CASE NO. 2020-00349 AND CASE NO. 2020-00350
LEXINGTON-FAYETTE URBAN COUNTY GOVERNMENT
AND LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT

Exhibit Bunch 8

OLSON, BZDOK & HOWARD

June 26, 2020

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-20697

Dear Ms. Felice:

The following is attached for paperless electronic filing:

REVISED PUBLIC Direct Testimony and Exhibits MAU-14 and MAU-15 of Richard Bunch on behalf of Michigan Municipal Association for Utility Issues

Proof of Service

NOTE: The Revised Confidential Version will be served upon those with a signed Nondisclosure Agreement on file

Sincerely,

Tracy Jane Andrews
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xc: Parties to Case No. U-20697

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697 ALJ Dennis Mack

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REVISED - PUBLIC

DIRECT TESTIMONY OF RICHARD BUNCH

ON BEHALF OF

MICHIGAN MUNICIPAL ASSOCIATION FOR UTILITY ISSUES

June 26, 2020
~~June 24, 2020~~

TABLE OF CONTENTS

REVISED PUBLIC DIRECT TESTIMONY OF RICHARD BUNCH
U-20697

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Richard Bunch. I am Executive Director of Michigan Municipal Association for Utility Issues (MI-MAUI). I am also a senior consultant at 5 Lakes Energy, LLC. My business address is 115 W. Allegan St., Suite 710, Lansing, MI 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Municipal Association for Utility Issues (MI-MAUI).

Q. What is MI-MAUI?

A. MI-MAUI is a non-profit membership association formed by Michigan municipal governments to provide them with a collective voice and technical support in their relationships with regulated utilities and in Michigan Public Service Commission proceedings.

Q. Please summarize your educational background.

A. I hold a Master of Business Administration degree with Environmental Management Certificate from University of Washington Business School, and a bachelor's degree in political science from Yale University. My resumé is attached as **Exhibit MAU-1**.

Q. Please summarize your professional development coursework in the field of electric utility regulation.

A. In June of 2019 I attended EUCI's Outdoor Street Lighting Conference: Best practices in streetlight design, strategy, deployment, and LEDs in Atlanta. In July of 2019 I attended EUCI's Electric Cost-of-Service - Essential Concepts for a Changing Industry Course in Chicago.

Q. Please summarize your experience in the field of electric utility regulation.

A. I have worked for more than five years in positions related to clean energy, primarily on behalf of local governments. A significant portion of that work has included analysis of MPSC rate and other cases and supporting local government participation in rate cases and other MPSC proceedings. From 2015-2017 I organized and led the Municipal Street Lighting Coalition, a group of 24 municipalities served by DTE Energy, which intervened in Cases U-17767 and U-18014 and participated in the MPSC-ordered street lighting collaborative. I organized and supported intervention of several municipalities receiving street lighting services from Consumers Energy in case U-20134. I have submitted comments in several other dockets on behalf of MI-MAUI and have participated in various MI Power Grid working groups and the Electric Distribution Planning working group. My energy-related work experience is summarized in my resumé, provided as **Exhibit MAU-1**.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. Yes. I provided expert witness testimony on production cost allocation in case number U-20561, DTE Electric rate case.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MI-MAUI regarding street lighting rates and tariffs. A summary of my concerns and recommendations follows on pages 4-8.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- MAU-1: resumé of Richard Bunch

- MAU-2: City of Ferndale LED conversion budget from DTE Energy
- MAU-3: City of Grand Rapids LED conversion proposal
- MAU-4: City of Detroit LED conversion bid tabulation sheet
- MAU-5C: CONFIDENTIAL Consumers Energy LED conversion costs, discovery response U20697-MAUI-CE-174
- MAU-6: discovery response U20697-MAUI-CE-1144, tracking of comparative costs of reactive vs planned LED conversions
- MAU-7: Leotek HID-LED crossover recommendations
- MAU-8: MyLightingGuide.com HID-LED crossover recommendations
- MAU-9: Summary of Results: Round 7 of Product Testing (U.S. DOE Solid-State Lighting CALiPER program)
- MAU-10C: CONFIDENTIAL LED spec sheet from Consumers' primary LED luminaire provider
- MAU-11: DesignLights Consortium Solid State Lighting (SSL) Technical Requirements Version 5.1
- MAU-12C: CONFIDENTIAL Consumers Energy streetlight technical specs tabulation
- MAU-13: witness Aponte discovery response U20697-MAUI-CE-724_ATT_1, Consumers Energy unmetered lighting Distribution Plant In Service
- MAU-14: unified unmetered lighting rate
- MAU-15: Lightsmart bid tabulation for various street lighting maintenance and construction tasks
- MAU-16: Consumers Energy streetlight outage statistics
- MAU-17: DTE Energy streetlight outage statistics

- MAU-18: City of Flint streetlight removal cost

II. STREET LIGHTING RATES AND TARIFFS

Q. Why are MI-MAUI member municipalities concerned about street lighting rates and tariffs?

A. Street lighting is commonly the biggest energy expense for municipal governments that do not operate water treatment facilities. Comprising just over 1% of Consumers' rate base, street lighting has a small impact on Consumers' bottom line but can comprise as much as one-third of a municipality's energy costs.

To cut costs, municipalities are eager to quickly transition to light-emitting diode (LED) street lighting, which is 65% more energy-efficient and has a longer service life than incumbent high-intensity discharge (HID) lighting technologies. Customers also prefer LED lighting because it offers superior illumination and higher reliability than HID lighting. A growing number of municipalities also have climate, sustainability or related policy goals that require significant energy efficiency improvements, and LED street lighting is one of the quickest and most cost-effective ways to realize these improvements while also improving quality of service.

Q. What topics pertaining to street lighting will you address in your testimony?

A. I will primarily address issues related to the conversion of Consumers Energy's streetlight fleet from HID to LED technology. More specifically, I will argue that:

- The Company's LED conversions have significantly higher costs than peer utilities, municipal utilities and third-party lighting providers;
- The Company's proposed LED fixture fee is too high and denies customers who have previously paid full cost for LED conversions fair recovery of their investments as

originally projected in conversion proposals provided by the Company. The proposed fee also requires customers to begin paying for second-generation LED fixtures long before the customer-paid first-generation fixtures can be expected to require replacement;

- The Company's LED conversions result in higher illumination than the replaced fixtures, driving up costs, wasting energy and potentially creating illumination hazards and nuisances;
- The Company's plan to convert center-suspension streetlights to pole-mounted LED installations is too expensive and needlessly increases illumination levels;
- The Company's burnout conversion program and proposed tariff structure create inequities among customers, who have little effective influence over the timing of costs that affect their rates;
- The Company's calculation and allocation of distribution plant-in-service rate base and O&M costs for the GUL and GU-LED unmetered rates contain methodological and data errors;
- The Company's streetlight reliability and outage restoration performance fail to meet company standards and customer expectations, and the company's plans for improving performance are unresponsive and insufficient;
- The Company's streetlight removal fee policy charges customers too much for removal of unwanted fixtures.

Q. What are your primary recommendations for changes to Consumers Energy's proposed street lighting rates and tariffs?

A. My key recommendations include:

- The Commission should order the Company to bring its LED conversion costs in line with reasonable costs as achieved by many peer and alternative providers.

- The Commission should reduce the amounts the Company has added to rate base from excessive LED conversion expenditures;
- The Commission should order the Company to adopt practices and incur LED conversion costs justified by IESNA roadway lighting standards, to ensure customers are not paying excessive capital and operating costs and to comply with recognized standards for roadway safety and minimization of light pollution and light trespass.
- The Commission should order the Company to study cost differences between reactive and planned group conversions of LED fixtures, and to revise cost allocations and customer contribution requirements accordingly.
- The Commission should order the Company to correct its rate base calculations for Streetlighting Distribution Plant In Service to reflect planned retirement of 55,000 GUL streetlights from 2019-2021.
- The Commission should order the Company to adopt a single, unified tariff for all unmetered lighting that charges customers the same amounts for equivalent HID and LED illumination.
- If the Commission does not order the Company to implement a single, unified tariff for unmetered lighting, then it should order the Company to revise how it allocates costs between the two unmetered rates: GUL and GU-XL:
    - The allocation methodology for street lighting O&M costs should reflect that LED fixtures last longer and are more reliable than HID equipment, and therefore drive less O&M cost. The current allocation is based mostly on cost of luminaires, and because LEDs are more expensive this leads to relatively higher per-fixture

allocation of O&M to LED fixtures than to HID fixtures.

- LED conversion costs directly allocated to the GU-XL (later, GU-LED) rate should be adjusted to reflect reasonable LED conversion costs.
- Distribution plant in service should not be allocated between the two unmetered rates (GUL and GU-XL) according to luminaire Plant In Service: costs for poles, suspensions, wiring, transformers and other lighting assets are not caused by cost of the fixture they serve, but are rather related to fixture count and/or electricity use.

- The Commission should order the Company to credit customers who paid for LED conversions, prior to the Company's switch to reactive conversions requiring no customer contribution, the full amount of proposed capital cost recovery for LED conversions until 2032.
- The Commission should order the Company to revise its plans and cost projections for center-suspension LED conversions to bring costs in line with industry norms and to conform with roadway lighting standards.
- The Commission should order the Company to issue automatic bill credits based on each customer's lights found to be out of compliance with performance standards in a statistically valid periodic field assessment, and for those credits to remain in effect until a new field assessment updates that finding.
- The Commission should order the Company to provide every street lighting customer with an annual reliability and bill credits report.
- The Commission should order the Company to collaborate with customers and other stakeholders to identify management practices, available technology and delegations of

responsibility to cost-effectively reduce the management burden placed on customers to identify, report and track streetlight outage and reliability problems.

- The Commission should order the Company not to require customer contributions for removal of streetlights, and to allow customers to purchase streetlight assets from the Company when they cancel streetlighting contracts.

I also make a number of recommendations for Company business and management practices intended to demonstrate feasibility and fairness of the Commission orders I recommend, and to improve cost-effectiveness and reliability of the Company's streetlighting services.

III. THE COMPANY'S LED CONVERSION COSTS ARE TOO HIGH

Q. Why is LED conversion cost important if the company is no longer requiring customers to pay a contribution in aid of construction?

A. Because customers will still pay the conversion costs but will pay them over time as part of the tariff rather than as an up-front contribution in aid of construction. The company proposes to add conversion costs to rate base, which will drive up the annual tariff cost for LED fixtures and sharply reduce potential savings for customers.

Q. How much do the Company's LED conversion projects cost?

A. Between $850 and $1078 per fixture, on average.

Company witness Miller, in discovery response U20697-MAUI-CE-179 (6)(f)(1), states "The most common customer street light conversion, 100W HPS cobra-head to a 54 W LED cobra-head, costs about $700." However, the particular conversion cited by Miller also involves the lowest-wattage, and therefore cheapest, LED luminaire that the Company currently installs. Average costs, including higher-wattage luminaries, are somewhat higher.

- I calculate the average total cost of LED conversions through 12/31/2018 to have been $1,073. The Company states that it had invested $13,258,000 as of 12/31/2018[1], comprising 15,320 LED luminaires[2] The Company also states that customer contributions toward conversion costs as of 12/31/2018 totaled $3,180,615.[3] The sum of customer contributions and Company capital costs through 2018 was therefore $16,438,615 and the average conversion cost was therefore $1,073.
- I estimate the average LED conversion cost in 2019 was $859. In 2019, "the Company identified 4,308 mercury vapor and roughly 16,060 burnouts converted to LEDs..."[4] The Company budgeted $17,500,000 in additions to LED (GU-XL) streetlighting assets that year.[5]

Q: How do Consumers' conversion costs compare to those of peer utilities and competitive market lighting installers?

A: Consumers' average LED conversion costs are about 4x what other providers charge lighting customers for comparable conversions.

- My **Exhibit MAU-2** is a LED streetlight conversion proposal provided to the City of Ferndale, MI by DTE Energy in May of 2019, and retrieved from the City

[1] Discovery response U20697-MAUI-CE-724-Aponte-ATT1, row 6.
[2] Witness Miller, WP+HWM-24, sum of fixtures converted before 2018 policy change (call G41) and after policy change through 12/31/2018 (cell D10).
[3] Discovery response U-20697-MAUI-CE-1138(b), witness Aponte.
[4] Discovery response U20697-MAUI-CE-735(b), witness Miller.
[5] Witness Aponte, discovery response U20697-MAUI-CE-724-Aponte-ATT-1, sum of rows 26 to 28.

Council's public website.[6] The cost figures are not itemized, but the lowest-wattage, and therefore cheapest, conversions shown on the proposal are comparable to the conversion example that company witness Miller provides. The average gross cost per fixture for conversion is about $239, but after energy optimization rebate the city's out-of-pocket net cost was $357,018 for 1,744 fixtures, an average cost of $204 per fixture. This unit cost is dramatically lower than costs allocated by Consumers Energy for comparable conversions.

- My **Exhibit MAU-3** is a budgetary estimate prepared for the City of Grand Rapids for LED streetlight conversions, provided in MPSC case U-20134 by witness Douglas Jester on behalf of the Cities of Grand Rapids and Flint. Mr. Jester's direct testimony in that case reads:

"The City of Grand Rapids has obtained cost information from vendors and prepared a budgetary estimate for conversion of its City-owned streetlights to LED. I have summarized that information as Exhibit FGR-7. The City's estimate is $415.65 per light for the conversions, including an approximately $90.39 cost to purchase software and an advanced communications and control module in each light, which Consumers Energy does not include in its lights. Thus, Consumers Energy's $650 cost to convert a light to LED appears to be about twice the cost to the City of Grand Rapids from an independent vendor, when the $90.39 module is

[6] https://docs.google.com/gview?url=https%3A%2F%2Fgranicus_production_attachments.s3.amazonaws.com%2Fferndalemi%2Fc2ea044188fa3d749010f2906a1805b90.pdf&embedded=true&urp=gmail_link

factored in."[7]

Note also that Grand Rapids estimated an average fixture cost of $225.26 per light. If we substitute Consumers' actual fixture costs, which for the most common LED fixtures are at least $100 lower than Grand Rapids' estimate, then Grand Rapids' average cost per equivalent fixture would be very similar to the costs assessed by DTE.

- My **Exhibit MAU-4** is a bid tabulation sheet provided by the Detroit Public Lighting Authority, for a 2019 project replacing 20,154 LED streetlights of a model prone to premature failure. This project is similar in scope of work to removing an HID luminaire and replacing it with an LED luminaire, per the Company's current process. However, material costs were not included in the Detroit bids because the failing lights were under warranty. Bids were to cover removal of defective luminaire, installation of new luminaire, storage and traffic control costs. Bids ranged from a low of $65/luminaire to a high of $195. If $100-$200 were added for luminaire cost, these bids would have very similar average cost to the Ferndale and Grand Rapids projects.

Both the Grand Rapids and Detroit bids came from third-party, competitive market providers. They do not separately specify other direct costs and loadings, which are presumably embedded in the specified direct costs. In contrast, Consumers' other direct

[7] MPSC case U-20134, Corrected Direct Testimony of Douglas Jester, p.18.

costs and loadings are roughly [[[redacted]]] the direct labor and materials costs.

In sum, these data show that other regulated utilities, and municipal utilities offering comparable streetlighting LED conversion services, incur dramatically lower costs than Consumers reports.

Q: Why are the Company's LED conversion costs higher than those of peer utilities and competitive market providers?

A: The Company's unloaded material and labor costs, ranging from [[[redacted]]] for the most common LED conversions, appear to be similar to those of peer organizations.[8] The biggest cost differences appear to be the Company's other direct costs and loadings. These include:

[redacted]

- [redacted]]].

Q: Why do you argue that the Company's other direct and indirect costs for LED conversions are excessive?

A: Because these costs clearly exceed industry norms. Consumers should adopt conversion methods and cost allocations that bring total costs in line with those of competitive market

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[8] All cost data in this response refers to U20697 **Exhibit MAU-5C**, confidential discovery response U20697-MAUI-CE-174(a).

providers. If the Company cannot accomplish such a cost reduction for any reason, it should either hire third-party contractors to perform conversions, or allow customers to contract directly with third-party providers to perform conversions.

Q: Why are the Company's LED conversion costs higher than the examples you benchmark against?

A: The primary driver of the Company's high conversion costs, in comparison to the other examples I have provided, appears to be its reactive method for conversions. Reactive conversions occur when an HID outage is reported. If the fixture is a mercury vapor or high-pressure sodium luminaire in a cobra head installation, the Company attempts no repairs or lamp replacements, but rather switches out the old luminaire for an LED. Reactive conversions require a crew to gather luminaires and other materials specific to each outage, and to incur significant down time and travel costs traveling to, and setting up at, random outage locations. Specifically:

- The Company's Storeroom/Material costs are allocated at about [[[redacted]]] indirect charge. High storage costs result from reactive conversions because the Company needs to keep materials on hand for any contingency. Planned, group conversions can order materials when and as needed, limiting or even eliminating the need for keeping an inventory of backup and spare parts.
- The Company adds [[[redacted]]] in indirect fleet costs to every LED conversion, as

[9] U20697 **Exhibit MAU-5C**, confidential discovery response U20697-MAUI-CE-174(a).

well as [redacted]]] in indirect labor (162% of the charge for direct labor for time on job-site).[10] These figures suggest that more time is spent preparing for and driving to and from job sites than in performing the hands-on conversion work. High mileage, and indirect labor costs in transit to jobs, result from the Company converting luminaires as they randomly fail in different locations, rather than converting all fixtures in a neighborhood at once, regardless of condition. In short, the Company's approach to conversions fails to realize obvious potential efficiencies from a process that is substantially the same from pole to pole.

In contrast, the providers I benchmarked above all use planned, group conversions as their predominant approach. This approach converts all luminaires in an area at the same time, greatly reducing travel and setup time between fixtures. This approach can also reduce or even eliminate storage costs because all materials can be delivered just in time, and potentially direct to the work location. In short, planned conversions can sharply reduce indirect labor, storeroom and fleet costs, which, as I noted above, add [[[redacted]]] on top of Consumers' direct material and labor costs.

Q: Have the Company's planned, group LED conversion projects been lower-cost than its reactive conversions?

A: We don't know, because the Company has not differentiated between these two approaches in its cost tracking and allocation.

The Company has converted at least 4,750 fixtures to LED as part of planned, group

[10] U20697 **Exhibit MAU-5C**, confidential discovery response U20697-MAUI-CE-174(a).

conversions,[11] but has recognized no cost differential between these two approaches: "There are no differences in determining and allocating the costs and loadings of a reactive conversion versus a planned group conversion."[12] However, "the Company has not studied and compared actual costs of reactive and planned conversion projects."[13]

My recommendation that the Company adopt planned, group conversion methods is therefore based on the straightforward assertion that group conversions offer obvious productivity gains, and the evidence that other providers who do planned, group conversions report much lower costs.

Q. What causes the Company to allocate higher loadings to LED conversions than the providers you benchmarked?

A: The Company's loading costs are calculated using various formulas based on unloaded labor and materials and other direct costs. Therefore, loadings would be reduced significantly if the various direct costs were reduced, per my testimony above.

However, as I noted above, the Company's loadings equal [[[redacted]]] of unloaded labor and materials for the most common LED conversions. Thus, even if other direct costs were wholly eliminated, I estimate that the Company's total LED conversions costs including loadings would range from about $400 to $600 for the most common conversions. This range is still roughly double what other providers charge, and yet these

[11] Witness Blumenstock's response to discovery question U20697-CE-MAUI-174.
[12] Witness Blumenstock in response to discovery question U20697-MAU-CE-176.
[13] My U20697 **Exhibit MAU-6**, from witness Blumenstock's response to discovery question U20697-MAUI-CE-1144.

other providers also must cover all the same costs that the Company includes in loadings.

When loadings result in costs imposed on customers significantly in excess of competitive market alternatives, it is incumbent on the Company and the Commission to find a way to reduce the cost burden. If the Company cannot reduce loadings significantly when performing conversions using Company personnel, it should either contract with third-party providers with lower cost structures or allow customers to contract directly with third-party providers.

Q: Does the Company contract with third-party lighting conversion contractors? Why or why not?

A: No. Witness Blumenstock states, "The Company does not currently have any third-party contracts to perform LED conversions, nor are there any such contracts under current consideration." He goes on to explain, "The Company is limited by a union contract provision under which only 15% of all low voltage distribution work, which includes streetlighting, may be performed by third-party contractors, with the remaining 85% required to be performed by Company employees." [14]

Contractual limitations notwithstanding, the Company had ample capacity left within the 15% outside contracting cap in 2018 to hire out for all LED conversions. In 2018, Company employees performed 2,457,170 hours of all low-voltage distribution (LVD) work (which includes streetlight circuits), which would allow for 433,618 hours of contractor work. Contractors actually performed 340,381 hours of LVD work in 2018, leaving 93,237 hours

[14] Witness Blumenstock in discovery response U20697-MAUI-CE-178 (b) and (c).

of unused potential contractor work.[15] The Company performed roughly 10,000 LED conversions in 2018. Crews working on planned conversion projects typically convert 3 to 4 fixtures per hour, or very roughly one conversion per labor hour. Thus, 10,000 planned conversions would require about 10,000 contract labor hours, a small fraction of the unused allowable contractor LVD hours in 2018.

