Chg		2022 Price				Common Shares	
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2017	2022	Growth
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	Ameren Corp.	49.8%	$14,420	$7,181	50.0%	$18,700	$9,350	5.4%	$65.00	$50.00	$57.50	1.533	242.63	250.00	0.60%
3	Avangrid, Inc.	74.4%	$20,273	$15,083	63.5%	$26,000	$16,510	1.8%	$60.00	$45.00	$52.50	0.986	309.01	309.00	0.00%
4	Black Hills Corp.	35.5%	$4,818	$1,711	46.0%	$5,325	$2,450	7.4%	$80.00	$60.00	$70.00	1.697	53.54	59.50	2.13%
5	CMS Energy Corp.	32.4%	$13,692	$4,436	37.5%	$17,500	$6,563	8.1%	$50.00	$35.00	$42.50	1.910	281.65	294.00	0.86%
6	DTE Energy Co.	43.8%	$21,697	$9,503	43.0%	$31,200	$13,416	7.1%	$125.00	$90.00	$107.50	1.558	179.39	195.00	1.68%
7	El Paso Electric Co.	48.8%	$2,338	$1,141	45.5%	$3,025	$1,376	3.8%	$60.00	$45.00	$52.50	1.567	40.58	41.00	0.21%
8	Emera Inc.	31.8%	$20,321	$6,471	36.9%	$21,250	$7,840	3.9%	$85.00	$65.00	$75.00	2.155	228.77	246.00	1.46%
9	Entergy Corp.	35.5%	$22,528	$7,997	39.5%	$27,500	$10,863	6.3%	$100.00	$65.00	$82.50	1.473	180.52	193.00	1.35%
10	Exelon Corp.	47.8%	$62,422	$29,838	50.0%	$77,900	$38,950	5.5%	$55.00	$35.00	$45.00	1.132	963.34	980.00	0.34%
11	FirstEnergy Corp.	15.7%	$25,040	$3,931	33.0%	$30,300	$9,999	20.5%	$50.00	$30.00	$40.00	2.222	445.33	548.00	4.24%
12	IDACORP, Inc.	56.3%	$3,998	$2,251	56.0%	$4,775	$2,674	3.5%	$90.00	$65.00	$77.50	1.455	50.42	50.40	-0.01%
13	NorthWestern Corp.	49.8%	$3,615	$1,800	54.0%	$4,050	$2,187	4.0%	$75.00	$50.00	$62.50	1.462	49.37	51.00	0.65%
14	Otter Tail Corp.	58.7%	$1,187	$697	59.0%	$1,825	$1,077	9.1%	$55.00	$40.00	$47.50	1.943	39.56	44.00	2.15%
15	PNM Resources	43.6%	$3,888	$1,695	45.5%	$4,900	$2,230	5.6%	$40.00	$25.00	$32.50	1.204	79.65	79.65	0.00%
16	Pub Sv Enterprise Grp.	53.4%	$25,915	$13,839	50.5%	$34,600	$17,473	4.8%	$60.00	$45.00	$52.50	1.511	505.00	505.00	0.00%
17	Sempra Energy	43.5%	$29,135	$12,674	45.0%	$46,700	$21,015	10.6%	$160.00	$120.00	$140.00	1.972	251.36	296.00	3.32%

(a) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2022 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year compound rate of change.
(h) Average of High and Low expected market prices divided by 2022 BVPS.

CAPM - CURRENT BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Algonquin Pwr & Util	2.4%	11.1%	13.5%	3.0%	10.5%	n/a	n/a	$5,925.0	0.86%	n/a
2	Ameren Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$13,860.8	0.55%	10.4%
3	Avangrid, Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	0.40	7.2%	$15,577.9	0.55%	7.8%
4	Black Hills Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.90	12.5%	$2,998.1	1.36%	13.8%
5	CMS Energy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$12,254.9	0.55%	10.4%
6	DTE Energy Co.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$17,611.1	0.55%	10.4%
7	El Paso Electric Co.	2.4%	11.1%	13.5%	3.0%	10.5%	0.75	10.9%	$2,288.2	1.63%	12.5%
8	Emera Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	0.60	9.3%	$8,421.8	0.83%	10.1%
9	Entergy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$13,854.6	0.55%	10.4%
10	Exelon Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.70	10.4%	$38,654.8	-0.30%	10.1%
11	FirstEnergy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$15,900.1	0.55%	10.4%
12	IDACORP, Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	0.70	10.4%	$4,409.8	0.86%	11.2%
13	NorthWestern Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.65	9.8%	$2,765.6	1.36%	11.2%
14	Otter Tail Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.85	11.9%	$1,822.8	1.63%	13.6%
15	PNM Resources	2.4%	11.1%	13.5%	3.0%	10.5%	0.70	10.4%	$2,855.6	1.36%	11.7%
16	Pub Sv Enterprise Grp.	2.4%	11.1%	13.5%	3.0%	10.5%	0.70	10.4%	$25,613.3	-0.30%	10.1%
17	Sempra Energy	2.4%	11.1%	13.5%	3.0%	10.5%	0.80	11.4%	$26,600.6	-0.30%	11.1%
	Average							**10.2%**			**11.0%**
	Midpoint (g)							**9.8%**			**10.8%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved May 3, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 3, 2018), http://finance.yahoo.com (retrieved May 4, 2018), and www.zacks.com (retrieved May 3, 2018).