Q Why should the Company allow customers to contract directly for LED lighting conversions?

A: The primary reason is to allow customers to reduce conversion costs by using competitive market providers. The Company could specify qualifications for contractors to work on its street lighting circuits, and technical standards for luminaires.

There are at least three other reasons why customers would benefit from choosing their own lighting conversion contractors. First, they would have more control over lighting specifications, including HID-to-LED wattage crossovers, energy efficiency of the new luminaires, color temperature and color rendering index, expected service life and backlight/uplight/glare ratings. The second reason is that customers could decide for themselves when they want to incur the expense of converting particular lights. The third reason is that municipalities would save a significant amount of money beyond lower up-front conversion costs, because they have a lower cost of capital compared to the Company.

Q: Please summarize your recommendations concerning the cost of the Company's LED

[15] Witness Blumenstock in discovery response U20697-MAUI-CE-731.

conversions.

A: I recommend that the Commission disallow excessive costs for past LED conversions to be added to rate base.

I recommend that the Commission cap the Company's LED conversion costs for cobra head fixtures at an average no greater than $300 per fixture including loadings.

In support of these orders, I recommend that the Company:

- Adopt planned, group LED conversions as its primary way of deploying LED luminaires;
- Hire third-party contractors to perform most LED conversions, or allow customers to hire conversion contractors themselves.

IV. THE COMPANY'S PROPOSED LED CONVERSION FEE IS EXCESSIVE AND IS UNFAIR TO CUSTOMERS WHO PAID CONVERSION COSTS UP FRONT

Q: How is the Company proposing to recover LED conversion costs, if not through customer contributions?

A: The company calculates that it needs to charge customers $40 per LED fixture per year to recover its investment in the LEDs. There are two problems with this proposal. First, the $40 charge is based on excessive costs, as I argued above. Second, inadequate relief is proposed for customers who already paid conversion costs up-front and should not be asked to pay a second time.

Q: How might the Commission allow the Company to recover reasonable LED conversion costs?

A: Consistent with my testimony above, the Commission should disallow addition of excessive conversion costs to rate base and should ensure that all customer contributions to conversions are credited against reasonable costs.

If the Company's conversion costs were on a par with the peer examples I provided above, their annual cost recovery would be about $13 rather than $40. This difference would represent very significant savings for customers, who often have thousands of streetlights.

Q. How is the Company's proposed $40 annual fee on LED fixtures unfair to customers who paid contributions in aid of construction to cover conversion costs?

A. The Company proposes to issue a $40 annual credit to customers who paid conversion costs up-front for the first four years after the fee is added to the LED tariff. The proposed credit is too short in duration and denies energy-efficiency first-movers a significant chunk of the projected financial benefits that led them to make the LED investment.

Q: Why is the credit too short in duration?

A: The four-year credit, added to the varying lengths of time that customer-paid LEDs have already been installed, add up to much less than the expected service life of an LED fixture. It is not fair to require a customer to begin paying toward cost recovery of a replacement asset before the replacement can reasonably be expected to enter service.

Most durable products last much longer than their initial warranty period and LEDs are no exception. The warranty period for LEDs Consumers has installed is ten years.[16] However, the fixtures the Company has installed have a manufacturer-projected service life of at least 60,000 hours, or about 15 years.[17] Newer versions of the luminaire models the Company

[16] Witness Blumenstock, in response to discovery question U20697-MAUI-CE-179(d).
[17] Witness Blumenstock, U20697-MAUI-CE-733-Blumenstock_ATT_1.

installs actually have much longer useful lives. The Company's most common LED model is a 54-watt luminaire manufactured by [[[redacted]]], and current product literature shows this model is expected to reach 100,000+ hours (almost 24 years) with L70 lumen maintenance.[18] The L70 rating is the manufacturer-predicted number of operating hours until an LED luminaire dims to 70 percent of its initial light output, at which point it should be replaced to maintain design lighting levels. L70 is important because LED fixtures tend not to burn out suddenly so as to trigger an outage report; they tend to dim very slowly and unnoticeably over time. Detecting LED "failure" therefore requires periodic photometric assessment by trained staff, rather than casual observation and reporting by members of the public.

The Company first converted a significant number of luminaires to LED in 2016, meaning that there should be no meaningful level of LED fixture failures until at least 2031. It would not be fair to ask customers to start paying for replacement LEDs in 2025 if the original LEDs can reasonably be expected to continue functioning until at least 2031. If the Company can make a reasonable showing that a significant number of first-generation LEDs start failing earlier than their L70 ratings predict, then the duration of the credit can be revisited in a later rate case.

Q: How does the proposed LED credit deny customers expected returns on investment?

Customers should be permitted to benefit from cost savings the company projected for them when they decided to invest in LEDs. For the common 100w HPS-54w LED conversion described above, customers realize a payback in about ten years and realize net savings only after that – disregarding the greatly reduced present value of savings ten years

[18] U20697 **Exhibit MAU-10**

from now.[19] Prematurely imposing an additional $40 annual cost on these customers will effectively ensure that these "first-mover" municipalities never recover their investments on some, if not most, of their LEDs. Allowing these customers to benefit from their full anticipated savings over time may also encourage them to confidently invest in future energy efficiency projects.

Q: What do you recommend the Commission order with respect to credits for customers who paid up-front fees for LED conversions?

A: The simplest way to ensure that customers are not forced to pay twice for first-mover conversions is to credit them back all LED cost recovery charges until their first-generation LED fixtures are replaced. The Company has apparently not tracked individual LED fixtures, unfortunately, making it difficult to know in the future whether any particular failed LED fixture was installed at customer or company cost.[20] I suggest two possible solutions:

1. Credit customers for however many LED conversions they paid for until a specified future date, after which it is assumed they will all have failed and been replaced at company expense. That date should be set by adding the expected lifetime of the fixtures - the manufacturer's L70 rating – to the average installation date of customer-paid LEDs installed before the Company began reactively converting failed fixtures without charging a customer contribution. Although the Company's

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[19] According to Company witness Miller in response to discovery question U2069-MAUI-CE-179 (6f), the common 100w HPS to 54w LED now saves customers about $70 per year and costs the customer about $700 up front, creating an undiscounted payback period of ten years. Annual savings would be reduced to $55.80 under the Company's proposed rates, lengthening simple payback to almost 12 years.

[20] "For planned work, the work order includes a drawing of the proposed work and captures as-built information as entered by field personnel. For reactive work, the order captures as-built information and a general location, but does not capture specific customer information (emphasis added). SAP orders are retained indefinitely. Given the volume of work orders in the Company's SAP system, it is not feasible to individually identify all such records." Witness Blumenstock, discovery response U20697-MAUI-CE-732.

preferred LED model now has expected lifetime over 24 years, an unknown number of earlier-generation LEDs with expected lifetime of 15 years have been installed. The first significant number of LEDs were installed in 2016. Therefore, I recommend that credits be extended until at least 2032.

2. Alternatively, mandate that the credit should be extended until the Company provides evidence in a rate case that more than half of its LEDs installed before April 2018 (when the Company implemented its no-cost burnout conversion program) have failed off-warranty and been replaced.

V. THE COMPANY IS INSTALLING LED LUMINAIRES THAT ARE TOO BRIGHT AND TOO EXPENSIVE

Q. Why is it important for the Company to observe technical lighting standards?

A: Technical lighting standards help ensure that streetlights provide the right amount of illumination in the right places, enhancing roadway safety and minimizing wasted capital expense, energy and light, light pollution and light trespass. Installing fixtures that are too bright not only compromises safety and creates nuisance illumination, but also wastes money on excessive capital and operating expenditures.

Q: How do the Company's conversion practices create a risk of excessive roadway illumination?

A. The company is using LED conversion crossover equivalencies that may create significantly higher roadway effective illumination levels than the existing HID lights. For example, the Company usually replaces 100-watt HPS fixtures with 54-watt LED luminaires; ~~yet it also often replaces 150-watt HPS fixtures with the same 54-watt LED.~~

As I will discuss below, the 54-watt LED provides more effective illumination on target than the 100-watt HPS, resulting in over-illumination, excessive capital and operating cost and wasted energy.

Q: How much energy should a properly specified LED luminaire use compared to the HID fixture it replaces?

A: Newer LED luminaires typically use about 35% of the energy of the HID luminaires they replace. The spec sheet for one of the largest LED streetlight manufacturers, Leotek, recommends replacing a 100w HPS luminaire (which consumes 117 watts in total) with a 39-watt LED to provide visibility comparable to the HID being replaced.[21] A 54-watt LED is recommended only "when required to meet or exceed current luminance values or when highly conservative light loss factors are being applied." Other manufacturers recommend more aggressive crossover wattage reductions than Leotek.[22]

The 39-watt Leotek LED produces 4850 lumens, considerably fewer than the 8500 lumens produced by Consumers' 100w HPS luminaires. However, lumen output alone is not a rigorous standard for comparing HID to LED fixtures. LEDs waste a much lower percentage of lumens to internal fixture losses and lumens going off-target, and LEDs create higher-quality light that requires fewer lumens to support necessary visual tasks. Thus, LEDs can provide the same level of effective lighting while generating significantly fewer lumens than HIDs.

Q: How much more efficient are LEDs, compared to HPS lights, at ensuring lumens they produce illuminate the target roadway and sidewalk?

[21] U20697 **Exhibit MAU-7**
[22] See also U20697 **Exhibit MAU-8** for an example of manufacturer-recommended HID-LED crossovers with somewhat higher energy savings than Leotek's.

A: LEDs are substantially more efficient and accurate than HPS and mercury vapor fixtures. To illustrate, I reference the common 100w HPS to 54w LED conversion cited by the Company in discovery responses. The Company's tariffs state that the 100w HPS creates 8,5000 lumens, but it is important to consider how many of those lumens end up in the target area of the roadway. HPS fixtures have a much higher proportion of lumens produced that are wasted or go off target, compared to LEDs.

Existing HPS fixtures typically lose 35% to 37% of their rated output to internal fixture losses. Thus, the U.S. Department of Energy's CALiPER 7 study (**Exhibit MAU-9**) reported the actual lumens exiting a typical "benchmark" 100w HPS fixture is 6,540 lumens, although it produced 9,500 lumens in total.[23] LED luminaires suffer from virtually no internal fixture losses.

In addition, lumens that do exit the fixture may go off target. Manufacturers provide BUG (Backlight, Uplight, Glare) ratings for their fixtures. Higher numbers equate to higher lumens going off-target. The Company's 100w HPS fixture has a BUG rating of B3 U3 G2.[24], indicating that this fixture loses significant lumens to backlight (e.g., toward houses rather than toward street) and uplight (light pollution) and creates a moderate amount of discomfort glare for roadway users. In comparison, the Company's standard replacement for the 100w HPS, a 54w LED, rates B1 U0 G1, indicating very low loss to lumens going off-target.

Summing internal fixture losses and lumens going off target, of the 8,500 lumens generated by the Company's standard 100w HPS luminaire, the effective lumens aimed at the

[23] "Summary of Results: Round 7 of Product Testing," DOE Solid State Lighting CALiPER Program, table 2, p.8. Attached as **Exhibit MAU-9**.
[24] U20697-MAUI-CE-733-Blumenstock_ATT_1, "Sheet 1".

roadway are approximately 50% of the nominal output. However, the comparative analysis does not end there because the on-target lumens produced by an HPS fixture provide much less visual support than those produced by LEDs.

Q: How is LED light more effective at supporting visual tasks than HPS light?

A: LEDs have a much higher Color Rendering Index (CRI) than HPS and mercury vapor fixtures. This means they can provide the same level of visual support as HPS and mercury vapor fixtures while producing significantly fewer lumens on target.

CRI measures the ability of a light source to accurately reproduce the colors of the objects it illuminates, with 100 being the highest. High CRI of LEDs is important for safety because the human eye is more sensitive in the environment lit up by high CRI lighting. Roadway users can have lower reaction time to identify dangerous situations. The Company's 54-watt LED luminaire has a CRI of 75.[25] In comparison, DOE CALiPER testing of a 100-watt (nominal) HPS fixture measured its CRI as 21.[26] It is difficult to describe how to compare these two ratings, but qualitatively they indicate that an HPS fixture must generate many more lumens on target to achieve the same level of visual support as an LED fixture.

In sum, LEDs can produce the same effectiveness of roadway lighting using far less energy. First, LEDs are much more effective at turning watts into lumens. Second, LEDs lose far fewer lumens within the fixture. Third, LEDs are much better at directing light leaving the fixture to its intended target. Fourth, LEDs produce light that is much more effective at supporting necessary visual tasks in the target roadway.

[25] U20697 **Exhibit MAUI-10C** CONFIDENTIAL
[26] U20697 **Exhibit MAUI-9** CALiPER, P4, Table 1A.

Q: How is the greater effective illumination of LEDs relevant to the Company's choices of LEDs to replace HID fixtures?

A: In short, the differences in energy savings and up-front cost between Consumers' HID-LED crossover and typical manufacturer-recommended crossovers are striking and consequential. A 100w HPS actually consumes 117w when its ballast is taken into consideration. Thus, Consumers' 100w-HPS-to-54w-LED conversion saves 63 watts, whereas a common manufacturer-recommended crossover to a 39-watt LED saves 87 watts. Therefore, by following the manufacturer's recommendation, the company could increase energy efficiency from LED conversions about 38% compared to its current crossover. In addition, a 54w LED is significantly more expensive to buy than the manufacturer-recommended 30w LED, and thus the Company is incurring excessive cost that drives up rates. For example, the Company's direct materials cost difference between its 54-watt and 72-watt LED luminaires is [[[redacted]]][27]; presumably stepping down from a 54-watt to a 39-watt LED would reap a similar cost differential.

In the absence of a field lighting study, there is no benefit to routinely increasing roadway illumination levels. Energy and money are wasted, there are no demonstrable safety benefits and excessive lighting may cause unsafe glare and light trespass. Over-illumination may also fuel public complaints that new LED lighting is too bright.

Q: Are LEDs inherently better than HID lights at maximizing lumens on target and minimizing light trespass?

[27] Exhibit U-20697-MAU-5C

A: More important than any inherent differences is the flexibility of LED configurations that can ensure that the right amount of light ends up where it's wanted and nowhere else. But that happens only when proper design and specifications are employed.

The Illuminating Engineering Society of North America (IESNA) has defined five standard light distribution patterns. The Company's cobra head-mounted luminaires have Type II distribution[28], which creates a flattened oval pattern about 1.5 times as wide as the fixture height off-ground. This pattern is best suited for two-lane side streets.

For wider streets such as arterials, Type III distribution is best, creating a "fatter" oval of light that reaches farther across the street from the pole. The Company did not list any Type III cobra-head fixtures in response to my discovery request about lighting distribution patterns of its fixtures. It is notable, for example, that the Company's standard 85w and 171w cobra-head LED luminaires both have Type II distribution patterns. Luminaires this bright are used on wider roadways, where more light is needed and the "fatter" Type III distribution pattern can reach the far side of the road and sidewalk. Using Type II luminaires on wider roadways risks under-illumination of lanes of traffic and sidewalk on the opposite side of the street from the pole. Conversely, using the Company's standard 85w and 171w LED luminaires on a residential side street would achieve the desired illumination pattern but would deliver far too much light for that setting.

For the circular ends of cul-de-sacs, a Type V circular distribution is best. Customers have complained to me that Company LEDs mounted above cul-de-sac circles have created light trespass nuisances for houses at the head of the circle. This observation suggests that the

[28] [28] U20697 **Exhibit MAU-12C** CONFIDENTIAL, taken from witness Blumenstock discovery response U20697-MAUI-CE-733-Blumenstock_ATT_1, "Sheet 1". All following references to Company luminaire specs come from this Exhibit.

Company is installing Type II luminaires in these locations, which not only fail to illuminate the circle uniformly, but the extremes of the oval distribution pattern also create unwanted illumination of adjacent driveways, yards and buildings. The Company did not list any Type V fixtures in response to my discovery request about lighting distribution patterns of its fixtures.

While it is generally possible to retrofit luminaires with shields to prevent unwanted light distribution, doing so either wastes those lumens or redirects them to on-target areas that already receive sufficient illumination. Shielding also requires additional labor to assess the problem, purchase or fabricate shielding and send a crew out to install it. It is much preferable to install luminaires manufactured with the desired distribution patterns for each site to begin with.

I therefore recommend that the Company specify lighting distribution patterns tailored to each LED retrofit, rather than using a default distribution pattern(s).

Q: Are the Company's choices of LED luminaires considered state of the art?

A: Despite its LEDs being superior in energy efficiency, lighting effectiveness and service lives compared to the Company's HPS and mercury vapor luminaires, the Company could, and should, be buying fixtures with higher energy efficiency and visual ratings with longer useful lifetimes. LEDs are a costly, long-lived product and a technology that is improving rapidly. It makes no sense to save a few dollars by buying a product that was state-of-the-art even two years ago.

The gold standard for LED product performance is established by the DesignLights Consortium's Qualified Products List (QPL) Premium listing.[29] The DesignLights

[29] U20697 **Exhibit MAU-11** DLC QPL specs.

Consortium is a non-profit organization whose mission is to achieve energy optimization by enabling interconnected solutions with a focus on quality for people and the environment. The DLC promotes high-quality, energy-efficient lighting products in collaboration with utilities and energy efficiency program members, manufacturers, lighting designers, and federal, state, and local entities. Through these partnerships, the DLC establishes product quality specifications, facilitates thought leadership, and provides information, education, tools and technical expertise.

For example, QPL Premium listing now requires outdoor luminaires to achieve luminous efficacy greater than 120 lumens/watt. The currently produced version of the 54w LED luminaire used by the Company produces about 100 lm/w – a difference of 20%, which adds up to a lot of energy and cost over the projected 100,000-hour lifetime of the fixture. QPL criteria also include specifications for quality of light, controllability, L70 lumen maintenance, testing and reporting. I recommend that the Company adopt a policy of buying QPL Premium-listed equipment wherever practicable.

Q: Why should the Commission take an interest in the Company's decisions about luminaire specifications and lighting design?

A: Street lighting customers buy not only electricity from the Company, but also must use the equipment the Company selects for them with little or no input. Commission oversight of the Company's technical product and lighting standards is the only effective way to protect customers' interests, since it is very difficult for them to use alternative providers of street lighting services.

Q: How should the Commission rule with respect to the Company's observance of technical lighting standards?

A: The Commission should focus not on the standards themselves but on the impact of the Company's decisions on customer costs and quality and reliability of service. The Commission should limit the Company's ability to recover costs if it buys outdated equipment that falls short of current standards for energy efficiency, illumination quality and service life.

Q: Please sum up your recommendations regarding the Company's conversion and lighting standards.

A: I recommend that the Company revisit its HID-LED crossover criteria and design process to ensure that it achieves recommended levels of roadway lighting after conversions and optimizes capital and operating costs of LEDs by installing the right LED for each site.

I also recommend that the Company stock LEDs with more light distribution patterns, to ensure optimum lighting of target areas with minimal light trespass.

I recommend the Company buy lighting products that meet DesignLights Consortium QPL Premium criteria wherever practicable. If the Company does not wish to agree by third-party technical product and lighting standards, the Commission should limit cost recovery to protect customers' interests.

VI. THE COMPANY'S PLAN TO CONVERT CENTER-SUSPENSION STREETLIGHTS TO POLE-MOUNTED COBRAHEAD LEDS IS TOO EXPENSIVE

Q: Do you support the Company's proposal to replace center-suspension lights with pole-mounted cobrahead LEDs?

A: Yes, with reservations. Center-suspension lights are difficult and potentially dangerous to service because they hang over the roadway and are less compatible with LED technology than pole mounts. I also support the Company's proposal not to require customer contributions toward conversion costs, because these conversions are not being performed at the customer's request.

Q. What are your reservations about the Company's plans for center-suspension conversions?

A. The Company's cost estimates are based on a questionable assumption that each center-suspension fixture will need to be replaced by two pole-mounted LED luminaires. Replacing each center-suspension HID fixture with two new LED luminaires is not only unnecessarily expensive, but also runs the risk of over-illuminating the roadway.

The Company appears to be inappropriately including removal costs of center-suspension fixtures in its LED-conversion costing scenario.

Finally, like LED cobra-head conversion costs, the Company's projected unit costs for fixture and pole installation are well above market rates.

Q: What are the Company's plans for replacing center-suspension streetlights with pole-mounted LEDs?

A: As stated in discovery response 20697-MAUI-CE-177 (4)(c), "In many cases, the appropriate design will be two new pole mounted fixtures to replace the center suspension." The Company's cost scenario for these conversions also assumes two new poles and 54-watt LEDs replacing one 100-watt HPS fixture

Q: Why do you argue that the Company should install one new pole-mounted cobra-head LED luminaire to replace most, if not all, center suspension HID lights?

A: First, because one LED luminaire can easily provide as much effective illumination as the existing center-suspension mounting. The Company's cost scenario for center-suspension conversions assumes an existing 100-watt HPS fixture. As noted above, the Company usually replaces 100-watt HPS fixtures with single 54-watt LED luminaires; and even this conversion in many, if not most, settings will increase roadway illumination.

Second, a roadside-pole-mounted LED luminaire with the appropriate distribution pattern and mounted at the right location, height, luminaire orientation and suspension arm length need not be over the middle of the roadway to provide the same, or even superior, illumination to the center-mount HPS fixture it replaces. In fact, the Company's center-suspension lights have BUG ratings of B3 U3 G2, similar to the Company's HPS cobra head lights but with an inferior backlight rating, and much worse than the Company's standard LED cobra head luminaires. In rural settings where center-suspension lights are common, light pollution from uplight and light trespass from backlight can be even more annoying to nearby property owners than in urban areas with more ambient light.

While there will be differences from site to site that require design modification, the standard costing scenario should call for one new pole and LED luminaire. In some cases, an existing pole supporting the center-suspension cable can be repurposed as a cobrahead fixture mount; in other cases two new poles and luminaires may be needed.

Q. Why is it a bad idea to increase illumination when converting center-suspension lights to LEDs?

A. On high-speed rural roads, where center-suspension lights are common, rather than helping with visibility excessively bright lights can create dangerous glare conditions For example, on a rainy night, glare from poorly placed or too-bright LED luminaires could impair visibility for drivers stopping at crossing roads, who need to clearly see through-traffic before they pull out.

In the absence of a site-specific lighting design study, the Company should normally match illumination levels provided by the existing suspension-mounted HIDs using a single, lower-wattage pole-mounted cobra-head LED. This scenario provides another example of why the Company should employ the full range of IESNA lighting distribution patterns, as the standard Type II pattern the Company now uses is unlikely to illuminate the full width of a rural highway from a roadside pole.

Q. Why do you state that the Company's projected center-suspension conversion costs are too high?

A. Three reasons:

- First, as I noted above, the Company's default LED design should call for a single pole with cobrahead LED fixture on a long suspension arm, rather than two LEDs each on new poles; and should re-use existing poles wherever feasible. That change alone should cut projected costs per site nearly in half.
- Second, just as with its cost allocations for cobrahead HID-to-LED conversions, the Company's unit costs exceed market rates.
- Third, the Company's cost estimate appears to include removal costs, which have already been recovered through depreciation.

Q: What evidence do you have that the Company's unit costs exceed market rates?

A: I provided evidence earlier that the Company's indirect labor, other direct costs and loadings for general LED light conversions are very high compared to benchmarked peers. The same excessive allocations appear in the Company's cost estimate for center-suspension lights.

As further evidence, I provide **Exhibit MAU-15**, a bid tabulation sheet for various streetlight O&M and installation tasks for Rhode Island municipalities, provided by LightSmart Consulting, which manages public streetlighting systems in several states.

In the exhibit, row E1-38 reads, “Remove broken non-utility wooden pole (assume approximately one to two feet of the old pole is left above ground as from a knockdown) and install new 35foot wooden pole with standard six-foot bracket and supplied LED fixture. Dispose of old pole.” Bid prices received ranged between $881 and $3,800, with the high end of that range being roughly equal to Consumer’s projected cost per pole. This scenario likely involves more work than many of Consumers’ center-suspension conversions, because the replacement fixture can often be mounted to one of the existing poles so a new pole is not required and if the company choses they can recover the unneeded pole for future use or sale. The Rhode Island costing also includes removal costs, which are not properly included in a costing scenario for center-suspension to LED pole-mounted lights. In short, while the scopes of work are not quite apple-to-apple, levelizing adjustments all reduce the comparative cost of the Rhode Island bids, which even before adjustments are cheaper than Consumers’ projected costs.

Q: Why do you argue that removal costs may be included in conversion project costs, but should not be?

A: In response to discovery question U20697-MAUI-CE-177(h)(ii), witness Blumenstock wrote, “Customers will have the option of removing the center suspension rather than converting it, because removal of the center suspension is already part of the work required for conversion.”

Additionally, witness Blumenstock states, "The [[[redacted]]] amount was used for planning purposes and included project loadings and $1,000 for traffic control. Many center suspensions are located on highways and at major intersections, so the additional amount for traffic control was added for planning purposes."[30]

These responses suggest that removal of the old center-suspension fixtures is included in the conversion cost estimate, because the Company's proposal to phase out these installations is premised on the safety issues and resulting traffic control costs that result from removing a fixture that is hanging over the middle of the roadway.

Under Federal Energy Regulatory Commission (FERC) accounting regulations, removal costs are part of net salvage value that is included in depreciation base for an asset and is collected from the customer as part of its tariff payments over the lifetime of the asset. Rate-basing any additional net salvage costs, or collecting them as an up-front customer contribution, as part of LED conversion would ultimately charge customers twice for net salvage costs. Rather, all removal costs should be charged to depreciation reserve, since that is where the net salvage value portion of customer's tariffs payments are credited.

Q: Please summarize your recommendations for the Company's proposed center-suspension streetlight LED conversion program.

A: The Commission should approve the Company's proposal to replace center-suspension streetlights with pole-mounted LEDs at no out-of-pocket cost to the customer. The Commission should not approve the Company's projected costs or lighting design for these LED conversions.

[30] Witness Blumenstock, CONFIDENTIAL discovery response U20697-MAUI-CE-741.

The Company should plan to replace most, if not all, center-suspension lights with a single pole-mounted cobrahead LED fixture and maintain current levels of illumination unless a site-specific lighting design study supports changes.

The Company should exclude net salvage value of center suspension lights, cables and poles from LED conversion project costs.

The Company should commit to incurring competitive-market costs for conversion projects or solicit bids from third-party contractors to do the work.

VII. THE COMPANY'S POLICY OF CONVERTING HID LIGHTS TO LED ON FAILURE CREATES TARIFF INEQUITIES AMONG CUSTOMERS WHOSE DECISIONS DO NOT CAUSE THE CONVERSION

Q. How does the company's tariff structure, combined with its policy of converting most streetlights to LED reactively, create inequity among customers?

A. A bedrock principle of rate design is that customers should pay only costs that they cause. It cannot be argued that customers cause an LED conversion that the Company decides to incur rather than to repair an existing HID light, nor do they cause the consequent reduction in tariff to the LED rate. Likewise, it cannot be argued that customers whose HID fixtures last longer than other customers' fixtures deserve to go on paying higher GUL rates as a result of their "good luck."

Q: How can the company assure tariff equity between customers with LED lights and those with HID lights?

A: Customers should pay the same rate for an HID fixture as they pay for its LED equivalent.

The straightforward way to achieve this equity is to create a single, unified tariff for all unmetered lights regardless of technology; that is, to merge the GUL and proposed GU-LED rates, under which customers would pay the same amount for equivalent lighting services regardless of what kind of fixture they have installed at any given time. For example, customers would pay the same for a 54-watt LED as for a 100-watt HPS (disregarding for the moment my recommendation that the Company revise that particular crossover). Similar LED crossover equivalencies would be established for all other existing HID fixture wattages and technologies. Costs for LEDs and HIDs would be pooled together to determine the new revenue-neutral tariff for each tier of the rate table. As a higher and higher proportion of each rate tier turned over to LED, reaping increasing energy efficiency and O&M cost reduction benefits, the rate would progress downward for all customers with fixtures in that tier.

This tariff structure means that customers can be financially indifferent as to when each of their fixtures are converted to LED: everybody shares equally in the financial benefits of the ongoing conversion, regardless of when the Company converts their lights. In turn, the Company can more easily adopt a group conversion process and work through conversion of its fleet in an orderly and efficient fashion, without concern for spreading the financial benefits of LEDs equally among all customers every year.

Put simply, this rate structure would offer lighting as a service. Customers pay the same amount for comparable levels and quality of lighting, regardless of what kind of lighting equipment is installed. As more and more HID lights are converted to LEDs, the ~~unit~~ per-fixture energy charge will decline, saving all customers money at the same rate. This is appropriate because customers are no longer choosing when lights are converted and are not contributing up-front to the cost.

Q: How would the Company go about designing a unified unmetered lighting tariff?

A: The process is conceptually simple:

1. Find predicted 2021 fixture counts by technology (LED, HPS, MV, Fluorescent, Metal Halide, Incandescent) and watts.[31] Total projected number of unbilled fixtures in GUL and GU-LED in 2021 is projected to be 202,231.
2. Assign each HID fixture to a LED equivalent wattage tier, using the tiers in the Company's proposed GU-LED rate table. In my table below, I used the manufacturer crossover chart in my Exhibit MAUI-n (RJB-7) and other publicly available manufacturer or vendor sources to find LED crossover equivalents. For example, I found that 100-watt HPS fixtures are equivalent to 39-watt LEDs and placed them in the 35-44-watt LED tier. Though sourced, my LED equivalency assignments for each HID fixture are meant to be illustrative, not prescriptive;
3. Calculate total energy usage in each tier, assuming that every fixture in that tier (including HIDs) has already been converted to LED and consumes energy in the middle of the LED tier. For example, the 100-watt HPS fixtures that I put in the 35-44-watt LED tier are now modeled as using 40 watts. Sum up modeled energy use in each LED tier to find total modeled energy use for GUL and GU-LED combined.
4. Identify total proposed 2021 test year revenue for the GUL and GU-LED rates. [32]
5. Calculate total 2021 delivery charge revenue for the GUL and GU-LED rates by

[31] I found these data in witness Miller's WP-HWM-5_Lighting.
[32] I used "Tariff Revenue excluding Unbilled" for GUL and GU-LED from witness Aponte's ex0220-Aponte-1-3 and WP-1-81, "Workpaper_Dist+Prod" worksheet.

multiplying total unmetered fixture count from step 1 times $5 (the Company's propose 2021 test year GUL delivery fee).

6. Find target energy charge revenue by subtracting total delivery charge revenue found in step 5 from total test-year revenue found in step 4.
7. Find projected electric sales (in kwh) for 2021 for GUL and GU-LED, summed.[33]
8. Find target energy charge/kwh for each rate tier by dividing the total energy charge revenue found in step 6 by the total kwh sales found in step 7.
9. Find target energy charge/fixture/month for each rate tier by multiplying energy charge/kwh from step 8 times 350 hours per month times kilowatts (using middle of LED tier).
10. Add energy charge/fixture/month to delivery charge/fixture/month to derive total

[33] I used ex0220-Aponte-1-3 and WP-1-81, "Workpapers_Dist+Prod" worksheet.

charge/fixture/month.

My results are in Table 1, below, with full detail in my **Exhibit MAU-14~~12C~~**.

Table 1 (see also **Exhibit MAU-14**)

Combined unmetered lighting rate							
LED range (watts)	HPS watts	MH watts	Incand watts	Fluor watts	Energy charge	Delivery charge	Monthly cost
15-24			202		$ 1.83	$ 5.00	$ 6.83
25-34			405		$ 2.75	$ 5.00	$ 7.75
35-44	117				$ 3.67	$ 5.00	$ 8.67
45-54		0	690		$ 4.58	$ 5.00	$ 9.58
55-64		0			$ 5.50	$ 5.00	$ 10.50
65-74	171				$ 6.42	$ 5.00	$ 11.42
75-84		0			$ 7.34	$ 5.00	$ 12.34
85-94					$ 8.25	$ 5.00	$ 13.25
95-104					$ 9.17	$ 5.00	$ 14.17
105-114	247			470	$ 10.09	$ 5.00	$ 15.09
115-124	318	9912			$ 11.00	$ 5.00	$ 16.00
125-134					$ 11.92	$ 5.00	$ 16.92
135-144					$ 12.84	$ 5.00	$ 17.84
145-154					$ 13.75	$ 5.00	$ 18.75
155-164					$ 14.67	$ 5.00	$ 19.67
165-174					$ 15.59	$ 5.00	$ 20.59
175-184					$ 16.50	$ 5.00	$ 21.50
185-194					$ 17.42	$ 5.00	$ 22.42
195-204					$ 18.34	$ 5.00	$ 23.34
205-214	480				$ 19.25	$ 5.00	$ 24.25

Q: How should unmetered tariffs for customer-owned fixtures be designed?

A: Customer who own their fixtures should not receive a rate that blends HID and LED costs because lighting is not a service for them – they choose what lighting equipment to install, and therefore how much electricity they will use, and they pay for any changes to their light deployment. The Company should implement energy-based rates for customer-owned unmetered lights as proposed. However, to make the tariffs more reader-friendly, the Company should consider displaying rates for all customer-owned HID and LED fixtures in one table. Going forward, then, the Company would have two unmetered rate tables: one for company-owned fixtures with blended HID/LED rates; and the second for customer-owned unmetered fixtures, with energy-based rates.

Q: Please summarize your recommendations regarding the Company's unmetered lighting rate design.

A: The Commission should order the Company to implement a single, unified unmetered lighting rate for Company-owned fixtures, that charges customers the same amount for equivalent lighting regardless of fixture technology type.

The Commission should order the Company to implement a single, unified tariff for customer-owned lights based on electricity usage.

VIII. THE COMPANY'S UNMETERED LIGHTING RATE BASE AND COST ALLOCATIONS INCORPORATE COST-CAUSATION AND DATA ERRORS

Q: How is the Company calculating and allocating Distribution Plant In Service incorrectly for the GUL and GU-XL unmetered rates?

A: In discovery response U20697-MAUI-CE-724, witness Aponte states, "The Company starting point was the 2018 ending balance for FERC Account 373, per accounting records, which shows the historic costs by type of luminaire. Then, it applied the ratio of the HID and LED **luminaire costs** (emphasis added) to the balances of the brackets, poles, and transformers to split these costs between GUL and GU-XL. Finally, it added the investments in LED being sponsored in the case by Company witness Richard T.

Blumenstock to the GU-XL amount to arrive at the Streetlighting Equipment Plant in Service balance for the test year."

The first problem with this allocation is that bracket, pole and transformer costs are not related to luminaire costs. The fact that an LED luminaire is more expensive than an HPS luminaire does not mean it needs a more-expensive pole, bracket or suspension arm, and because it uses less electricity it may actually cause *less* wiring and transformer cost. A more equitable way to allocate non-luminaire street lighting asset costs among the lighting rates would be by fixture count, although both wiring and transformer costs arguably should be allocated according to measures of electricity usage

The second problem with the Company's allocation of Streetlighting Equipment Plant in Service is that it incorporates changes in LED luminaire count but does not account for offsetting changes in HID luminaire count. From 2019 through 2021, the Company projects that it will convert 55,000 fixtures from HID to LED, or about 42% of the total HID fixtures it owned as of 12/31/2018. Yet, witness Aponte's allocation of Plant In Service to the GUL rate shows 2018 Historic Balance of $90,820,000, and the exact same 2021 Test Year Balance, suggesting no change in luminaire count under GUL.[34]

GUL Plant In Service has two primary components: HID luminaires and Poles/transformers/brackets.

- Value of HID luminaires Plant In Service shows in witness Aponte's worksheet as $55,687,000 as of 12/31/2018. With 42% of the HID luminaires being retired from service through 2021, we should expect that figure to fall by about the same amount, or $23,000,000.

[34] U20697 **Exhibit MAU-13**, discovery response U20698-MAUI-CE-724-Aponte-ATT-1, rows 25 and 35.

- Value of poles/transformers/brackets in GUL as of 12/31/2018 was $35,133,000. As 42% of HID luminaires are converted to LED through 2021, we should expect the same amount of poles/transformers/brackets to migrate from the GUL Plant In Service over to GU-LED.

Proper allocation of pole/brackets/transformers is of minor concern if the Company merges the two unmetered rates going forward. Plant In Service for GULs needs to be corrected either way, however, because the error appears to be overstating the lighting rate base in 2021 by $23,000,000.

The Company's proposed rates are not accurate if 2021 Plant In Service is overstated by $23,000,000. The Company should correct these errors and recalculate rates.

Q: How is the company allocating excessive O&M costs to LEDs?

A: Distribution Operation Expense and Distribution Maintenance Expense for streetlights are allocated using Allocator 311.[35] This allocator is calculated according to the proportion of Total Distribution Streetlighting Equipment directly allocated to each unmetered lighting rate under Plant In Service/Distribution & General.[36] The largest component of Distribution Streetlighting Equipment is luminaire cost. This method of allocation is incorrect because LEDs cost less to operate and maintain than HIDs. Charging LEDs higher O&M based on their higher capital cost is inconsistent with cost causation principles. In fact, a key motivation for paying more for LEDs than for HID luminaires is to reap lower operating (energy and O&M) costs over time and allocating O&M according to luminaire cost defeats this objective.

Q: Why do you state that LEDs have lower O&M costs than HID luminaires?

[35] Company witness Aponte exhibit A-16 (JCA-1). Schedule F-1, lines 13 and 36.
[36] Company witness Aponte workpaper ex0220-Aponte-1-3 and WP-1-81, "Dist" worksheet, row 620.

A: I make this as a general statement with limited application to the Company's current operations.

The average life expectancy of an HID lamp is six years with a fixture life of 15-18 years based on the projected ballast life of 56,000-65,000 hours (when the ballast fails it is more cost effective to replace the fixture than the cost of labor to change out the ballast).[37] This results in an average service frequency of roughly 18-20% of the HID fixtures per year. LED lights have a projected life of 20 years and come with a ten-year warranty. As a result, their average repair rate has proven to be less than 3% which requires fewer work orders, fewer truck rolls, less warehousing, and lower overall Administrative and General (A & G) costs. (Replacement of an LED at 20+ years is not a maintenance cost.)

Furthermore, the Company's LED fleet is very new. The great majority of LED-related costs should be capital costs incurred when the new fixtures are installed. New LED fixtures should incur even lower O&M costs when new than later in their service lives.

The difficulty with applying this general reasoning in the current situation is that the Company has stopped performing O&M on HID cobra-head luminaires. When something goes wrong, rather than replacing lamps or making repairs, the Company simply swaps out the fixture for a new LED. The conversion is recorded as a capital cost rather than O&M. Thus, both HID and LED luminaires should incur very low O&M costs over the next several years, and O&M costs would seem to have little, if anything, to do with the luminaires themselves or how much they cost.

However, luminaire problems are not the only streetlighting O&M work that needs doing. Problems with streetlight circuit wiring, transformers, poles, brackets and suspensions also

[37] The Company did not provide L70 ratings for its HID cobrahead luminaires in discovery and they are not available on the manufacturer's website.

occur. Intuitively, maintenance issues with these assets have nothing to do with the kind of luminaire they support or how much that luminaire cost.

Therefore, I recommend that O&M costs be allocated according to the count of fixtures served under each lighting rate.

Q: Why not allocate O&M costs according to actual O&M historical records?

A: This approach would be more accurate, but the Company does not currently track O&M costs by asset type. In response to discovery questions U20697-MAUI-CE-740, witness Blumenstock states, "The Company does not track operation and maintenance costs separately for LED and HID fixtures." While O&M data are presumably available to reconstruct a detailed history of expense by type of asset, such an exercise likely cannot be undertaken within the time frame of this rate case.

In general, the Company's O&M recordkeeping needs to be detailed enough to support informed management of its fleet. Especially as the Company invests more and more in relatively expensive LED fixtures, it needs to know how well various manufacturers and models perform over time, and to make data-supported maintenance plans for these expensive assets.

I therefore recommend that the Company revise its O&M recordkeeping to track repairs by asset type, and to rely on these records to propose an empirically grounded method for allocating O&M in its next rate case.

Q: Please summarize your recommendations regarding calculation and allocation of Distribution Plant In Service for unmetered lighting rates

A: The Commission should order the Company to:

- Correct total Distribution Plant In Service to reflect HID luminaire retirements projected through 2021;
- Change its method for allocating streetlighting assets other than luminaires according to luminaire type. Poles, brackets and suspension arms should be allocated by fixture count and wiring and transformers should be allocated according to electricity use.

If the Commission chooses not to order the Company to adopt a single unified unmetered lighting tariff per my preceding recommendation, then the Commission should order the Company to revise its method for allocating streetlighting O&M costs, using fixture count rather than luminaire Plant In Service values. In that event, the Commission should also order the Company to correct Poles/transformers/brackets Plant In Service to reflect the ongoing migration of fixture from the GUL to the GU-LED rate.

IX. THE COMPANY SHOULD IMPROVE ITS STREETLIGHT OUTAGE IDENTIFICATION AND RESTORATION PERFORMANCE

Q. Is streetlight reliability important to customers?

A. Yes. Reliability is the most frequently mentioned concern among municipal officials. To be more precise, community members complain to municipal officials about non-functioning lights much more than any other street lighting topic. Other lighting issues, such as cost and lighting quality, also concern municipal officials, but they get far fewer complaints about those other topics compared to outage complaints. The imperative to keep the lights on has led some municipalities to incur significant expenditures to assign staff to periodic nighttime streetlight patrols, other staff to documenting and reporting identified problems, and finally doing a follow-up drive-by to ensure a problem has been resolved. Cash-strapped and short-handed, municipalities don’t want to go to these lengths, but feel they must respond to community expectations.