(c) Average yield on 30-year Treasury bonds for the six-months ending May 2018 based on data from the Federal Reserve at https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15.

(d) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.

(e) www.valueline.com (retrieved Jun. 14, 2018).

(f) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Algonquin Pwr & Util	2.4%	11.1%	13.5%	4.0%	9.5%	n/a	n/a	$5,925.0	0.86%	n/a
2	Ameren Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$13,860.8	0.55%	10.7%
3	Avangrid, Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	0.40	7.8%	$15,577.9	0.55%	8.4%
4	Black Hills Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.90	12.6%	$2,998.1	1.36%	13.9%
5	CMS Energy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$12,254.9	0.55%	10.7%
6	DTE Energy Co.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$17,611.1	0.55%	10.7%
7	El Paso Electric Co.	2.4%	11.1%	13.5%	4.0%	9.5%	0.75	11.1%	$2,288.2	1.63%	12.8%
8	Emera Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	0.60	9.7%	$8,421.8	0.83%	10.5%
9	Entergy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$13,854.6	0.55%	10.7%
10	Exelon Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.70	10.7%	$38,654.8	-0.30%	10.4%
11	FirstEnergy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$15,900.1	0.55%	10.7%
12	IDACORP, Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	0.70	10.7%	$4,409.8	0.86%	11.5%
13	NorthWestern Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.65	10.2%	$2,765.6	1.36%	11.5%
14	Otter Tail Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.85	12.1%	$1,822.8	1.63%	13.7%
15	PNM Resources	2.4%	11.1%	13.5%	4.0%	9.5%	0.70	10.7%	$2,855.6	1.36%	12.0%
16	Pub Sv Enterprise Grp.	2.4%	11.1%	13.5%	4.0%	9.5%	0.70	10.7%	$25,613.3	-0.30%	10.4%
17	Sempra Energy	2.4%	11.1%	13.5%	4.0%	9.5%	0.80	11.6%	$26,600.6	-0.30%	11.3%
	Average							**10.5%**			**11.2%**
	Midpoint (g)							**10.2%**			**11.2%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved May 3, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 3, 2018), http://finance.yahoo.com (retrieved May 4, 2018), and www.zacks.com (retrieved May 3, 2018).

(c) Average yield on 30-year Treasury bonds for 2019-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018); IHS Global Insight (Jun. 6, 2018); & Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018).

(d) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.

(e) www.valueline.com (retrieved Jun. 14, 2018).

(f) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(g) Average of low and high values.