Consequently, municipal officials want to see fewer outages, quicker resolution of outages, and less burden on municipal staff to identify or respond to problems, report and track resolution. Unfortunately, the Company's outage frequency and duration have not been improving in recent years, and steps the Company proposes in this case are not directly or promptly responsive to those key issues.

Q: Please summarize the Company's recent streetlight reliability performance.

A: Reliability has worsened since 2017 by several measures:[38]

- Average outage duration has risen from 6 days in 2017 to 8 days in both 2018 and 2019.
- Average total outage time per fixture rose from 10.33 hours to 12.17 hours in 2019.
- The number of outages exceeding five days in length rose from 7,204 to 7,748.

Because many outages are likely not reported promptly, and because of an error in the way average outage time per fixture is calculated (see below), the figures above are likely significantly understated.

In a more positive light, the total number of reported outages declined from 21,234 in 2017 to 19,727 in 2019. This slight decline appears to be proportional to the gradual increase in LED fixture counts: LEDs are generally more reliable than HID fixtures, and as a rule new luminaires are less likely to malfunction than older ones. I am not able to support this inference with empirical data because the Company did not supply outage data organized

[38] U20697 **Exhibit MAU-16**, from witness Blumenstock discovery response U20697-MAUI-CE-181.

by fixture type.

Q: What caused changes in streetlight reliability performance from 2017 through 2019?

A: We don’t know – and that’s a problem.

The reason we don’t know what caused changes in reliability performance is that the Company is not keeping track. When asked to break down the total number of outages in 2019 into primary causes, witness Blumenstock replied, “The Company does not track outage causes at the level of detail requested.”[39] While the Company may be able to improve its response time to outages (see below), it cannot reduce the number of outages through prevention until it begins to track their causes.

Q: Could changes in streetlight reliability be attributable to normal year-to-year variations?

A: Probably not. Witness Blumenstock writes, “(T)he Company believes the data indicates small year-over-year variations in outage durations, with variations due to location, type of work required, and other factors.”[40]

Indeed, we can expect natural year-to-year random variations in performance, but statistics and available evidence cast doubt on this explanation for the scale of variations reported by the Company. In a population of approximately 170,000 unmetered lights, even small year-to-year variations are statistically significant. Yet, these variations are not “small”: average outage duration rose 25% from 2017 to 2018 and remained steady in 2019; (claimed) average outage time per fixture rose by 7% from 2017 to 2019. Distribution system power outages are not included in streetlight outage statistics; weather events can still impact dedicated streetlight circuits, but in general citing weather as a variable cause

[39] Witness Blumenstock in response to discovery question U20697-MAUI-CE-737(b)
[40] Witness Blumenstock in response to discovery question U20697-MAUI-CE-737(a).

of outages has more limited explanatory power for streetlights than for the overall electric distribution system.

In addition, we know that the vast majority of outages reported in 2019 required straightforward LED conversions of burned-out HID fixtures. In 2019, there were 19,727 reported outages.[41] We also know that 16,060 HPS burnouts were converted to LED, a process that is relatively quick work on-site.[42] That means no more than 3,667 outages potentially involved more-complicated technical work, follow-up visits or site access difficulties that might justify delays in resolution. Yet there were 7,748 outages exceeding five days in length. This means there were at least 4,081 HPS fixture outages in which it took the Company more than five days to get a crew on site simply to install a new LED. After the Company switched over to converting burned out HPS fixtures to LED, in mid-2018, one would have expected delays attributable to difficult HPS repairs to disappear and give way to simple and quick LED conversions. Contrary to that expectation, however, average outage duration in 2019 remained at 8 days, exactly the same duration as in 2018.

Whatever the cause of changes in reliability performance from 2017 to 2019, it is notable that the Company has taken no notice in its case filings of its failure to meet – or even approach - its own streetlight outage resolution standard for the past two years and to suggest any remedy.

Q: To what extent are streetlight reliability problems caused by power outages?

A. Power outages account for no more than one-fourth of all streetlight outage hours; the clear majority can be attributed to streetlight equipment problems. As I will show, electric

[41] Witness Blumenstock, op cit.
[42] Witness Biller, discovery response U20697-MAUI-CE-735(b).

distribution reliability improvements the Company proposes in this case are projected to improve streetlight performance only slightly, but at very high marginal costs. In contrast, installing durable equipment (like LEDs) and preventively maintaining it can improve performance significantly while reducing costs. Unfortunately, the company offers no plans in this case that hold out the prospect of reduced streetlight outage time.

Q: What is the average annual streetlight outage time caused power outages?

A: The Company does not track power outages for streetlights separately, but we can assume that streetlights lose power with about the same frequency and duration as residential customers because they use substantially the same distribution lines.

For 2018, Consumers Energy reports SAIDI (System Average Interruption Duration Index) was 235 minutes excluding Major Event Days (MEDs).[43] Consumers projects SAIDI excluding MEDs to decline by 48 minutes per year to 187 minutes in 2022.

Streetlights are illuminated 4200 hours per year, or about 48% of the time. Therefore, comparing 2018 to 2022, the effective reliability improvement for streetlights will be about 23 minutes per year, down to an average of about 1-1/2 nighttime hours per year without power, if we assume that power outages are evenly distributed across daytime and nighttime hours.

This number is very small compared to the reported 12 hours of outage time per fixture per year attributed to streetlighting equipment problems, as reported above. Yet the reported 12 hours is itself almost certainly a substantial understatement, as I will explain below.

Thus, power outages cause at most a small minority of streetlight outages.

Q. How much will the company's projected increases in distribution system spending

[43] Company witness Blumenstock direct testimony, p.16-27.

cost street lighting customers?

A. The Company proposes to increase distribution system capital spending by $125 million from 2019 to 2021.[44] In 2021, the company proposes to allocate 0.73% of its total distribution system customer costs to the Lighting & Unmetered class. [45] Therefore, increasing distribution system by $125 million by 2021 would result in approximately $918,000 additional rate base being allocated to the Lighting & Unmetered class. At the Company's 6.09% return on rate base, the marginal increase in distribution system capital in 2021 will therefore increase required revenue on the Lighting and Unmetered class by about $56,000. The 2021 increase is not a single-year event, either, but is expected to continue for several years. We can safely predict that the distribution system spending surge will ultimately result in required revenue growth of $200,000 or more from the street lighting class. Since the company serves about 170,000 unmetered streetlights, the increase per light will be in the range of $1/year.

Q. How cost-effective are the proposed distribution system investments in terms of improvements to streetlight reliability?

A. An increase of $1/streetlight per year for 23 additional minutes illuminated equates to a marginal cost of $2.60/hour of additional illumination. For comparison, the Company's most common streetlight today, the 100-watt HPS, costs customers about 3.5 cents/hour.[46] There is no reason to believe that street lighting customers value reliability so much that they would be willing to pay 74x their baseline cost for better reliability when direct

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[44] Company witness Blumenstock direct testimony, Figure 4, p.20

[45] According to Company witness Aponte's workpaper "ex0220-Aponte-1-3 and WP-1-81", in the "Dist Customer Cost" worksheet, the Lighting & Unmetered Class will be allocated $1.7 million in 2021 out of total distribution customer costs of about $232 million, or about 0.73%.

[46] ($147.84/year)/(4,200 hours/year)

investments in street lighting equipment would be vastly more effective – as I will discuss below.

While street lighting customers undoubtedly would prefer less power outage time, the Company has proffered no evidence to show that the cost-benefit ratio of these expenditures is satisfactory to streetlighting customers. Company witness Houtz justifies the company's proposed reliability investment using calculations made by the Interruption Cost Estimator. In response to discovery question U20697-MAUI-CE-180, however, Houtz stated, "ICE does not factor in any costs incurred by streetlight customers." While safety and reliability of electric service are generally regarded as "must-haves" that are not subject to cost-benefit analyses, this is not a relevant standard for street lighting service. Safety benefits provided by street lighting are far more ambiguous and difficult to quantify than for residential, commercial or industrial customers.

This is not surprising. It stands to reason that street lighting customers would value distribution system reliability less than virtually any other class. During power outages, residential customers cannot heat or cool their homes, and begin to lose refrigerated food after a few hours. Commercial and industrial customers may have to close down entirely, send workers home, shut down production or turn away paying customers. In contrast, the company has presented no evidence of costs or inconveniences borne by street lighting customers during a power outage, nor any evidence that those customers would be willing to pay exorbitantly high marginal costs to slightly reduce outage frequency or duration. Recognizing this fact themselves, most utilities make streetlight restoration their lowest priority during an outage, and re-assign streetlight crews to more urgent tasks.

In sum, street lighting customers' needs are not the cause of rapidly increasing distribution system costs, they get little marginal benefit from these investments, and they should not have to pay for them. While street lighting customers are unlikely to object to rate impact of $1/year/fixture for greater system reliability, what does concern them is the lack of attention the Company gives in this rate case to far more important causes of streetlight outages. As I will discuss next, the Company should pursue several such alternatives that will have much greater impact on reliability and may actually reduce cost.

Q. To what extent are street lighting reliability problems caused by street lighting equipment failures?

A. Consumers' claimed total annual outage time per fixture in 2019 was 12.17 hours.[47] This figure cannot be correct, because witness Blumenstock wrote, "The Company does not track the number of streetlights affected by outages as requested."[48] Average outage time cannot be calculated without knowing how many fixtures are affected by each outage. A one-hour outage that affects only 1 out of 10 streetlights results in average outage time of 6 minutes per streetlight; but a one-hour outage that affects all 10 of those streetlights results in average outage time of one hour per streetlight. The Commission should order the Company to report outages time per fixture accurately in the future.

There are two reasons to believe that the average streetlight fixture was out for more than 12.17 hours in 2019:

- Outages are certainly longer on average than their reported duration. The clock starts ticking on an outage when it is first reported, and without networked lighting controls

[47] U20697 **Exhibit MAU-16**
[48] Witness Blumenstock, discovery response U20697-MAUI-CE-181(a)

there is no way to know how long the light has been out before then. There is no reason to believe that streetlight outages are reported nearly as promptly as residential outages, on average. People are less likely to notice them and less likely to be personally motivated to report them, compared to outages affecting their homes or businesses. Outages that start during the day may be effectively invisible until nighttime, causing a lengthy delay in reporting from onset. Outages that begin when most people are home and in bed may not be noticed until the next evening, or longer – already a longer outage duration than the company's reported 12-hour average.

- Second, we cannot assume that each outage affects only one fixture because circuit wiring, breaker and transformer problems can affect multiple fixtures.

Understated as the 12-hour figure may be in comparison to residential outage time per year, it demonstrates that street lighting equipment failures cause more than three times as much outage time for fixtures as do power outages.

Q. How does Consumers' streetlight outage performance compare to standards and norms?

A. I have already noted that the Company has significantly exceeded its own standard for outage duration for the past two years, holding steady at eight days where it has set a standard for an average no greater than five days.

For comparison, DTE Energy reported average streetlight outage duration of 3.5 days in 2018 (compared to 8 days for Consumers), with 64% of outages resolved in less than four days.[49]

[49] MPSC case U-20561, company exhibit A-25.

These statistics underline why streetlight outages are a sore point for municipal officials and community members. In 2019, Consumers reported average power outage duration (CAIDI) of 219 minutes.[50] That means the average streetlight outage event was more than 54 times as long as the average power outage – and that's without knowing how long the light was out before it got reported. People notice when a streetlight is off but the neighborhood has power; and they get irritated when it takes more than a week to fix it.

I linger on these figures, in comparison to proposed expenditures on distribution system reliability, to highlight that the Company is proposing general electric distribution system projects that are of trivial marginal benefit to streetlighting customers but come at great marginal expense, while making no proposals that directly address the reliability problems that actually vex streetlighting customers and community members.

Q: Why do you argue that reducing streetlight outage problems can reduce cost?

A: I can cite both logic and evidence to support this claim.

The basic logic is that every trip required to service a streetlight is expensive, more so than installing durable equipment and maintaining it well. Recall the evidence I provided earlier showing that labor time spent preparing for and traveling to a reported outage exceeds on-site labor, and in many cases also exceeds the cost of a new LED fixture. The proven solution is to install equipment that is highly reliable (i.e., LEDs) and use scheduled maintenance methods to service all fixtures in an area in one trip, before they break down, rather than making a unique trip for each failed fixture.

The evidence I can cite comes from DTE Energy.[51] Over the last ten years, DTE has reduced average outage duration from 8.5 to 3.5 days and has reduced the incidence of

[50] Company witness Blumenstock's direct testimony, p. 29, Figure 12.
[51] U20697 **Exhibit MAU-17**

outages longer than 10 days almost 90%. These significant improvements, which might be expected to increase costs, have coincided with very significant O&M cost reductions, from about $46/year per fixture in 2009 down to about $26/year per fixture in 2018. This period also coincides with the company's aggressive deployment of LED fixtures, and its adoption of preventive maintenance practices including periodic nighttime inspections of all fixtures by professional staff and scheduled group maintenance of fixtures.

Q. What are the Company's plans for improving its streetlight outage performance?

A. The Company's direct testimony does not directly address actions the Company is taking or plans to take to shorten streetlight outage durations, reduce the number of long-duration outages or the average outage time per fixture per year.

A related action the Company proposes is to develop a public online outage reporting portal. The online portal may result in quicker and more accurate reporting of outages but won't obviously shorten how long it takes to resolve them after the report is received, which is municipal officials' top reliability concern.

Q: Do you support the Company's plans to offer an online reporting system for streetlight outages?

A: Yes. The proposed system promises to make it easier for anybody to report an outage location accurately and the user-friendly interface should encourage more and faster reporting. It should also help ensure outages are reported to the right organization: community members can't tell whether a light belongs to Consumers, the municipal government or somebody else. Reducing the number of complaints about Consumers' lights misdirected to municipal officials would be a welcome outcome.

Q: How could the proposed online reporting system be improved?

A: The Company should consider offering a mobile app for reporting, such that people who notice outages while out and about don't have to remember to report it after they get to their destination. Community members could easily and instantly report the outage, and the app could add precise location data automatically. The app might see greatest adoption among municipal staff, police and utility workers, but other community members might also use it.

Q: What else should the Company do to improve reliability?

A: First, the Company should accelerate the LED conversion process. Second, the Company needs to identify why its outage duration performance is missing its target and implement fixes. Third, the Company should identify ways to reduce reliance on municipal officials and community members to identify and report outages. Fourth, the Company should develop management systems that support implementation of predictive and/or preventive maintenance practices.

Q: Why will expediting conversion to LED lighting improve reliability?

A: LEDs are less prone to outages than HID fixtures because they do not require lamp replacement every 5-8 years. This lamp-replacement cadence is the primary driver of the Company's LED conversion process: when an HID lamp in a cobrahead fixture burns out, rather than replacing the lamp, the Company removes the entire HID fixture and replaces it with a new LED fixture, which should last 20 years or more. Unfortunately, this means that some HID cobrahead fixtures will not be replaced until the eighth year of the burnout replacement program. Some HID fixtures may remain in place even longer, because mercury vapor lamps in particular often dim slowly over a long period of time without burning out and triggering an outage report.[52] Also, the Company has no fixed plans to convert decorative HID fixtures to LED.

Q: How can the Company best expedite the LED conversion process?

A: By undertaking planned, group conversions from HID to LED, rather than relying primarily on reactive conversions. Doing so would forestall burnouts that now result in reactive LED conversion, and customers would also start reaping the reliability and cost benefits of LEDs sooner.

Performing planned, group conversions has the additional reliability advantage that all fixtures in a contiguous area will have the same in-service date. This greatly facilitates preventive maintenance and predictive replacement, which is far more efficient than responding to future, random outage reports and prevents a significant proportion of outages. By keeping all the fixtures in a given area on the same service cycle, for example, DTE Energy is able to replace all HID lamps shortly before they reach the end of their predicted service lives, greatly reducing outages and O&M costs. Similarly, DTE predicts when dirt accumulation will reduce lumen output of all fixtures in a given area below prescribed levels, and schedules fixture cleaning before fixture performance falls short of roadway lighting standards.

[52] "Mercury vapor lamps have rapid lumen depreciation and continue to burn on but never burn out. While this may seem like a benefit, an MV lamp can put out as little as 10% of its initial lumen output while still using 100% of the electricity." https://www.accessfixtures.com/disappearance-mercury-vapor-lighting/

Q. What should the Company do to improve its outage restoration performance?

A. The Company needs to have dedicated streetlighting crews, both for outage response and for conversions.

Presently, crews who service streetlights also have other O&M duties. Rightly or wrongly, streetlight outages may get bumped to the bottom of the priority list, below power restoration for residences and businesses, for example. In addition, crews performing mixed O&M duties may not have the right materials and equipment, or expertise, to be able quickly to resolve a streetlight outage.

Overall, though, streetlight outage duration likely has less to do with what a crew does on site (e.g., install a new LED rather than repair an HID) than with how long it takes them to get there. We know this because, as I discussed earlier, Consumers has been able to address the vast majority of recent outages with a straightforward, quick LED conversion. Thus, the company should focus on shortening its response time, and having more staff capacity dedicated to streetlight outage restoration duties seems likely to help. If this solution is impractical for some reason, a solution used by many utilities is to contract with third-party providers for service restorations. DTE Electric, for example, contracts with third-party providers for outage restoration work, and tasks those contractors with performing periodic patrols of streetlights to proactively identify service and maintenance needs, many of which may not be apparent to the general public.

In addition, the Company should consider the use of advanced lighting controls, through which fixtures can self-monitor and predictively report performance issues and adopting preventive and predictive maintenance practices.

Q: How can advanced lighting controls improve reliability?

A: Advanced lighting controls, among other benefits, allow LED fixtures to self-monitor and report their status and support remote diagnosis and repair efforts. In many cases LEDs can report issues before they cause an outage, triggering preventive repair efforts. In the case of an outage they can immediately and specifically report the cause, supporting quick response and accurate resolution. These systems add cost, however, and adding them should be done only after careful consultation with customers, who can best articulate how to balance their need for reliable fixtures against their need to keep costs down. However, the company should move quickly, because it is buying and installing a lot of LEDs over the next several years. Buying LEDs with integrated controls will work better and cost less than retrofitting controls later at the cost of another visit to every fixture.

Q: Why should the Company directly inspect every fixture on a regular schedule?

A: The primary reason is that customers now feel the primary burden of monitoring the Company's equipment falls on them, and they are not happy about it. To satisfy community member expectations, some municipalities regularly incur significant overtime by assigning staff to nighttime light-assessment patrols and other staff to submitting reports to the Company; then revisiting lights to make sure problems have been resolved. While helpful and welcome, the Company's proposal to provide a more user-friendly online outage reporting tool unintentionally suggests that its only answer to reliability issues is for customers and community members to do a better job reporting problems.

Aside from demonstrating to customers that the Company takes first responsibility for reliability problems, Company patrols can do more comprehensive, complete and rigorous assessments than ad-hoc reports from the public and customers. Compared to members of the public, staff can more accurately identify fixtures that are out of compliance with technical lighting standards such as lumen depreciation, light trespass and glare problems, and can more accurately identify the causes of problems they note.

DTE Energy, for example, states, "In an effort to further bolster customer service, in 2019, DTE began to increase its night patrol activities with the intent of proactively identifying and repairing outages before they are reported by our customers. At DTE's direction, contractors are now responsible for patrolling all E1 Option I streetlights, with the expectation that each community with streetlights owned and operated by DTE will be visited at least once annually."[53]

When asked whether Consumers Energy has entertained implementation of a comparable monitoring program, company witness McLean replied, "This consideration is costly and would require daily support across all counties we serve in order to accurately log and track outages. Placing these resources on evening shifts would pull from day shift prioritization."[54] I disagree in that annual inspection of each community's lights need not require daily support. There would be some expense, but it would be offset substantially if not completely by more accurate reporting, greater efficiency of outage response efforts, increased customer satisfaction and reduced customer expenses incurred now to identify, report and track outages.

Q: What predictive and preventive maintenance practices would improve reliability?

A: Predictive and preventive maintenance has important advantages over reactive maintenance. While it may seem counterintuitive to replace lamps, fixtures or other

[53] MPSC case U-20561, DTE witness R.A. Bellini direct testimony, p.16.
[54] Company witness McLean reply to discovery question U20697-MAUI-CE-183.

equipment before the end of their predicted service lives – rather than after they fail – it is much cheaper to proactively replace all the equipment along a street at once than to make repeated trips as fixtures fail one by one. Recall, for example, that the Company's indirect labor cost of LED conversions significantly exceeds direct labor costs, indicating that time prepping for and traveling to outage restoration jobs is greater than the time spent on site. For that matter, indirect labor cost per fixture exceeds the cost of the Company's most common LEDs, meaning it may be more cost-effective to retire a 20-year old LED with 28% lumen depreciation than to make a unique trip to replace it two years later when it finally fails the L70 standard. In addition, preventive maintenance, by definition, prevents failures, which is the biggest complaint of community members and municipal officials. However, company witness Blumenstock stated, "The entirety of the referenced O&M spending for 2018 was reactive."[55]

To be clear, the Company should not maintain most HID fixtures preventively, but should replace them with LEDs even before they fail. Once LEDs are installed, preventive maintenance is possible only if the Company keeps careful records of when and where each fixture is installed, and is facilitated by group conversions such that all the fixtures in an area can receive scheduled maintenance on the same visit. LEDs remain a relatively new and quickly evolving technology with significant cost and quality variations among manufacturers; assuring that LEDs continue over time to meet lighting design standards will require direct monitoring.

For example, LEDs are less likely to "burn out" altogether; rather, they dim progressively

[55] Company witness Blumenstock reply to discovery question U20697-MAUI-CE-182 (9a).

over time and at some point in the future will fall below 70% of original lumen output (the L70 standard). Members of the public are not likely to notice and report any fixture that is putting out slightly too little light. An alternative to preventive maintenance, as discussed above, is the use of advanced lighting controls that can report fixture conditions, including before they cause outages.

Currently, however, the Company's information systems apparently do not support tracking of individual fixtures necessary to predict maintenance needs. Witness Blumenstock, in response to discovery question U20697-MAUI-CE-732, stated, "When work such as a streetlight conversion is completed in the field, information about the work is managed through a work order in the Company's SAP system. For planned work, the work order includes a drawing of the proposed work and captures as-built information as entered by field personnel. For reactive work, the order captures as-built information and a general location but does not capture specific customer information."

Without inventory records that identify specific location, customer, installation and maintenance dates of each fixture, and without adopting group conversion practices, the Company's ability to efficiently optimize performance and service life of its LED streetlight fleet will be badly hampered.

Finally, the Company should adopt predictive maintenance methods for HID lights it does not plan to convert to LED in the near term. At present, the Company has firm plans only to convert cobrahead lights to LED, because other kinds of light installations are less standardized and may not have cost-effective off-the-shelf LED solutions available. When the Company re-lamps an HID light (rather than converting it to LED), it should create a maintenance record that will trigger preventive re-lamping slightly before the new lamp is expected to reach end of life. This approach is effective because HID lamps are a mature technology with predictable service lives, and preventive re-lamping can prevent outages and incur lower outage response costs than one-off reactive re-lampings.

Q: What should the Commission order to improve the Company's streetlighting reliability performance?

A: The Commission should order standing credits for streetlight outages based on periodic, statistically representative sampling of each customer's fleet of company-owned fixtures. If 10% of fixtures are assessed not to be operating properly, then the municipality's bill should be reduced 10% until a subsequent sampling updates that figure. I suggest that sampling be conducted at least once every two years. Follow-up longitudinal inspection of individual non-functional fixtures should not be required to establish how long a credit should remain in effect; even if non-functioning fixtures are repaired in short order, it is reasonable to assume that others have stopped working in the meantime. If the Company believes that it has improved the percentage of lights operating to specification, it can conduct a new sampling of fixtures at any time. Until then, and regardless of how many fixtures the Company repairs, credits based on the population sample should remain in effect.

Q: Why should the Commission embrace such a substantial and potentially expensive change in reliability standards?

A: Because customers should not have to pay for more lights than are typically working at any given time, and they should not be saddled with heavy tracking and reporting burdens and onerous documentation and credit standards to get reliable service. If the Company cannot demonstrate that it can keep more than 95% of the streetlights in a municipality operating to specifications at the same time, it should not be able to charge the customer more than 95% of its base rate until it can prove it's doing better. Thus, my proposal creates clearer, more powerful incentives for the Company to provide reliable street lighting service and reduces the need for the Commission to create more-granular reliability standards and enforce them.

Q: Why should credits be based on system-wide statistics rather than on longitudinal tracking of each streetlight with reported problems?

A: Because identification and reporting of outages, and verification of resolution, is much too burdensome for a municipality with thousands of streetlights and is far out of proportion to the value of bill credits that might be received. As hard as it already is for a customer to track outages and claim credits, we know that longitudinal tracking of each individual streetlight outage results in substantial understatement of outage problems. As I have argued above, the Company's method for calculating average outage time per fixture clearly understates its reported duration; we know that there is a substantial, if unquantified, difference between reported and actual outage duration, owing to reporting delays; and we know that many outages affect more than one fixture. Requiring customers to identify, report and track outages longitudinally for each and every fixture for which they claim a credit cannot capture the true scope of the problem and is unduly burdensome for the customer – especially given that the equipment belongs to the Company. Automatic, system-wide credits create a powerful incentive for the Company, should sharply reduce burdens on customers and on the Commission to monitor and regulate performance, and most importantly should result in much more reliable service for customers.

Q: With nearly 200,000 streetlights in its system, some are bound not to be operating at any given time, and for reasons not always in the Company's control. Why should the Company be held financially responsible for these outages?

A: Because it is the Company's equipment. The customer should not bear the consequences of the Company's purchasing, monitoring and maintenance decisions over which the customer has effectively no influence. Customers should no more be responsible for monitoring the Company's equipment than the Company is for monitoring customers' equipment. The Company has various technological and operational means of improving system monitoring and performance that are more systematic and comprehensive than any foreseeable reporting system that relies on user reports, and it should have incentives to adopt them. Technical monitoring of streetlight performance becomes even more important as the LED population grows, because LEDs characteristically undergo slow, progressive lumen depreciation rather than burnout that community members might notice and report.

Q: How should the Commission ensure that customers have accurate information about the performance of their streetlight fleets?

A: The Commission should order the Company to provide each street lighting customer with an annual report with accurate statistics on number of reported outages in their jurisdiction, average outage time per fixture, number of outages exceeding five days, number of streetlights not in compliance with operating standards at last full assessment, and total value of bill credits issued in the preceding year. In addition to reliability statistics, reports should state number of LED conversions performed and the energy efficiency gain realized from them.

Q: Please summarize what you recommend the Commission order with respect to streetlight reliability?

A: The Commission should order the Company to issue automatic bill credits for whatever percentage of a customer's streetlights are found by field assessment to be out of compliance with reliability standards, and for those bill credits to remain in force until a subsequent assessment demonstrates that the percentage of fixtures in compliance with standards has change.

The Commission should order the Company to provide each streetlighting customer with an annual report with accurate outage and restoration statistics for their streetlight fleets, and bill credits issues for outages.

X. THE COMPANY'S POLICY OF ASSESSING REMOVAL FEES ON CUSTOMERS IS UNJUST AND CREATES INEFFICIENCIES IN PUBLIC LIGHTING SYSTEMS

Q: Why might a customer want to remove a streetlight?

A: Municipalities may wish to remove streetlights for several reasons. First, changes or shifts in population or traffic patterns may reduce the need for a streetlight at any given location. Second, budget constraints or policy changes may cause a customer to conclude that lighting at a given location should be discontinued. Third, customers may wish to terminate their lighting contracts with the Company, in which event the Company may decide to remove its equipment or be required by the customer to remove its equipment from public easements. Fourth, road projects may require relocation of poles and fixtures.

Q: Are streetlight removal fees currently assessed by the Company high?

A: Yes. Please see my **Exhibit MAU-18**, an email exchange between a representative of the City of Flint and the Company discussing costs to remove two poles with two fixtures each. The quoted cost was $3,458. The net cost included a small salvage credit, apparently representing scrap value of removed equipment. Most poles have only one fixture, and a $1,700 removal cost per pole is roughly equivalent to ten years of tariff payments for a typical HID light fixture. Because of the high cost of removal, the City did not authorize the work, and the fixtures are presumably still in place, costing the City around $600 per year (four fixtures at about $150 each per year, depending on technology and wattage) for lighting the City does not want. My anecdotal understanding, gleaned in conversations with MI-MAUI members and other municipalities, is that they seldom consider fixture removal because the costs are so high.

I am supplying this anecdotal evidence because the Company did not provide comprehensive data on this topic in response to discovery requests. My discovery question U20697-MAUI-CE-184(c) requested "aggregate data for all customer-requested streetlight removals in the historical test year…". In response, witness Blumenstock stated, "Individually considering all streetlight orders to identify removals and specific customer contributions would be extremely burdensome because the information is exceptionally voluminous."

Whether customer-requested removals are rare or "voluminous", customer contributions to removal costs are important. If rare, a likely cause is the high removal costs the Company assesses. If "voluminous", a lot of customer money is at stake and we should make sure it is being calculated correctly and assessed fairly.

Q: If a customer wants to discontinue lighting with Company-owned equipment at a given location, what options does it have short of paying for removal?

A: The customer can pay a disconnection fee and reduced tariff. The Company's tariff sheet D-51,00 reads: *"For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged."*

Q: **Is disconnection a workable option for customers who wish to reduce or reconfigure streetlights**?

A: No. Savings of 40% are insufficient to go to the trouble of disconnecting a light. For example, the tariff for a typical residential street fixture is about $160 per year and would be almost $100 per year if disconnected. Even if homes closest to that streetlight are no longer occupied, savings from disconnection are too small to incur administrative costs and potential objections from nearby residents.

In addition, the tariff permits disconnection only "for energy conservation purposes." Customers wishing to save energy are more likely to want LED fixtures; they seek disconnection or removal for other reasons, described above.

Q: Why do you argue that removal fees as assessed by the Company are unjust?

A: Because customers have already paid these costs. They should not have to pay twice for the same service.

Per Federal Energy Regulatory Commission accounting standards, depreciation base includes not only the cost of buying and installing equipment, but also "net salvage value". Net salvage value has two components: the remaining value of an asset after the Company removes it from service (often, resale or scrap value) minus the cost of removal. Streetlight fixtures and poles have little or no value at the end of their service lives but have high removal costs. Therefore, net salvage value for streetlighting equipment (FERC account 373) is negative.

In response to discovery question U20697-MAUI-CE-738, witness Blumenstock stated, "In the Company's most recent depreciation case, in Case No. U-17653, FERC account 373 included -30% net salvage in determination of the depreciation rate." FERC account 373 is for street lighting costs.

To illustrate, this means that when the Company installs a new pole, suspension and fixture, at a typical cost of $3,000, it includes an additional 30%, or $900, in depreciation base as net salvage value, for a total of $3,900. Because net salvage value is included in depreciation, it is recovered in streetlight tariffs, meaning that the customer pre-pays removal cost over the lifetime of the asset. Assessing additional removal costs when a customer requests removal therefore charges them twice for a service they already paid for.

Q: What if the actual cost of removing a streetlighting asset is less than its net salvage value included in depreciation base?

A: Any net salvage value should go on the Company's books as reduction of net book value. If it turns out over time that the average salvage event has greater cost, then the next time that depreciation rates are set, they include the updated salvage cost. Over time, customers pay through rates and the Company is "made whole" for the salvage cost.

The customer is not responsible for actual removal costs in excess of net salvage value for a specific project. It is the Company's responsibility to add a correct amount for net salvage value to depreciation base and to collect on that amount from the customer over time. It is therefore important for the Company to set an accurate net salvage value for streetlighting assets.

Q: How does the Company account for net salvage value when calculating costs it charges for customer-requested removals?

A: The Company apparently does not consider net salvage value at all when determining customer contributions for customer-requested removals. In response to discovery question U20697-MAUI-CE-739, witness Blumenstock stated, "The Company provides a salvage credit for each light removed when providing the customer with a design estimate for a given removal project. This salvage credit is deducted from what is billed to the customer."

This response is consistent with my **Exhibit MAU-18** from Flint, in which the cost detail shows a salvage credit of $45 but otherwise no credit for net salvage value. While the “salvage credit” is not further described, it is clearly not net salvage value, which should be hundreds of dollars per my example above. I interpret “salvage credit” to be either the scrap or resale value of the asset, without any consideration of removal costs that the customer has been pre-paying through depreciation since the asset was installed.

Q: Why doesn’t the Company credit net salvage value toward customer-requested removal costs?

A: Because it doesn’t know the net salvage value for individual fixtures. In response to discovery question U20697-MAUI-CE-184, witness Blumenstock explained, “The Company does not maintain a net book value for individual streetlight fixtures.” Net salvage value is derived from net asset value; therefore, the Company cannot know net salvage value for individual fixtures, either. However, the difficulty of arriving at a net salvage value for a specific fixture or other asset does not justify setting that value to zero.

Q: If the Company cannot accurately calculate net asset value for fixture that the customer wants removed, how can it accurately calculate what removal costs to assess?

A: It already has – and it has already collected those costs, through depreciation charges included in tariff payments. Whether any given fixture has been in service long enough for the customer to have paid off the full depreciation base is relatively inconsequential, since the Company can make up any shortfall by adjusting net salvage value in subsequent rate cases.

Q: If customers can have street lighting assets removed without paying any unrecovered net asset value or salvage value, won't that unfairly impose those costs on remaining customers?

A: This concern holds water only if the Company believes that a large number of customers are unhappy with its streetlighting services and will wish to remove fixtures and/or cancel contracts. If that is the case, the better response is to improve costs and service to make those customers happy rather than to handcuff them to services they no longer wish to receive via punitive exit fees.

If, on the other hand, the Company supports efficient deployment of lighting services and is comfortable with accountability for its costs and quality of service, it should support this proposal.

Q: Why should the Commission support this change in streetlight removal policies?

A: Foremost, because it's fair. Customers should not pay costs twice or be stuck paying for lights they do not want because of prohibitive exit fees.

When the Company removes a light from service, most commonly because it's old, it does not charge the customer an out-of-pocket fee for that service. It charges removal costs to depreciation reserve and adds costs for buying and installing a new fixture to rate base. On the other hand, if the customer asked the company to remove that very same fixture and not install a new one, the amount of removal work would be exactly the same, but under the Company's current practices they would charge the customer fees in line with the example I provided earlier from Flint, and ignore all the net salvage value payments the customer has made on that fixture over the years.

A collateral, but ultimately more important, reason for the Commission to adopt this proposal is that it creates incentives for the Company to deliver responsive and cost-effective street lighting services without need of constant Commission oversight. Today, the Company has diluted financial incentive to deliver efficient and responsive services because customers have no alternatives: they have no feasible means of cancelling, right-sizing or even redeploying their streetlighting deployments without incurring exit fees that overwhelm any potential benefits; and now, with the Company's switch to automatic, no-cost LED conversions, customers don't even get to choose when their lights are converted or what LEDs are installed. If customers determine that they need fewer lights, or that they wish to own and manage their lighting systems themselves to reap cost efficiencies or install advanced lighting controls and smart city features that the Company does not offer, they should be able to do so.

Q: Should customers be able to acquire street lighting assets from the Company to take over ownership and management of their streetlighting systems?

A: Yes. This is a logical extension of the no-cost removal policy I recommend above. If a customer wishes to cancel its lighting contract entirely, the Company may choose to remove all the equipment and charge the expense to depreciation reserve. If the Company chooses not to remove the equipment because it cannot recover additional costs from the Company, it may be presented with an order from the customer to remove its equipment from public easements.

However, an alternative to removal that may be attractive to both parties is for the Company to sell the equipment to the customer. This alternative should be attractive to the customer because it avoids enormous disruption caused by removal and replacement operations and provides the customer an enormous leg up in configuring a municipally owned system. This alternative should be attractive to the Company because it allows it to recover some value for the assets that it would otherwise have to remove and scrap at its own expense – or, more precisely, at the expense of remaining customers who absorb the difference through adjustments to the net salvage value rate going forward.

This consideration is why I recommend that transfer of ownership should require payment. Removal of individual streetlighting assets from service, and absorption through rates of their net asset value, is relatively inconsequential to other customers. Removal and scrapping of an entire municipality's lighting system, however, arguably imposes unreasonable burdens on remaining ratepayers, not to mention the waste of scrapping perfectly good equipment.

Q: How should the sale price of street lighting assets be calculated?

A: When a customer wishes to cancel its lighting contract with the Company and instead own and manage its own lighting system, the customer should pay the Company a reasonable estimation of net asset value of the system. Because the Company does not track values or installation dates of individual streetlighting assets, that value must be approximated. The simplest approach, which is also reasonably fair, is for the Company to calculate an average net asset value for its system and multiply that average by the number of fixtures the customer wishes to purchase.

Q: How might the Company assign net asset value and net salvage value to individual fixtures that are group-depreciated?

A: Because the Company knows how many luminaires, poles and other street light assets it has, and knows the amount held in depreciation reserve for account 373 (Streetlighting), it can readily derive an average net asset value and average net salvage value for any type of asset.

To illustrate, the Company's 2021 test year net asset value of distribution streetlighting Plant In Service under the GU-LED rate is projected to be $77,959,000.[56] Total Distribution Depreciation Reserve for GU-LED is projected to be $56,991,000.[57] The net asset value under GU-LED will therefore be $20,968,000. In 2021, the Company expects to have 81,449 LED fixtures in service.[58] The average net asset value of LED luminaires, including other streetlighting equipment such as poles, brackets, transformers and wiring, will therefore be $257. For every LED luminaire, and associated assets, that a customer wishes to acquire from the Company, it should pay that amount.

Q: Please summarize your recommendations regarding the Company's removal policies and fees.

A: The Commission should order the Company to stop assessing streetlight removal fees.

The Commission should order the Company to transfer ownership of streetlighting assets

[56] U20697-MAUI-CE-724-Aponte_ATT_1, cell E25.
[57] Witness Aponte, workpaper ex0220-Aponte-1-3 and WP-1-81, "Dist" worksheet, cell AZ670.
[58] Witness Miller, workpaper ex0220-Miller-1-3 and WP-1-25, cell G35.

to customers, upon request, at average system net asset value.

XI. RECOMMENDATIONS AND CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission disallow excessive costs for past LED conversions to be added to rate base.

I recommend that the Commission cap the Company's LED conversion costs for cobra head fixtures at an average no greater than $300 per fixture including loadings.

The Commission should order the Company to issue bill credits to all customers who paid for LED conversions, fully offsetting rate increases caused by LED conversion costs added to rate base, until 2032 or until such time as the Company can demonstrate that more than 50% of LEDs installed before 2018 have failed off-warranty and been replaced.

I recommend that the Commission limit the Company's ability to recover costs if it buys technologically outdated street lighting equipment that falls short of current standards for energy efficiency, illumination quality and service life.

The Commission should approve the Company's proposal to replace center-suspension streetlights with pole-mounted LEDs at no out-of-pocket cost to the customer. The Commission should not approve the Company's projected costs or lighting design for these LED conversions, and should instruct the Company to revise its plans to provide cost-competitive services that meet roadway lighting standards.

The Commission should order the Company to implement a single, unified unmetered lighting rate for Company-owned fixtures, that charges customers the same amount for equivalent lighting regardless of fixture technology type.

The Commission should order the Company to implement a single, unified tariff for customer-owned lights based on electricity usage.

The Commission should order the Company to:

- Correct total Distribution Plant In Service to reflect HID luminaire retirements projected through 2021;
- Change its method for allocating streetlighting assets other than luminaires according to luminaire type. Poles, brackets and suspension arms should be allocated by fixture count, and wiring and transformers should be allocated according to electricity use.

If the Commission chooses not to order the Company to adopt a single unified unmetered lighting tariff per my preceding recommendation, then the Commission should also order the Company to revise its method for allocating streetlighting O&M costs, using fixture count rather than luminaire Plant In Service values to fairly allocate costs between GUL and GU-XL rates.

The Commission should order the Company to issue automatic bill credits for whatever percentage of a customer's streetlights are found by field assessment to be out of compliance with reliability standards, and for those bill credits to remain in force until a subsequent assessment demonstrates that the percentage of fixtures in compliance with standards has change.

The Commission should order the Company to provide each streetlighting customer with an annual report with accurate outage and restoration statistics for their streetlight fleets, and bill credits issues for outages.

The Commission should order the Company to stop assessing streetlight removal fees.

The Commission should order the Company to transfer ownership of streetlighting assets to customers, upon request, at average system net asset value.