EMPIRICAL CAPM - CURRENT BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP*[1]	Beta	Weight	*RP*[2]	RP	K_e	Cap	Adjustment	K_e
1	Algonquin Pwr & Util	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	n/a	75%	n/a	n/a	n/a	$5,925.0	0.86%	n/a
2	Ameren Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$13,860.8	0.55%	11.3%
3	Avangrid, Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.40	75%	3.2%	5.8%	8.8%	$15,577.9	0.55%	9.3%
4	Black Hills Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.90	75%	7.1%	9.7%	12.7%	$2,998.1	1.36%	14.1%
5	CMS Energy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$12,254.9	0.55%	11.3%
6	DTE Energy Co.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$17,611.1	0.55%	11.3%
7	El Paso Electric Co.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.75	75%	5.9%	8.5%	11.5%	$2,288.2	1.63%	13.2%
8	Emera Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.60	75%	4.7%	7.4%	10.4%	$8,421.8	0.83%	11.2%
9	Entergy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$13,854.6	0.55%	11.3%
10	Exelon Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.70	75%	5.5%	8.1%	11.1%	$38,654.8	-0.30%	10.8%
11	FirstEnergy Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$15,900.1	0.55%	11.3%
12	IDACORP, Inc.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.70	75%	5.5%	8.1%	11.1%	$4,409.8	0.86%	12.0%
13	NorthWestern Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.65	75%	5.1%	7.7%	10.7%	$2,765.6	1.36%	12.1%
14	Otter Tail Corp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.85	75%	6.7%	9.3%	12.3%	$1,822.8	1.63%	13.9%
15	PNM Resources	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.70	75%	5.5%	8.1%	11.1%	$2,855.6	1.36%	12.5%
16	Pub Sv Enterprise Grp.	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.70	75%	5.5%	8.1%	11.1%	$25,613.3	-0.30%	10.8%
17	Sempra Energy	2.4%	11.1%	13.5%	3.0%	10.5%	25%	2.6%	0.80	75%	6.3%	8.9%	11.9%	$26,600.6	-0.30%	11.6%
	Average												**11.0%**			**11.8%**
	Midpoint (h)												**10.7%**			**11.7%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved May 3, 2018).
(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 3, 2018), http://finance.yahoo.com (retrieved May 4, 2018), and www.zacks.com (retrieved May 3, 2018).
(c) Average yield on 30-year Treasury bonds for the six-months ending May 2018 based on data from the Federal Reserve at https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15.
(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.
(f) www.valueline.com (retrieved Jun. 14, 2018).
(g) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).
(h) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Algonquin Pwr & Util	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	n/a	75%	n/a	n/a	n/a	$ 5,925.0	0.86%	n/a
2	Ameren Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 13,860.8	0.55%	11.6%
3	Avangrid, Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.40	75%	2.9%	5.2%	9.2%	$ 15,577.9	0.55%	9.8%
4	Black Hills Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.90	75%	6.4%	8.8%	12.8%	$ 2,998.1	1.36%	14.1%
5	CMS Energy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 12,254.9	0.55%	11.6%
6	DTE Energy Co.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 17,611.1	0.55%	11.6%
7	El Paso Electric Co.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	11.7%	$ 2,288.2	1.63%	13.3%
8	Emera Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.60	75%	4.3%	6.7%	10.7%	$ 8,421.8	0.83%	11.5%
9	Entergy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 13,854.6	0.55%	11.6%
10	Exelon Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	11.4%	$ 38,654.8	-0.30%	11.1%
11	FirstEnergy Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 15,900.1	0.55%	11.6%
12	IDACORP, Inc.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	11.4%	$ 4,409.8	0.86%	12.2%
13	NorthWestern Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	11.0%	$ 2,765.6	1.36%	12.4%
14	Otter Tail Corp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.85	75%	6.1%	8.4%	12.4%	$ 1,822.8	1.63%	14.1%
15	PNM Resources	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	11.4%	$ 2,855.6	1.36%	12.7%
16	Pub Sv Enterprise Grp.	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	11.4%	$ 25,613.3	-0.30%	11.1%
17	Sempra Energy	2.4%	11.1%	13.5%	4.0%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	12.1%	$ 26,600.6	-0.30%	11.8%
	Average												**11.3%**			**12.0%**
	Midpoint (h)												**11.0%**			**12.0%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from Dividend paying components of S&P 500 index from zacks.com (retrieved May 3, 2018).

(b) Average of weighted average earnings growth rates from Value Line Investment Survey, IBES, and Zacks Investment Research for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 3, 2018), http://finance.yahoo.com (retrieved May 4, 2018), and www.zacks.com (retrieved May 3, 2018).

(c) Average yield on 30-year Treasury bonds for 2019-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 1, 2018); IHS Global Insight (Jun. 6, 2018); & Wolters Kluwer, Blue Chip Financial Forecasts, (Jun. 1, 2018).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.

(f) www.valueline.com (retrieved Jun. 14, 2018).

(g) Duff & Phelps Cost of Capital Navigator, 2018 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10-11, and CRSP Deciles Size Study).

(h) Average of low and high values.

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.28%
(b)	Average Utility Bond Yield	4.12%
	Change in Bond Yield	-4.16%
(c)	Risk Premium/Interest Rate Relationship	-0.4318
	Adjustment to Average Risk Premium	1.80%
(a)	Average Risk Premium over Study Period	3.71%
	Adjusted Risk Premium	**5.51%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield	4.43%
	Adjusted Equity Risk Premium	5.51%
	Risk Premium Cost of Equity	**9.94%**

(a) Exhibit 64, page 3.
(b) Average bond yield on all utility bonds and Baa subset for the six-months ending May 2018 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit 64, page 4.