Q. Does that complete your testimony?

A. Yes.

U20697

MI-MAUI witness Bunch

U20697 Exhibit MAUI-14

Combined unmetered lighting rate

LED range (watts)	HPS watts	MH watts	Incand watts	Fluor watts	Energy charge	Delivery charge	Monthly cost
15-24			202		$ 2.86	$ 5.00	$ 7.86
25-34			405		$ 4.28	$ 5.00	$ 9.28
35-44	117				$ 5.71	$ 5.00	$ 10.71
45-54		0	690		$ 7.14	$ 5.00	$ 12.14
55-64		0			$ 8.57	$ 5.00	$ 13.57
65-74	171				$ 10.00	$ 5.00	$ 15.00
75-84		0			$ 11.42	$ 5.00	$ 16.42
85-94					$ 12.85	$ 5.00	$ 17.85
95-104					$ 14.28	$ 5.00	$ 19.28
105-114	247			470	$ 15.71	$ 5.00	$ 20.71
115-124	318	9912			$ 17.14	$ 5.00	$ 22.14
125-134					$ 18.57	$ 5.00	$ 23.57
135-144					$ 19.99	$ 5.00	$ 24.99
145-154					$ 21.42	$ 5.00	$ 26.42
155-164					$ 22.85	$ 5.00	$ 27.85
165-174					$ 24.28	$ 5.00	$ 29.28
175-184					$ 25.71	$ 5.00	$ 30.71
185-194					$ 27.13	$ 5.00	$ 32.13
195-204					$ 28.56	$ 5.00	$ 33.56
205-214	480				$ 29.99	$ 5.00	$ 34.99

Exhibit U20697 MAUI-n (RJB-14)

Round two

Item	Description	Price	Arden	Maverick	K Elec.	Siemens	PRT	Multiplier	Arden	Maverick	K Elec.	Siemens	PRT
E1-1	Journeyman Electrician/Lineman	$____	$85.00	$82.33	$91.00	$129.00	$145.00	150	$12,750.00	$12,349.50	$13,650.00	$19,350.00	$21,750.00
E1-2	Journeyman Electrician/Lineman – Overtime	$____	$120.00	$122.49	$133.00	$155.00	$195.00	60	$7,200.00	$7,349.40	$7,980.00	$9,300.00	$11,700.00
E1-3	Apprentice Electrician/Lineman	$____	$65.00	$72.33	$55.00	$103.00	$120.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-4	Apprentice Electrician/Lineman – Overtime	$____	$95.00	$104.87	$77.00	$122.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-5	Lamp and Photocell Service Person	$____	$85.00	$82.33	$91.00	$103.00	$120.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-6	Laborer	$____	$70.00	$75.12	$91.00	$125.00	$136.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-7	Laborer – Overtime	$____	$100.00	$110.38	$133.00	$152.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-8	Truck (35 to 40 foot insulated bucket truck)	$____	$45.00	$30.00	$35.00	$26.00	$31.00	200	$9,000.00	$6,000.00	$7,000.00	$5,200.00	$6,200.00
E1-9	Dump truck (2 to 3 yard)	$____	$35.00	$30.00	$35.00	$26.00	$75.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-10	Crane (5 to 10 ton)	$____	$100.00	$55.00	$69.00	$26.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-11	Pole truck with pole auger	$____	$120.00	$55.00	$35.00	$112.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
	Extra Work Note E1-12 thru E1-19 apply to standard cobra head fixtures only and include labor and materials.	All prices below										$0.00	
E1-12	Service call replace 35 to 150 watt bulb and standard photocell labor plus material. HPS, MV, MH fixtures	$____	$325.00	$122.50	$275.00	$99.00	$525.00	100	$32,500.00	$12,250.00	$27,500.00	$9,900.00	$52,500.00
E1-13	Service call replace 250-400w watt bulb and standard photocell labor plus material. HPS, MV, MH fixtures and flood lights	$____	$335.00	$132.50	$268.00	$99.00	$580.00	25	$8,375.00	$3,312.50	$6,700.00	$2,475.00	$14,500.00
E1-14	Service call to replace HPS starter (all Wattages)	$____	$450.00	$215.00	$272.00	$95.00	$550.00	25	$11,250.00	$5,375.00	$6,800.00	$2,375.00	$13,750.00
E1-15	Service call to replace HID ballast (all Wattages, Voltages, types)	$____	$475.00	$215.00	$383.00	$120.00	$600.00	25	$11,875.00	$5,375.00	$9,575.00	$3,000.00	$15,000.00
E1-16	Fuse (streetlight KTK) all fixtures	$____	$260.00	$66.00	$250.00	$84.00	$550.00	25	$6,500.00	$1,650.00	$6,250.00	$2,100.00	$13,750.00
E1-17	Replace Cobra lens (dish or flat lens)	$____	$285.00	$56.00	$300.00	$51.00	$550.00	25	$7,125.00	$1,400.00	$7,500.00	$1,275.00	$13,750.00
E1-18	Service call to replace HPS fixture including the fixture and photocell 50-150 Watt HPS	$____	$550.00	$215.00	$498.00	$182.00	$600.00	25	$13,750.00	$5,375.00	$12,450.00	$4,550.00	$15,000.00
E1-19	Service call to replace HPS fixture including the fixture and photocell 250 Watt HPS	$____	$625.00	$215.00	$541.00	$208.00	$650.00	25	$15,625.00	$5,375.00	$13,525.00	$5,200.00	$16,250.00
	Prices below are installed prices including materials and labor-mast arms are 2 inch galvanized heavy duty mast arms.												
E1-20	3 foot mast arm w/hardware w/o fixture	$____	$615.00	$293.00	$350.00	$155.00	$600.00	25	$15,375.00	$7,325.00	$8,750.00	$3,875.00	$15,000.00
E1-21	4 foot mast arm w/hardware w/o fixture	$____	$625.00	$325.00	$350.00	$155.00	$610.00	25	$15,625.00	$8,125.00	$8,750.00	$3,875.00	$15,250.00
E1-22	6 foot mast arm w/hardware w/o fixture	$____	$650.00	$358.00	$377.00	$134.00	$620.00	25	$16,250.00	$8,950.00	$9,425.00	$3,350.00	$15,500.00
E1-23	8 foot mast arm w/hardware w/o fixture	$____	$670.00	$480.80	$485.00	$321.00	$630.00	25	$16,750.00	$12,020.00	$12,125.00	$8,025.00	$15,750.00
E1-24	10 foot mast arm w/hardware w/o fixture	$____	$690.00	$574.00	$755.00	$275.00	$640.00	25	$17,250.00	$14,350.00	$18,875.00	$6,875.00	$16,000.00
E1-25	12 foot mast arm w/hardware w/o fixture	$____	$700.00	$644.00	########	$454.00	$700.00	25	$17,500.00	$16,100.00	$27,025.00	$11,350.00	$17,500.00
E1-26	Price add to E1-20 through E1-25 to include install supplied Fixture		$260.00	$78.00	$78.00	$78.00	$100.00	25	$6,500.00	$1,950.00	$1,950.00	$1,950.00	$2,500.00
E1-27	Install supplied fixture on existing mast arm single call out-warranty replacement	$____	$325.00	$127.50	$315.00	$78.00	$500.00	150	$48,750.00	$19,125.00	$47,250.00	$11,700.00	$75,000.00
E1-28	Service call replace failed fixture/control w/commissioning Warranty Labor only	$____	$2,375.00	$127.50	$250.00	$104.00	$550.00	25	$59,375.00	$3,187.50	$6,250.00	$2,600.00	$13,750.00
E1-29	Service call replace fixture/photocell w/o commissioning Warranty replacement	$____	$350.00	$127.50	$315.00	$78.00	$535.00	25	$8,750.00	$3,187.50	$7,875.00	$1,950.00	$13,375.00
E1-30	Hourly Electrician labor rate with Bucket truck to install ancillary equipment (less than 15 lbs) on mast arm.	$____	$150.00	$107.50	$126.00	$155.00	$176.00	25	$3,750.00	$2,687.50	$3,150.00	$3,875.00	$4,400.00
E1-31	Complete installation 6 ft. mast arm with wiring and supplied LED fixture and Control device on existing utility pole with commissioning. (New Install where there is no light currently. Provide sufficient pigtail for EVERSOURCE to connect to secondary line.)	$____ ___ _.__	$875.00	$428.00	$378.00	$391.00	$700.00	25	$21,875.00	$10,700.00	$9,450.00	$9,775.00	$17,500.00
E1-32	Complete installation 6 ft. mast arm with internal wiring and supplied LED fixture and Control device on existing utility pole w/o commissioning. New install where no light currently exists. Provide sufficient Pigtail on power side for EVERSOURCE to make connection to secondary.	$____ ___ _.__	$800.00	$426.00	$378.00	$324.00	$575.00	30	$24,000.00	$12,780.00	$11,340.00	$9,720.00	$17,250.00
E1-33	Service call to replace failed photocell/control device with commissioning	$____	$275.00	$132.00	$250.00	$195.00	$550.00	25	$6,875.00	$3,300.00	$6,250.00	$4,875.00	$13,750.00
E1-34	Rewire fixture internally or change internal fixture setting		325		$0.00	$268.00	$535.00	25	$8,125.00	$0.00	$0.00	$6,700.00	$13,375.00
E1-35	Replace photocell receptacle with approved ANSI 136.41 seven pin receptacle. Includes providing receptacle.	$____	$275.00	$156.00	$279.00	$190.00	$550.00	25	$6,875.00	$3,900.00	$6,975.00	$4,750.00	$13,750.00
E1-36	Install 35 ft aluminum pole of a quality as good or better than the US NSTAR specifications on existing foundation (Assume foundation is serviceable) with six foot mast arm and 150 watt HPS cobra head cutoff fixture	$____	$3,500.00	########	########	$2,743.00	$4,000.00	25	$87,500.00	$75,450.00	$76,000.00	$68,575.00	$100,000.00
E1-37	Transfer existing mast arm with fixture from old pole to replacement pole in connection with utility company pole replacement.	$____ each	$480.00	$214.00	$315.00	$268.00	$450.00	300	$144,000.00	$64,200.00	$94,500.00	$80,400.00	$135,000.00
E1-38	Remove broken non utility wooden pole (assume approximately one to two feet of the old pole is left above ground as from a knockdown) and install new 35 foot wooden pole with standard six foot bracket and supplied LED fixture. Dispose of old pole	$____ each	$2,300.00	########	########	$881.00	$3,800.00	25	$57,500.00	$56,475.00	$43,800.00	$22,025.00	$95,000.00
E1-39	Labor to rewire defective mast arm wires and reconnect light fixture. Complete cost for labor, travel and equipment. Wire to be billed based on per foot price next item below. Price for this line does not include wire price.	$____ each	$500.00	$284.00	$250.00	$194.00	$535.00	25	$12,500.00	$7,100.00	$6,250.00	$4,850.00	$13,375.00
E1-40	Replace defective mast arm wires with appropriately rated wiring for up to 250 watt fixtures. Price is wire only.	$____	$2.00	$1.77	$0.18	$7.00	$10.00	25	$50.00	$44.25	$4.50	$175.00	$250.00
E1-41	Install approved Fuse holder and Fuse in connection with service call.	$___N /A___	$80.00	$72.00	$7.50	$79.00	$100.00	25	$2,000.00	$1,800.00	$187.50	$1,975.00	$2,500.00
E1-42	Service call price-cost to respond to a service call and trouble shoot the light with no work required at the scene	$____	$260.00	$214.00	$250.00	$51.00	$535.00	85	$22,100.00	$18,190.00	$21,250.00	$4,335.00	$45,475.00
E1-43	**Deduct** for labor to install a fuse holder and fuse for any service call where the fuse is already installed	-$___N /A	-$45.00	-$72.00	-$7.50	-$16.00	-$5.00		$0.00	$0.00	$0.00	$0.00	$0.00
E1-44	Standard Material Markup	___%	10%	7%	15%	20%	25%		$0.00	$0.00	$0.00	$0.00	$0.00
A1-1	Change head without commissioning		$150.00	$79.75	$65.00	$86.74	$110.00	10000	###########	$797,500.00	$650,000.00	$867,400.00	###########
A1-2	Change head with commissioning		$180.00	$379.50		$106.26			$0.00	$0.00	$0.00	$0.00	$0.00
A1-3	HPS per month (I have assumed four months just to gauge impact not a bid item in the final tally)..		$1.20	$2.25	$1.53	$1.65	$2.90	1000	$1,200.00	$2,250.00	$1,530.00	$1,650.00	$2,900.00
D1A1	Emergency response		$260.00	$428.00	$252.00	$311.00	$535.00	36	$9,360.00	$15,408.00	$9,072.00	$11,196.00	$19,260.00
D1-A2	Emergency Response after hours		$375.00	$578.00	$800.00	$363.00	$675.00	36	$13,500.00	$20,808.00	$28,800.00	$13,068.00	$24,300.00
D1-A3	Emergency response Holiday rate								$0.00	$0.00	$0.00	$0.00	$0.00

Exhibit U20697 MAUI-n (RJB-15)

Round two

Item	Description	Price	Arden	Maverick	K Elec.	Siemens	PRT	Multiplier	Arden	Maverick	K Elec.	Siemens	PRT
E1-1	Journeyman Electrician/Lineman	$____	$85.00	$82.33	$91.00	$129.00	$145.00	150	$12,750.00	$12,349.50	$13,650.00	$19,350.00	$21,750.00
E1-2	Journeyman Electrician/Lineman – Overtime	$____	$120.00	$122.49	$133.00	$155.00	$195.00	60	$7,200.00	$7,349.40	$7,980.00	$9,300.00	$11,700.00
E1-3	Apprentice Electrician/Lineman	$____	$65.00	$72.33	$55.00	$103.00	$120.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-4	Apprentice Electrician/Lineman – Overtime	$____	$95.00	$104.87	$77.00	$122.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-5	Lamp and Photocell Service Person	$____	$85.00	$82.33	$91.00	$103.00	$120.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-6	Laborer	$____	$70.00	$75.12	$91.00	$125.00	$136.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-7	Laborer – Overtime	$____	$100.00	$110.38	$133.00	$152.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-8	Truck (35 to 40 foot insulated bucket truck)	$____	$45.00	$30.00	$35.00	$26.00	$31.00	200	$9,000.00	$6,000.00	$7,000.00	$5,200.00	$6,200.00
E1-9	Dump truck (2 to 3 yard)	$____	$35.00	$30.00	$35.00	$26.00	$75.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-10	Crane (5 to 10 ton)	$____	$100.00	$55.00	$69.00	$26.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
E1-11	Pole truck with pole auger	$____	$120.00	$55.00	$35.00	$112.00	$175.00	0	$0.00	$0.00	$0.00	$0.00	$0.00
	Extra Work Note E1-12 thru E1-19 apply to standard cobra head fixtures only and include labor and materials.	All prices below										$0.00	
E1-12	Service call replace 35 to 150 watt bulb and standard photocell labor plus material. HPS, MV, MH fixtures	$____	$325.00	$122.50	$275.00	$99.00	$525.00	100	$32,500.00	$12,250.00	$27,500.00	$9,900.00	$52,500.00
E1-13	Service call replace 250-400w watt bulb and standard photocell labor plus material. HPS, MV, MH fixtures and flood lights	$____	$335.00	$132.50	$268.00	$99.00	$580.00	25	$8,375.00	$3,312.50	$6,700.00	$2,475.00	$14,500.00
E1-14	Service call to replace HPS starter (all Wattages)	$____	$450.00	$215.00	$272.00	$95.00	$550.00	25	$11,250.00	$5,375.00	$6,800.00	$2,375.00	$13,750.00
E1-15	Service call to replace HID ballast (all Wattages, Voltages, types)	$____	$475.00	$215.00	$383.00	$120.00	$600.00	25	$11,875.00	$5,375.00	$9,575.00	$3,000.00	$15,000.00
E1-16	Fuse (streetlight KTK) all fixtures	$____	$260.00	$66.00	$250.00	$84.00	$550.00	25	$6,500.00	$1,650.00	$6,250.00	$2,100.00	$13,750.00
E1-17	Replace Cobra lens (dish or flat lens)	$____	$285.00	$56.00	$300.00	$51.00	$550.00	25	$7,125.00	$1,400.00	$7,500.00	$1,275.00	$13,750.00
E1-18	Service call to replace HPS fixture including the fixture and photocell 50-150 Watt HPS	$____	$550.00	$215.00	$498.00	$182.00	$600.00	25	$13,750.00	$5,375.00	$12,450.00	$4,550.00	$15,000.00
E1-19	Service call to replace HPS fixture including the fixture and photocell 250 Watt HPS	$____	$625.00	$215.00	$541.00	$208.00	$650.00	25	$15,625.00	$5,375.00	$13,525.00	$5,200.00	$16,250.00
	Prices below are installed prices including materials and labor-mast arms are 2 inch galvanized heavy duty mast arms.												
E1-20	3 foot mast arm w/hardware w/o fixture	$____	$615.00	$293.00	$350.00	$155.00	$600.00	25	$15,375.00	$7,325.00	$8,750.00	$3,875.00	$15,000.00
E1-21	4 foot mast arm w/hardware w/o fixture	$____	$625.00	$325.00	$350.00	$155.00	$610.00	25	$15,625.00	$8,125.00	$8,750.00	$3,875.00	$15,250.00
E1-22	6 foot mast arm w/hardware w/o fixture	$____	$650.00	$358.00	$377.00	$134.00	$620.00	25	$16,250.00	$8,950.00	$9,425.00	$3,350.00	$15,500.00
E1-23	8 foot mast arm w/hardware w/o fixture	$____	$670.00	$480.80	$485.00	$321.00	$630.00	25	$16,750.00	$12,020.00	$12,125.00	$8,025.00	$15,750.00
E1-24	10 foot mast arm w/hardware w/o fixture	$____	$690.00	$574.00	$755.00	$275.00	$640.00	25	$17,250.00	$14,350.00	$18,875.00	$6,875.00	$16,000.00
E1-25	12 foot mast arm w/hardware w/o fixture	$____	$700.00	$644.00	$1,081.00	$454.00	$700.00	25	$17,500.00	$16,100.00	$27,025.00	$11,350.00	$17,500.00
E1-26	Price add to E1-20 through E1-25 to include install supplied Fixture		$260.00	$78.00	$78.00	$78.00	$100.00	25	$6,500.00	$1,950.00	$1,950.00	$1,950.00	$2,500.00
E1-27	Install supplied fixture on existing mast arm single call out-warranty replacement	$____	$325.00	$127.50	$315.00	$78.00	$500.00	150	$48,750.00	$19,125.00	$47,250.00	$11,700.00	$75,000.00
E1-28	Service call replace failed fixture/control w/commissioning Warranty Labor only	$____	$2,375.00	$127.50	$250.00	$104.00	$550.00	25	$59,375.00	$3,187.50	$6,250.00	$2,600.00	$13,750.00
E1-29	Service call replace fixture/photocell w/o commissioning Warranty replacement	$____	$350.00	$127.50	$315.00	$78.00	$535.00	25	$8,750.00	$3,187.50	$7,875.00	$1,950.00	$13,375.00
E1-30	Hourly Electrician labor rate with Bucket truck to install ancillary equipment (less than 15 lbs) on mast arm.	$____	$150.00	$107.50	$126.00	$155.00	$176.00	25	$3,750.00	$2,687.50	$3,150.00	$3,875.00	$4,400.00
E1-31	Complete installation 6 ft. mast arm with wiring and supplied LED fixture and Control device on existing utility pole with commissioning. (New Install where there is no light currently. Provide sufficient pigtail for EVERSOURCE to connect to secondary line.)	$____	$875.00	$428.00	$378.00	$391.00	$700.00	25	$21,875.00	$10,700.00	$9,450.00	$9,775.00	$17,500.00
E1-32	Complete installation 6 ft. mast arm with internal wiring and supplied LED fixture and Control device on existing utility pole w/o commissioning. New install where no light currently exists. Provide sufficient Pigtail on power side for EVERSOURCE to make connection to secondary.	$____	$800.00	$426.00	$378.00	$324.00	$575.00	30	$24,000.00	$12,780.00	$11,340.00	$9,720.00	$17,250.00
E1-33	Service call to replace failed photocell/control device with commissioning	$____	$275.00	$132.00	$250.00	$195.00	$550.00	25	$6,875.00	$3,300.00	$6,250.00	$4,875.00	$13,750.00
E1-34	Rewire fixture internally or change internal fixture setting		325		$0.00	$268.00	$535.00	25	$8,125.00	$0.00	$0.00	$6,700.00	$13,375.00
E1-35	Replace photocell receptacle with approved ANSI 136.41 seven pin receptacle. Includes providing receptacle.	$____	$275.00	$156.00	$279.00	$190.00	$550.00	25	$6,875.00	$3,900.00	$6,975.00	$4,750.00	$13,750.00
E1-36	Install 35 ft aluminum pole of a quality as good or better than the US NSTAR specifications on existing foundation (Assume foundation is serviceable) with six foot mast arm and 150 watt HPS cobra head cutoff fixture	$____ each	$3,500.00	$3,018.00	$3,040.00	$2,743.00	$4,000.00	25	$87,500.00	$75,450.00	$76,000.00	$68,575.00	$100,000.00
E1-37	Transfer existing mast arm with fixture from old pole to replacement pole in connection with utility company pole replacement.	$____ each	$480.00	$214.00	$315.00	$268.00	$450.00	300	$144,000.00	$64,200.00	$94,500.00	$80,400.00	$135,000.00
E1-38	Remove broken non utility wooden pole (assume approximately one to two feet of the old pole is left above ground as from a knockdown) and install new 35 foot wooden pole with standard six foot bracket and supplied LED fixture. Dispose of old pole.	$____ each	$2,300.00	$2,259.00	$1,752.00	$881.00	$3,800.00	25	$57,500.00	$56,475.00	$43,800.00	$22,025.00	$95,000.00
E1-39	Labor to rewire defective mast arm wires and reconnect light fixture. Complete cost for labor, travel and equipment. Wire to be billed based on per foot price next item below. Price for this line does not include wire price.	$____ each	$500.00	$284.00	$250.00	$194.00	$535.00	25	$12,500.00	$7,100.00	$6,250.00	$4,850.00	$13,375.00
E1-40	Replace defective mast arm wires with appropriately rated wiring for up to 250 watt fixtures. Price is wire only.	$____	$2.00	$1.77	$0.18	$7.00	$10.00	25	$50.00	$44.25	$4.50	$175.00	$250.00
E1-41	Install approved Fuse holder and Fuse in connection with service call.	$___N/A each	$80.00	$72.00	$7.50	$79.00	$100.00	25	$2,000.00	$1,800.00	$187.50	$1,975.00	$2,500.00
E1-42	Service call price-cost to respond to a service call and trouble shoot the light with no work required at the scene	$____	$260.00	$214.00	$250.00	$51.00	$535.00	85	$22,100.00	$18,190.00	$21,250.00	$4,335.00	$45,475.00
E1-43	<u>**Deduct**</u> for labor to install a fuse holder and fuse for any service call where the fuse is already installed	$___N/A	-$45.00	-$72.00	-$7.50	-$16.00	-$5.00		$0.00	$0.00	$0.00	$0.00	$0.00
E1-44	Standard Material Markup	%	10%	7%	15%	20%	25%		$0.00	$0.00	$0.00	$0.00	$0.00
A1-1	Change head without commissioning		$150.00	$79.75	$65.00	$86.74	$110.00	10000	$1,500,000.00	$797,500.00	$650,000.00	$867,400.00	$1,100,000.00
A1-2	Change head with commissioning		$180.00	$379.50		$106.26			$0.00	$0.00	$0.00	$0.00	$0.00
A1-3	HPS per month (I have assumed four months just to gauge impact not a bid item in the final tally)..		$1.20	$2.25	$1.53	$1.65	$2.90	1000	$1,200.00	$2,250.00	$1,530.00	$1,650.00	$2,900.00
D1A1	Emergency response		$260.00	$428.00	$252.00	$311.00	$535.00	36	$9,360.00	$15,408.00	$9,072.00	$11,196.00	$19,260.00
D1-A2	Emergency Response after hours		$375.00	$578.00	$800.00	$363.00	$675.00	36	$13,500.00	$20,808.00	$28,800.00	$13,068.00	$24,300.00
D1-A3	Emergency response Holiday rate								$0.00	$0.00	$0.00	$0.00	$0.00