ELECTRIC UTILITY RISK PREMIUM

PROJECTED BOND YIELD

	Current Equity Risk Premium	
(a)	Avg. Yield over Study Period	8.28%
(b)	Average Utility Bond Yield 2019-2023	5.93%
	Change in Bond Yield	-2.35%
(c)	Risk Premium/Interest Rate Relationship	-0.4318
	Adjustment to Average Risk Premium	1.01%
(a)	Average Risk Premium over Study Period	3.71%
	Adjusted Risk Premium	**4.72%**
	Implied Cost of Equity	
(b)	Baa Utility Bond Yield 2019-2023	6.24%
	Adjusted Equity Risk Premium	4.72%
	Risk Premium Cost of Equity	**10.96%**

(a) Exhibit 64, page 3.

(b) Yields on all utility bonds and Baa subset based on data from IHS Global Insight (Jun. 6, 2018); Energy Information Administration, Annual Energy Outlook 2018 (Feb. 6, 2018); & Moody's Investors Service at www.credittrends.com.

(c) Exhibit 64, page 4.

ELECTRIC UTILITY RISK PREMIUM

AUTHORIZED RETURNS

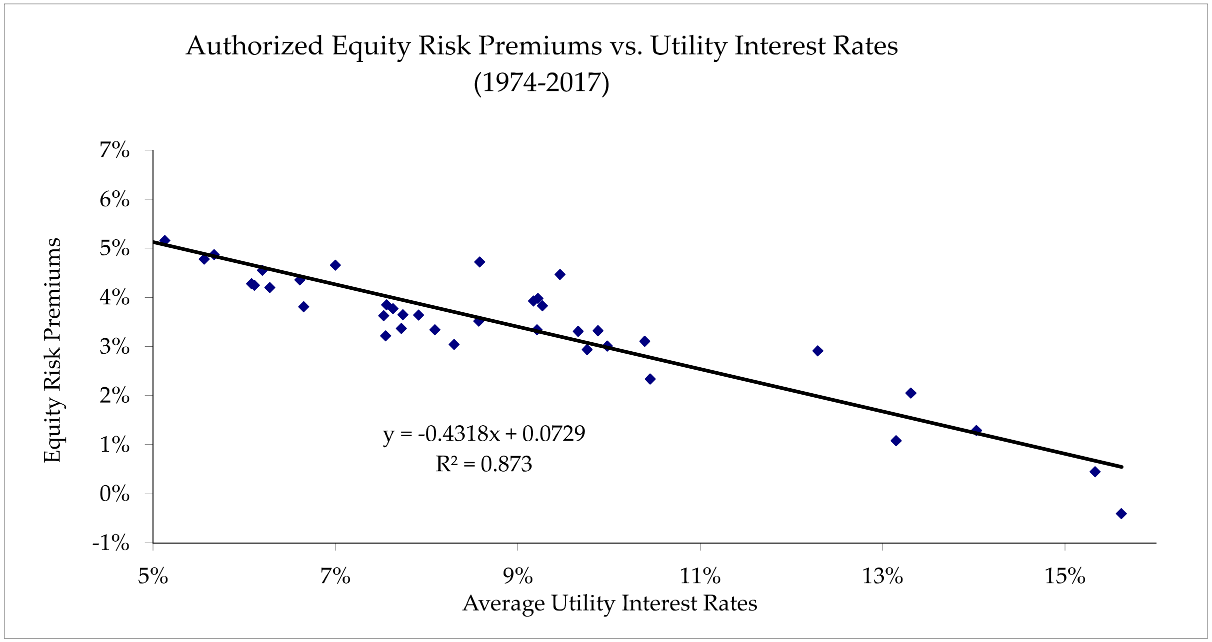
Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
2014	9.92%	4.41%	5.51%
2015	9.85%	4.37%	5.48%
2016	9.77%	4.11%	5.66%
2017	9.74%	4.07%	5.67%
Average	11.99%	8.28%	3.71%

(a) Major Rate Case Decisions, *Regulatory Focus* , Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

ELECTRIC UTILITY RISK PREMIUM

REGRESSION RESULTS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.934345084
R Square	0.873000736
Adjusted R Square	0.869976944
Standard Error	0.004907631
Observations	44

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006953548	0.006953548	288.7105784	1.97526E-20
Residual	42	0.001011563	2.40848E-05		
Total	43	0.007965112			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072885799	0.002231138	32.66753843	1.73387E-31	0.068383179	0.077388419	0.068383179	0.077388419
X Variable 1	-0.431830074	0.025414498	-16.99148547	1.97526E-20	-0.483118608	-0.380541541	-0.483118608	-0.380541541