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20697 ALJ Sally Wallace

PROOF OF SERVICE

On the date below, an electronic copy of **the REVISED PUBLIC Testimony and Exhibits MAU-14 and MAU-15 of Richard Bunch on behalf of Michigan Municipal Association of Utility Issues** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Hon. Sally Wallace	wallaces2@michigan.gov
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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MAUI

Date: June 26, 2020 By: ______________

Digitally signed by Kimberly Flynn
DN: cn=Kimberly Flynn, o=Olson Bzdok & Howard, P.C., ou, email=kimberly@envlaw.com, c=US
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Exhibit Bunch 9

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	))))))	Case No. U-20561 ALJ Sharon L. Feldman

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DIRECT TESTIMONY OF RICHARD BUNCH

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,
AND CITIZENS UTILITY BOARD OF MICHIGAN

November 6, 2019

TABLE OF CONTENTS

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Richard Bunch. I am a Senior Consultant of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra Club ("SC"), and the Citizens Utility Board of Michigan ("CUB").

Q. Please summarize your educational background.

A. I hold a Master of Business Administration degree with Environmental Management Certificate from University of Washington Business School, and a Bachelor's degree in Political Science from Yale University.

Q. Please summarize your professional development coursework in the field of electric utility regulation.

A. In June of 2019 I attended EUCI's Outdoor Street Lighting Conference: Best practices in streetlight design, strategy, deployment, and LEDs in Atlanta. In July of 2019 I attended EUCI's Electric Cost-of-Service - Essential Concepts for a Changing Industry Course in Chicago.

Q. Please summarize your experience in the field of electric utility regulation.

A. I have worked for more than five years in positions related to clean energy, primarily on behalf of local governments. A significant portion of that work has included analysis of MPSC rate and other cases and supporting local government participation in rate cases and other MPSC proceedings. My work experience is summarized in my resume, provided as Exhibit MEC-n (RJB-1).

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. No.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MEC, NRDC, SC, and CUB regarding electricity production cost allocation using the equivalent peaker method.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEC-n (RJB-1): Resume of Richard Bunch
- Exhibit MEC-n (RJB-2): Equivalent Peaker production cost allocation analysis
- Exhibit MEC-n (RJB-3): DTE Discovery response MECNRDCSCDE7.13-7.16, narrative and attachments (plant production costs).

<u>II. EQUIVALENT PEAKER PRODUCTION COST ALLOCATION</u>

Q. What is a peaker plant?

A. Peakers are power plants that generally run only when there is a high demand (peak demand) for electricity. Because utilities don't want to invest a lot of capital in assets that sit idle most of the time, peakers usually are plant types with low capital costs. They are less efficient, and consequently cost more to operate per unit of production than base-load plants, because it doesn't make sense to invest heavily in a lightly used resource. Most often, modern peakers are gas turbines that burn natural gas. DTE Energy also owns several internal combustion peakers.

Q. What is an "Equivalent Peaker"?

A. An Equivalent Peaker has the same effective capacity and in-service date as another capacity resource.

Q. How does Equivalent Peaker analysis inform production cost allocation?

A. The Equivalent Peaker method considers the demand-related portion of production plant to be the minimum cost of reliably meeting projected demand, and the remainder to be the energy-related portion.

If DTE Electric only needed additional reliability, and there were no need for additional energy or economic benefit from reducing use of fuel, DTE would add peaking capacity, such as a gas turbine. In practice, in addition to its fleet of peaking plants, DTE has often acquired significantly more expensive coal, nuclear, wind and solar plants to reduce fuel costs and satisfy customer preferences. Because the incurring of additional costs for those resources, compared to equivalent peakers, was motivated by energy-related objectives, those costs should be allocated to energy and not demand in the production allocation function.

Q. Is Equivalent Peaker a generally recognized method of production cost allocation?

A. Yes. The National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual discusses thirteen embedded cost allocation methods including Equivalent Peaker.[1] The NARUC manual also recognizes the tradeoff of capacity and energy in the choice of different kinds of electric capacity resources.[2]

Q. Is Equivalent Peaker an appropriate production allocation methodology to use in Michigan?

A. Yes. Wherever electricity demand is characterized by significant peaks relative to base load, and/or where base load is expected to remain relatively stable, the main reason for a utility to add capacity is to serve peaks in demand. This description fits Michigan well. In this situation, incurring generation plant costs higher than required for a peaker resource is justified only to keep energy costs down, and thus the incremental capital costs should be allocated to energy, not capacity.

Q. Did you make any adjustments to the standard Equivalent Peaker analysis of DTE's capacity resources?

A. Yes. DTE did not provide net book values for individual generating units, so I could not precisely determine the current cost of each unit.[3] Therefore, I implemented a modified Equivalent Peaker methodology that uses only verified data from DTE, more comprehensively and accurately assess all costs and generates findings of more direct relevance for rate setting purposes. While these limitations caused me to perform a

[1] National Association of Regulatory Utility Commissioners (NARUC), "Electric Utility Cost Allocation Manual", January 1992. PP.39-68.
[2] NARUC, ibid, p.53 and elsewhere.
[3] See Exhibit MEC-n(RJB-3), DTE discovery response MECNRDCSCDE7.16

modified analysis, DTE would be able to perform a standard Equivalent Peaker analysis with its better access to unit-level cost data.

Q. Please describe how your modified Equivalent Peaker methodology produces findings more relevant to rate setting.

A. I compared Equivalent Peaker revenue requirements to revenue requirements of DTE's actual generating fleet in the future test year. Equivalent Peaker analysis usually compares gross plant costs between peakers and contemporaneous actual capacity resources, without carrying that number through to determine how it affects the revenue requirements that are a central focus of rate making.

Q. How does how your modified Equivalent Peaker methodology assess costs more comprehensively and accurately?

A. By using a required revenue measure, I am better able to consider all capital costs, depreciation, and operating and maintenance costs.

Standard Equivalent Peaker analysis may not take into account capital investments subsequent to in-service date. If the equivalent peaker share of the original investment in a non-peaker generation unit is used to allocate the costs of that generating unit between equivalent peaker and energy costs, this omission may distort allocation of costs between capacity and energy; pollution control retrofits, for example, would be considered energy costs, which should reduce the overall percentage of plant costs allocated to capacity. Standard Equivalent Peaker analysis omits such costs.

Standard Equivalent Peaker analysis also does not usually directly capture depreciation.

Differing depreciation rates may change the ratio of Equivalent Peaker to, say, coal plant costs over time, such that comparing original investment costs offers a less and less accurate assessment of current costs. Many coal plants, for that matter, are now slated for early retirement and are subject to accelerated depreciation, which we can capture by using a required revenue measure rather than a measure pegged to original investment cost. In sum, by incorporating net book value of assets and current depreciation, a required revenue measure better captures how the full history of capital expenditures on a unit affect today's costs.

Finally, standard Equivalent Peaker analysis considers only capital investment costs, and by doing so may fail to consider differences in maintenance and operating costs between peakers and other kinds of generating resources. A cost measure based on required revenue, as I use, includes operating and maintenance costs.

Q. How were you able to perform Equivalent Peaker analysis using only data from DTE?

A. I found the overall *average* revenue requirement per MISO ("Midcontinent Independent System Operator") Zonal Resource Credit for DTE's peaker plants collectively. Similarly, I found the total average revenue requirement per MISO Zonal Resource Credit for each other category of capacity resource covered in the Cost of Service Study: Fossil, Nuclear, Hydraulic and Purchased Power. Standard Equivalent Peaker methodology, in contrast, would match contemporaneous peakers to each individual DTE generating unit, rather than averaging costs across categories of generation types. Given its better access to cost data for each of its generating units, DTE would be able to achieve matching of individual unit costs to equivalent peakers, per the standard approach, even retaining the required revenue modification I have used in order to more comprehensively analyze costs.

Q. Why did you use total revenue requirements by generation category, rather than the standard Equivalent Peaker method of using unit-specific costs?

A. My modified approach was somewhat necessitated because DTE provided net book value only by generating category (Fossil, Nuclear, Peakers, Hydraulic and Purchased Power), rather than for each generating unit. I could not precisely calculate revenue requirements per generating unit without knowing net book value per unit.

Although I was able to identify almost 100 peakers owned by investor-owned utilities in Michigan and neighboring states, comparing cost data for peakers owned by other utilities offered less equivalence to DTE resources, and in any event the unavailability of net book value data for individual generating units would have made one-to-one equivalent-peaker matching less accurate even had I attempted it.

Q. How did your use of total revenue requirements per generation category, rather than unit-specific revenue requirements, affect your findings?

A. My approach is conservative in the sense that it overstates the value of capacity, and understates the value of energy, in my final production cost allocation calculation. In other words, had data been available to match costs of every DTE capacity resource with contemporaneous peaker(s), I would have found a lower value of capacity in production allocation than I did.

This overstatement of the value of capacity occurs because the capacity-weighted average age of DTE's peakers is significantly less than that of its fossil, nuclear and hydro resources. DTE's peakers will have a capacity-weighted age of 26 years in 2020, while the combined capacity-weighted age of its fossil, nuclear and hydro units will be 44 years.[4] I did not include capacity-weighted age of DTE's PPAs in this calculation because I did not have in-service dates for the PPAs. Although the PPAs are much newer on average than DTE's other capacity resources, they comprise only about 1.7% of DTE's total ZRCs, thus omitting them from the ZRC-weighted unit age calculation makes very little difference.

Q. Does your modified Equivalent Peaker method reduce accuracy of your findings?

A. There are tradeoffs, but overall my modified approach is simpler, does not attempt to compare DTE costs to those of other utilities, and does not depend on any estimated data, all of which would be unavoidable if I performed standard Equivalent Peaker analysis with the data available to me. On the other hand, the modified approach relies on a data set of fewer peaker plants (only those owned by DTE) and does not match each capacity resource to a contemporaneous equivalent peaker. On balance, the modified Equivalent Peaker approach provides more credible equivalence to DTE's capacity resources than had I adhered strictly to standard Equivalent Peaker methodology.

Q. How did you determine the revenue requirements for each category of DTE capacity resource?

A. MEC witness Boothman provided revenue requirements by generation category.[5] I modified his Total Electric required revenue by subtracting Transmission, which is included in production cost allocation but has no associated Zonal Resource Credits.[6]

Q. Why did you use Zonal Resource Credits to measure capacity of DTE's capacity

[4] Exhibit MEC-n(RJB-2), p2.
[5] Exhibit MEC-n(KGB-2)
[6] Exhibit MEC-n(RJB-2).

resources?

A. ZRCs are the main capacity planning measure used by utilities in the MISO ("Midcontinent Independent System Operator") region. ZRCs measure the ability of a capacity resource to contribute to system demand during peak periods. Resources have varying abilities to respond to demand – for example, a gas turbine can increase output very quickly in response to demand, but a wind turbine cannot request the wind to blow any harder. ZRCs also account for the probability that a unit will experience a forced outage and be unavailable for generation at the time of peak demand. Thus, ZRCs are a much more accurate expression of a resource's ability to contribute to system demand than is its nameplate capacity.

Q. How did you determine ZRCs for DTE's various capacity resources?

A. ZRCs for each generating unit were provided by DTE.[7] I summed them within each category of generating resource (Fossil, Nuclear, Peaker, Hydraulic and Purchased Power) to find total ZRCs per category.[8] MISO energy purchases have no capacity value, and thus have no ZRCs associated with them.

Q. Why did you not include DTE-owned wind and solar capacity resources in your analysis?

A. DTE's wind and solar capacity resources are not included in the Cost of Service Study for this rate case. Rates for these resources, which are part of DTE's Renewable Energy Plan, are determined in DTE's Power Supply Cost Recovery cases. It would be wholly feasible

[7] DTE discovery responses 4.4ev-evii and 4.4fi-fii
[8] Exhibit MEC-n(RJB-2)

and appropriate to apply my Equivalent Peaker analysis to wind and solar resources as part of a PSCR case but doing so is beyond the scope of this rate case.

Q. How did you perform your modified Equivalent Peaker analysis?

A. First, I calculated the required revenue per ZRC for DTE's peaker plants. I found that the average peaker ZRC is associated with an annual revenue requirement of $96,230,00.[9]

Q. How did you find the capacity-related share of revenue requirement within each category of generation resource?

A. I multiplied the average peaker revenue requirement per ZRC times the total ZRCs in each category of generating resource (Fossil. Nuclear, Hydraulic, PPAs and Total Electric).[10] As noted above, MISO purchases have no capacity value. This product estimates the revenue requirement were the ZRCs in each category generated wholly by contemporaneous peakers. This number can be understood as the lowest cost DTE could have incurred to match the total effective energy capacity in each category of generation. It should be noted that this figure includes all of the corporate overhead, working capital, and other costs allocated to production cost of service and is therefore not directly comparable to such figures as cost of new entry.

Q. How did you determine the energy-related portion of revenue requirement for each category of generating resource?

A. I subtracted the equivalent peaker revenue requirement from MEC witness Boothman's projected revenue requirement for each category. (In the case of MISO purchases, there is

[9] Exhibit MEC-n(RJB-2).
[10] Exhibit MEC-n(RJB-2)

no capacity credit, or ZRCs, so 100% of MISO purchase cost is allocated to energy.) The difference determined by this calculation estimates energy-related revenue requirement for each resource category. In other words, it is cost caused by efforts to reduce the cost of energy production or satisfy customer energy preferences, not cost related to increasing capacity of the resource.

Q. According to your Equivalent Peaker analysis, how much of DTE's total electric revenue requirement for 2020 is capacity related?

A. Less than 32.3%, or $948,328,000, of DTE's total revenue requirement of $2,393,675,000 for electric generation is capacity related.[11]

Q. According to your Equivalent Peaker analysis, how much of DTE's total electric revenue requirement is energy related?

A. More than 67.7%, or $1,991,347,000, of DTE's total revenue requirement for electric generation is energy related.[12]

Q. Why do you qualify your findings with "less than" and "more than"?

A. Because my calculations are conservative: the true value of capacity is even lower. As noted above, because DTE's peakers are significantly younger than its fossil, nuclear and hydro resources (when capacity-weighted), averaging costs across categories overvalues

[11] Exhibit MEC-n(RJB-2)
[12] Exhibit MEC-n(RJB-2)

energy in the modified methodology I employed.

IV. RECOMMENDATIONS AND CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. On behalf of MEC, NRDC, SC, and CUB, I recommend that:

1. The Commission require DTE Electric to file an Equivalent Peaker production allocation methodology in its next rate case, based on per plant revenue requirements for each of DTE Electric's peakers and other resources, and appropriate age-adjusted equivalent peaker revenue requirement for non-peaker resources.

Q. Does that complete your testimony?

A. Yes.

Exhibit Bunch 10

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **DTE ELECTRIC COMPANY** for approval of depreciation accrual rates and other related matters.	))))	Case No. U-18150

At the December 6, 2018 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

On November 1, 2016, following the filing of a motion for extension of time, DTE Electric Company (DTE Electric) filed its application, with supporting testimony and exhibits, in this case, pursuant to the June 16, 2011 order in Case No. U-16117 and the July 8, 2014 order in Case No. U-16991. DTE Electric's application in this case sought authority to revise its depreciation practices and rates, resulting in a proposed increase of $156 million to the company's annual depreciation expense.

A prehearing conference was held on January 10, 2017, before Administrative Law Judge Sharon L. Feldman (ALJ). DTE Electric and the Commission Staff (Staff) participated in the proceeding. On May 15, 2017, the ALJ granted intervenor status to the Association of Businesses Advocating Tariff Equity (ABATE).

An evidentiary hearing was conducted on October 24, 2017. The parties filed initial briefs on December 1, 2017, and ABATE and DTE Electric filed reply briefs on December 21, 2017. The ALJ issued a Proposal for Decision (PFD) on April 17, 2018. ABATE and DTE Electric respectively filed exceptions on May 4 and 8, 2018, and replies to exceptions were filed by the Staff and DTE Electric on May 22, 2018. On November 30, 2018, the parties filed a settlement agreement resolving all issues in the case.

According to the terms and conditions of the settlement agreement, attached as Exhibit A, the parties agree that it is reasonable and in the public interest to increase DTE Electric's depreciation rates, and associated depreciation expense, based on depreciation rates designed by the company to accomplish an approximate $90 million depreciation expense increase, along with various other depreciation-related accounting, policies, and ratemaking. Settlement Agreement, pp. 2-3. The parties further agree to the depreciation rates, terms, and conditions of the settlement agreement being implemented and becoming effective upon the effective date of new retail electric rates pursuant to a final order in DTE Electric's general rate case, Case No. U-20162, and for the company to be required to file a new depreciation case no later than December of 2024 based on plant balances as of December 31, 2023. *Id*., p. 3.

The Commission has reviewed the settlement agreement and finds that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission further finds that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Exhibit A, is approved.

B. DTE Electric Company is authorized to increase its depreciation rates, and associated depreciation expense, based on depreciation rates designed by the company to accomplish an approximate $90 million depreciation expense increase effective upon the effective date of new retail electric rates pursuant to a final order in DTE Electric Company's general rate case, Case No. U-20162.

C. The various other depreciation-related accounting, policies, and ratemaking set forth in the settlement agreement are approved.

D. DTE Electric Company shall file a new depreciation case no later than December of 2024 based on plant balances as of December 31, 2023.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General – Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of December 6, 2018.

Kavita Kale, Executive Secretary

EXHIBIT A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of depreciation accrual rates and other related matters	))))	Case No. U-18150

STIPULATION AND SETTLEMENT AGREEMENT

Pursuant to Section 78 of the Administrative Procedures Act of 1969 ("APA"), as amended, MCL 24.278 and Rule 333 of the Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or "Commission"), the undersigned parties agree as follows:

1. This Stipulation and Settlement Agreement ("Settlement Agreement") between and among DTE Electric Company ("DTE Electric"), the Michigan Public Service Commission Staff ("Staff"), the Association of Businesses Advocating Tariff Equity ("ABATE") (collectively, the "Parties") is intended by the Parties as a final settlement and satisfaction of all issues before the Commission related to DTE Electric's depreciation case filed in Case No. U-18150.

2. The Commission has reviewed and approved DTE Electric's depreciation procedures applicable generally to electric utility plant. DTE Electric is currently accruing depreciation for electric utility plant at rates and according to methods approved in the Commission's June 16, 2011 Order in Case No. U-16117 (the "U-16117 Order") and for renewable energy facilities such as wind and solar generation production facilities in the Commission's July 8, 2014 Order in Case No. U-16991 (the "U-16991 Order").

3. On November 1, 2016, DTE Electric filed an application, with supporting testimony and exhibits, pursuant to the U-16991 and U-16117 Orders which instructed the Company to file this full depreciation case (including an update of rates for wind and solar assets) along with certain additional information which the Parties agree was fully and properly accomplished.