EXPECTED EARNINGS APPROACH

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Algonquin Pwr & Util	n/a	n/a	n/a
2	Ameren Corp.	10.5%	1.0264	10.8%
3	Avangrid, Inc.	6.0%	1.0090	6.1%
4	Black Hills Corp.	10.0%	1.0359	10.4%
5	CMS Energy Corp.	13.5%	1.0391	14.0%
6	DTE Energy Co.	11.0%	1.0345	11.4%
7	El Paso Electric Co.	9.0%	1.0187	9.2%
8	Emera Inc.	12.5%	1.0192	12.7%
9	Entergy Corp.	12.0%	1.0306	12.4%
10	Exelon Corp.	9.5%	1.0266	9.8%
11	FirstEnergy Corp.	15.5%	1.0931	16.9%
12	IDACORP, Inc.	9.0%	1.0172	9.2%
13	NorthWestern Corp.	9.5%	1.0195	9.7%
14	Otter Tail Corp.	10.5%	1.0435	11.0%
15	PNM Resources	9.5%	1.0274	9.8%
16	Pub Sv Enterprise Grp.	11.0%	1.0233	11.3%
17	Sempra Energy	11.0%	1.0505	11.6%
	Average (d)			**10.9%**
	Midpoint (d,e)			**11.6%**

(a) The Value Line Investment Survey (Apr. 27, May 18, & Jun. 15, 2018); Mar. 23, 2018 for Emera.
(b) Adjustment to convert year-end return to an average rate of return from Exhibit 61.
(c) (a) x (b).
(d) Excludes highlighted values.
(e) Average of low and high values.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	AT&T Inc.	Telecommunications	$ 32.56	$ 2.01	6.2%
2	Church & Dwight	Household Products	$ 47.57	$ 0.87	1.8%
3	Coca-Cola	Beverage	$ 42.79	$ 1.56	3.6%
4	Federal Realty	REIT	$ 118.36	$ 4.04	3.4%
5	General Mills	Food Processing	$ 42.86	$ 1.96	4.6%
6	Kellogg	Food Processing	$ 62.95	$ 2.22	3.5%
7	Kimberly-Clark	Household Products	$ 103.40	$ 4.00	3.9%
8	Lilly (Eli)	Drug Industry	$ 83.17	$ 2.25	2.7%
9	Procter & Gamble	Household Products	$ 74.26	$ 2.87	3.9%
10	Smucker (J.M.)	Food Processing	$ 108.68	$ 3.18	2.9%
11	Sysco Corp.	Wholesale Food	$ 64.60	$ 1.44	2.2%
12	Walmart Inc.	Retail Store	$ 84.11	$ 2.08	2.5%
	Average				**3.4%**

(a) Average of closing prices for 30 trading days ended Jun. 15, 2018.

(b) The Value Line Investment Survey, Summary & Index (Jun. 15, 2018).

DCF MODEL - NON-UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)	(f)
		Earnings Growth					
	Company	V Line	IBES	Zacks	Bloomberg	S&P Capital IQ	FactSet
1	AT&T Inc.	5.50%	11.71%	3.42%	5.00%	7.01%	5.50%
2	Church & Dwight	9.00%	10.56%	9.99%	10.31%	10.18%	10.50%
3	Coca-Cola	5.00%	7.60%	8.19%	8.49%	7.58%	7.50%
4	Federal Realty	n/a	5.00%	6.00%	4.20%	6.00%	4.10%
5	General Mills	4.00%	6.23%	7.50%	7.33%	8.00%	6.10%
6	Kellogg	7.00%	6.82%	7.34%	8.07%	8.28%	7.30%
7	Kimberly-Clark	9.50%	6.75%	6.95%	14.24%	6.32%	13.50%
8	Lilly (Eli)	11.00%	11.80%	11.46%	10.57%	10.99%	11.00%
9	Procter & Gamble	9.00%	7.24%	7.22%	7.45%	7.38%	7.20%
10	Smucker (J.M.)	7.50%	6.60%	7.50%	6.70%	21.20%	10.10%
11	Sysco Corp.	14.00%	14.27%	10.44%	11.85%	13.85%	11.80%
12	Walmart Inc.	5.50%	6.47%	6.73%	6.21%	7.31%	9.70%

(a) The Value Line Investment Survey (Mar. 23, Apr. 6, Apr. 20, Apr. 27, & Jun. 15, 2018).
(b) www.finance.yahoo.com (retrieved Jun. 18, 2018).
(c) www.zacks.com (retrieved Jun. 18, 2018).
(d) Bloomberg L.P. (retrieved Jun. 5, 2018).
(e) SNL Financial (retrieved Jun. 5, 2018).
(f) FactSet (retrieved Jun. 5, 2018).