4. DTE Electric published notice of hearing in DTE Electric's electric service territory consistent with instructions from the Commission's Executive Secretary. (1T 3) A prehearing conference was conducted on January 10, 2017. (1T 1-6) DTE Electric, Staff and ABATE are Parties to the proceeding. (1T 1-6; Ruling Granting Intervention of ABATE dated May 5, 2017) The Parties filed Direct Testimony and associated Exhibits consistent with the case schedule. DTE Electric and ABATE filed Rebuttal Testimony and Exhibits. An evidentiary hearing was held on October 24, 2017 at which all testimony and exhibits were bound into the record by agreement of the Parties. (2T 7-215) Briefs and Reply Briefs were filed by the Parties and a Proposal for Decision was issued by the presiding Administrative Law Judge on April 17, 2018. Thereafter, DTE Electric and ABATE filed timely Exceptions and DTE Electric and Staff filed timely Replies to Exceptions. To efficiently resolve the matter, the Parties have agreed to enter into a full settlement of this case and recommend approval by the Commission of the terms and conditions in the paragraphs that follow.

5. The Parties request that the Commission enter an order (i) increasing DTE Electric depreciation rates and associated depreciation expense by a total of approximately $90 million based on depreciation rates designed by DTE Electric to accomplish the $90 million depreciation expense increase[1], see Attachment A, (ii) requiring DTE Electric Tier 2 power plants (ie. Trenton Channel, St. Clair and River Rouge) (hereinafter the "Tier 2 Plants") to maintain specific, non-group, individual power plant accounts for remaining investment and depreciation purposes, (iii) maintaining existing depreciation rates from the U-16117 Order for DTE Electric's Tier 2 plants, (iv) requiring future removal costs for the Tier 2 Plants, when the removal costs are incurred, to

[1] Final depreciation rates will be calculated by DTE Electric reviewed by Staff and ABATE and filed with the Commission after this Settlement agreement is approved by the Commission. The $90 million depreciation expense amount is based on the plant balances reflected in the Company's application in this proceeding, depreciation expense based on rates established pursuant to this settlement and applied to plant balance reflected in Case No. U-20162 will likely be higher than $90 million.

be reconciled after firm removal cost bids are accepted and reviewed by Staff and ABATE, (v) deferring inclusion in depreciation rates of removal costs for DTE Electric's Conner's Creek and Harbor Beach power plants until removal costs are actually incurred, (vi) authorizing amortization in lieu of depreciation for General Plant Account 397 Communication Equipment, (vii) authorizing the MERC depreciation rate of 4.05%[2], (vii) concluding that DTE Electric has complied with all requirements of the U-16117 Order and the U-16991 Order, (ix) approving the effectiveness of the depreciation rates, terms and conditions of an order approving this Settlement Agreement upon the effective date new retail electric rates pursuant to a final order in DTE Electric's general rate case, Case No. U-20162, and (x) approving a requirement for DTE Electric to file a new depreciation case no later than December of 2024 based on plant balances as of December 31, 2023.

6. In light of the proposed depreciation rates reflected in this Settlement Agreement and the associated delay in recovery of plant costs associated with DTE Electric's Tier 2 coal plants, the Parties also agree that expenditures and removal costs associated with DTE Electric's Tier 2 coal plants continue to be recoverable from traditional depreciation or other forms of recovery. DTE Electric agrees to seek recovery of the remaining net book value associated with its Tier 2 coal plants through securitization after the Tier 2 coal plants are retired if this is the lowest cost option for ratepayers. Other options to be evaluated include traditional depreciation, regulatory asset amortization in base rates, or other forms of ratemaking or regulatory relief.

7. This Settlement Agreement is entered into for the sole and express purpose of reaching a compromise among the Parties. All offers of settlement and discussions relating to this Settlement Agreement are considered privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the Parties to this settlement nor the

[2] Based on the 2015 MERC plant balance this results in an increase of $1.0 million (4.05%-2.81%) multiplied by $84,408,903.

Commission shall make any reference to, or use this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding except as set forth herein with respect to Case No. U-20162; provided however, such references may be made to enforce or implement the terms of the Settlement Agreement and the order approving it. Except with respect to and in this Case No. U-18150 and Case No. U-20162, this Settlement Agreement does not limit any Party's right to take new and/or different positions on similar issues in other administrative proceedings or related appeals. No party shall appeal a Commission order approving or implementing this Settlement Agreement without modification.

8. This Settlement Agreement specifically does not address the regulatory treatment of obsolete inventory of Tier 1 power plants.

9. This Settlement Agreement is not severable. Each provision of this Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, and shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall not operate to prejudice the pre-negotiation positions of any party.

10. This Settlement Agreement is reasonable and in the public interest, and will reduce the time and expense of the Commission, its Staff, and the Parties.

11. The Parties agree to waive Section 81 of 1969 PA 306 (MCL 24.281), as it applies to the issues in this proceeding, if the Commission approves this Settlement Agreement without modification.

12. This Settlement Agreement may be executed in any number of counterparts, each considered an original, and all counterparts that are executed shall have the same effect as if they were the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Settlement Agreement to be duly executed by their respective duly authorized officers as of the date first written below.

DTE ELECTRIC COMPANY

By: Jon P. Christinidis Digitally signed by Jon P. Christinidis Date: 2018.11.30 12:00:48 -05'00' Dated: November 30, 2018

Jon P. Christinidis

Its: Attorney

Jon P. Christinidis (P47352)
(313) 235-7706

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Heather Durian Digitally signed by Heather Durian Date: 2018.11.30 12:32:07 -05'00' Dated:__________________, 2018

Heather Durian

Its: Attorney

Heather Durian (P67587)
Assistant Attorney General
(517) 284-8140

ABATE

By: Robert A. W. Strong Digitally signed by: Robert A. W. Strong DN: CN = Robert A. W. Strong email = rstrong@clarkhill.com C = US O = Clark Hill PLC Date: 2018.11.30 12:13:18 -05'00' Dated: Nov. 30 ____, 2018

Robert A.W. Strong

Its: Attorney

Robert A.W. Strong (P27724)
(248) 988-5861

rstrong@clarkhill.com

Attachment A
Case No. U-18150
Settlement Analysis

(000's)	Plant/Reserve Change	Remaining Life	Net Removal Change	Total
Steam Production	12,653	35,570	25,378	73,601
Tier 1 ($M)	*13*	*35*	*25*	*73*
Tier 2 ($M)	-	-	-	-
Nuclear	(1,136)	7,595	(4,553)	1,906
Other production	(3,057)	(7,004)	(1,864)	(11,925)
Renewables	(3,071)	2,963		(108)
Transmission	74	525		599
Distribution	(3,651)	22,450	(4,184)	14,615
General Plant Note (1)	12,353	(1,084)		11,269
Total	14,165	61,015	14,777	89,957

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-18150

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on December 6, 2018, 2018 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 6th day of December 2018.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-18150

Name	Email Address
Andrea E. Hayden	haydena@dteenergy.com
DTE Energy Company	mpscfilings@dteenergy.com
Heather M.S. Durian	durianh@michigan.gov
Jon P. Christinidis	jon.christinidis@dteenergy.com
Michael J. Pattwell	mpattwell@clarkhill.com
Monica M. Stephens	stephensm11@michigan.gov
Sean P. Gallagher	sgallagher@clarkhill.com
Sharon Feldman	feldmans@michigan.gov
Stephen A. Campbell	scampbell@clarkhill.com

Exhibit Bunch 11

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE Electric Company for approval of depreciation accrual rates and other related matters.	))))	Case No. U-18150

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on April 17, 2018.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before May 8, 2018, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before May 22, 2018.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by Sharon L. Feldman
DN: cn=Sharon L. Feldman, o=MAHS, ou=MAHS PSC, email=feldmans@michigan.gov, c=US
Date: 2018.04.17 14:45:47 -04'00'

Sharon L. Feldman
Administrative Law Judge

April 17, 2018
Lansing, Michigan

STATE OF MICHIGAN

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE Electric Company for approval of depreciation accrual rates and other related matters.	))))	Case No. U-18150

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On November 1, 2016, DTE Electric Company (DTE) filed application to revise its depreciation rates. DTE Electric's application was accompanied by the testimony and exhibits of seven witnesses: Ronald E. White, Howard R. Cooper, Paul G. Horgan, Edward T. Henderson, Kenneth D. Johnston, Neil E. Mortenson, and Robert P. Charles. In its application, DTE represents that it has complied with the Commission's directions in the two immediately prior depreciation cases, Case Nos. U-16117 and U-16991. The application requests approval of depreciation rates with a composite average of 4.09%, an increase over the composite average of 3.21% approved in Case Nos. U-16117 and U-16991.

At the January 10, 2017, prehearing conference, DTE and Staff appeared, and a consensus schedule was established. Subsequently, on May 15, 2017, DTE, Staff, and the Association of Businesses Advocating Tariff Equity (ABATE) filed a stipulation agreeing to the late intervention of ABATE. On that date, the ALJ issued a ruling granting the intervention, with the proviso that ABATE agreed to accept the existing schedule. The parties subsequently agreed to a revised schedule. Following that schedule, on August 15, 2017, ABATE filed the testimony of Brian C. Andrews, and Staff filed the testimony of Ronald J. Ancona. Also following that schedule, on September 18, 2017, DTE Electric filed the rebuttal testimony of Kevin Chreston, Dr. White, and Mr. Cooper, while ABATE filed the rebuttal testimony of Mr. Andrews.

At the October 24, 2017, evidentiary hearing, the testimony of all witnesses was bound into the record by agreement of the parties, without the need for the witnesses to appear, and all proffered exhibits were admitted into evidence. All parties filed briefs on December 1, 2017, and DTE and ABATE filed reply briefs on December 21, 2017.

II.

OVERVIEW OF THE RECORD

The evidentiary record is contained in 215 transcript pages in two volumes and 22 exhibits.[1] This section reviews the evidentiary record, beginning with the direct presentations of each party, then turning to the rebuttal testimony.

A. DTE Electric

Mr. Cooper is an Accounting Expert in the Asset Management department of DTE Energy Corporate Services, LLC.[2] He provided an overview of the company's filing and requested relief and identified the nature of the testimony of each of the

[1] Transcript references to the testimony contained in this PFD are to volume 2 unless otherwise specified. The exhibits are Exhibits A-1 through A-17, AB-1 through AB-4, and S-1.
[2] Mr. Cooper's educational background includes a bachelor's degree in Business Administration; he began working with Michigan Consolidated Gas Company in 1989. Mr. Cooper's qualifications are set forth at Tr 141-142; his testimony, including his rebuttal testimony, is transcribed at Tr 140-170.

company's witnesses. He explained that Dr. White of Foster Associates Consultants, LLC performed the depreciation study, while Mr. Charles of Sargent & Lundy, L.L.C. performed demolition studies for the net salvage calculations.

Mr. Cooper reviewed the Commission's directions in the company's most recent two depreciation cases, Case Nos. U-16117 and U-16991. He addressed the Commission's direction that the company provide 40 years of data in its next depreciation case for certain accounts,[3] including Accounts 352 (Transmission Structures and Improvements), 361 (Distribution Structures and Improvements), 390 (General Structures and Improvements), 366 (Distribution Underground Conduit), 367 (Underground Connectors and Devices), 368 (Line Transformers), 369 (Services—Overhead), and 370 (Meters). After explaining a distinction between "vintage year," which he defined as "the calendar year in which an item of plant or equipment is placed in-service," and "activity year," which he defined as "the calendar year in which a retirement, transfer, or adjustment is posted to the plant or reserve ledger,"[4] Mr. Cooper testified that DTE lost all "activity year" data prior to 1996 for these accounts. He testified that in accordance with R 460.2507, DTE notified the Commission of this missing data on December 9, 2014. He explained that because DTE does not have the retirement history for these accounts, its depreciation case uses the broad group

[3] In Case No. U-16117, DTE sought to switch depreciation methods for these accounts from a "broad group" straight-line, remaining-life depreciation system to a "vintage group" procedure. The Commission's June 16, 2011 order in that docket states as follows at page 12: "[I]n its next depreciation case Detroit Edison shall file 40 activity years data for the vintage group procedure." Ordering paragraph D at page 15 of the order states: "The Detroit Edison Company shall provide at least 40 vintage years of data when filing its next depreciation case" for these accounts.
[4] See Tr 148-149.

procedure for these accounts instead of the vintage year procedure, to conform to what the company believes was the Commission's intention Case No. U-16117.[5]

Mr. Cooper next addressed the Commission's direction in Case No. U-16991 that it provide a more detailed analysis of the assumptions underlying its choice of survivor curves for wind generating plant. He testified that the company has limited asset history for this plant and "believes use of estimated data for wind generating plant survivor curves is still appropriate."[6] Mr. Cooper identified a new cost category for which depreciation rates had not previously been set (Account 363, Storage Battery Equipment), and requested approval of sub-accounts for streetlighting types.

Mr. Cooper also testified that the removal cost estimates underlying the company's depreciation case include two cost categories not previously included in the analysis, "decontamination" and "decommissioning", which occur before "demolition." Further explaining the removal cost estimate, Mr. Cooper testified that at Mr. Horgan's instruction, he included $23.3 million in projected direct company labor and benefit expenses associated with a newly-formed internal team, the Major Enterprise Projects team, but excluded other direct company labor and benefit expenses totaling $47.7 million, and he excluded contingency cost estimates of $122.6 million.[7]

Mr. Cooper also addressed removal costs for Harbor Beach, which was retired in 2013, and for Conner's Creek, which was retired in 2011. He testified that the actual depreciation reserve balance for the test period ending December 31, 2015, included removal costs, but as shown in Exhibit A-6, DTE expects to incur additional removal costs of $12.2 million for Harbor Beach and $28.1 million for Conner's Creek between

[5] See Tr 149.
[6] See Tr 149.
[7] See Tr 151-152.

2018 and 2020. He testified that he directed Dr. White to include these estimated costs with the removal costs for the Rouge River plant, which is scheduled for retirement in 2020.[8] Specifically for Harbor Beach, Mr. Cooper testified that the additional $12.2 million removal cost projection was not included in the estimate prepared by Sargent & Lundy because at the time of that study, DTE planned to sell Harbor Beach, but has not finalized those plans.[9]

Mr. Cooper also provided testimony in support of the composite inflation rates used in projecting future removal costs, presenting the historical indices in his Exhibit A-2, and the projected values for 2016 through 2040 in his Exhibit A-3.[10] He testified that he instructed Dr. White to include removal costs inflated to five years after the retirement date for each plant, recognizing that the removal cost study performed by Sargent & Lundy and explained by Mr. Charles estimated removal costs in 2016 dollars.[11] Mr. Cooper testified that he also instructed Dr. White to include $61.8 million in "obsolete inventory" costs in his depreciation expense calculations, which Mr. Cooper testified are supported by his Exhibit A-4.[12] Mr. Cooper also addressed the "interim" removal cost estimates for Fermi 2.[13]

Mr. Cooper sought permission from the Commission to amortize costs in Account 397, Communications Equipment In General Plant, testifying that it is difficult to track and consistently report retirements for this account, showing the account balance in his Exhibit A-5.[14] He also asked to combine the balances in Account 370.01 (Conventional

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[8] See Tr 152-153.
[9] See Tr 151-152.
[10] See Tr 153-154.
[11] See Tr 154.
[12] See Tr 152.
[13] See Tr 154.
[14] See Tr 154-155.

Meters) and Account 370.02 (AMI Meters), on the basis that conventional meters are being phased out and will no longer be in service by the end of 2017.[15] Mr. Cooper presented the company's requested depreciation rates in his Exhibit A-7, asserting that these rates will provide DTE the necessary cash flow to operate and maintain its business and appropriately reflect the consumption of the assets over their average remaining life.[16] He also presented depreciation rates for MERC in his Exhibit A-11, explaining that the increase in depreciation rate from the 2.81% approved in Case No. U-10348 and the 4.05% rate requested in this case is due to the land lease expiring in 10 years.[17]

Mr. Charles is a Senior Principal Consultant with Sargent & Lundy, L.L.C.[18] As noted above, his firm performed the removal cost studies underlying the company's depreciation case, which are included in Exhibit A-14. He testified that the studies include a cost estimate and environmental review for the dismantlement and scrap of certain coal-fired sites, gas-fired sites, diesel-fired peakers, wind farms, solar arrays, and landfill sites. He explained the general methods, "stochastic" and "deterministic," that were used in the study, along with the decommissioning and decontamination cost information supplied by DTE. He testified that his staff visited several sites, including a wind farm and two solar sites. He also testified that no salvage value was assumed for any equipment, only the scrap value of metal from the equipment.[19] He presented a table summarizing the estimated removal costs by plant or plant type. He testified that

[15] See Tr 155.
[16] See Tr 156.
[17] See Tr 156.
[18] Mr. Charles's educational background includes a bachelor's degree in electrical engineering, and he is a registered professional engineer in Illinois and Pennsylvania. His testimony is transcribed at Tr 14-28.
[19] See Tr 21.

the estimated costs include contingency amounts, and that the sites were presumed to be returned to an "improved industrial site" level. He also identified specific instructions the Commission provided in Case No. U-16991 and indicated that his study complied with these instructions.[20]

Mr. Henderson works for DTE as Manager of Renewable Energy Operations within the Business Planning & Development department.[21] He testified to provide an overview of the wind and solar projects included in the company's depreciation case, and to address certain instructions the Commission gave in Case No. U-16991. His testimony included a chart identifying each of the company's wind and solar facilities at the time of the depreciation study, by size, year in service, and nature of DTE's interest in the underlying property. Specifically addressing the Commission's direction to assess the potential to reuse wind towers with future generators, he acknowledged that General Electric has a new program to extend the useful life of wind turbine generators, and he acknowledged that manufacturers are contemplating measures such as stiffening rings to extend the lives of towers, but further testified that DTE has not performed an analysis of the viability of the towers and foundations to accommodate such extensions, and therefore assumes that the turbines will be dismantled when the wind parks are decommissioned.[22] He also testified that there have been no significant changes in disposal alternatives for solar panels, although many experts believe

[20] See Tr 27-28.
[21] Mr. Henderson's educational background includes a bachelor's degree in mechanical engineering. He is a registered professional engineer in Michigan and has worked for DTE Electric since 1981. His testimony is transcribed at Tr 45-56.
[22] See Tr 54-55.

alternatives will develop.[23] He also testified that DTE has not included interim retirements for solar and wind projects due to its limited history with these assets.

Mr. Horgan is Director of Regulatory Operations for DTE Energy Corporate Services, LLC.[24] He testified in support of two adjustments he directed Mr. Cooper to make to the demolition study prepared by Sargent & Lundy. As noted above, DTE excluded $122.6 million in contingency amounts from the cost estimates, and $48.1 million in direct company labor and benefits over and above the MEP team cost estimate. He stated that the rationale for excluding contingency costs is to mitigate the proposed depreciation rate/expense increase to customers, recognizing that the costs will not be incurred for at least 7 years.[25] He also recommended that direct labor costs over and above the MEP team costs be revisited closer to the decommissioning.[26] Mr. Horgan also stated the company's request that the Commission retain the most-recently-approved depreciation rates through the self-implementation period of the company's current rate case.

Mr. Johnston is Manager of Community Lighting for DTE.[27] He testified regarding the company's streetlighting assets. He requested that the accounts for the streetlight assets be revised, with the creation of eight additional subaccounts to separate lighting technologies into two groups: high-intensity discharge, which includes mercury vapor, high pressure sodium, and metal halide; and light-emitting diode (LED) technology. Each of these technology groups would have separate accounts depending

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[23] See Tr 55-56.
[24] Mr. Horgan's educational background includes an undergraduate degree in accounting as well as an MBA. He worked for ANR Pipeline Company for over 20 years before beginning work with DTE Energy in 2001. His testimony is transcribed at Tr 58-66.
[25] See Tr 64.
[26] See Tr 64-65.
[27] Mr. Johnston's educational background includes a bachelor's degree in engineering and an MBA degree. He has worked for DTE Electric since 1985. His testimony is transcribed at Tr 68-89.

on whether the lighting is fed by overhead or underground wires, and the remaining four new subaccounts are for related equipment and wires. He explained the allocation of costs in existing subaccounts to the new subaccounts, presenting Exhibits A-8 and A-9. He also reviewed the company's lighting tariffs, including DTE's determination of contributions in aid of construction, and averred that customer contributions in aid of construction are not included in the capital balances for these assets.[28] He also recommended a reduction in the useful life of mercury vapor assets to 10 years, given the anticipated conversion of these assets to LED lighting within that timeframe.[29]

Mr. Mortensen is employed by DTE Energy Corporate Services, LLC as Construction Project Manager for the Major Enterprise Projects team.[30] He testified to describe the decommissioning, decontamination and disposition of the Marysville Power Plant, which was sold in 2014, and the expected disposition of Harbor Beach Power Plant. He testified that DTE sold the Marysville plant and property in 2014 for $0.5 million, but as shown in Exhibit A-10, the Major Enterprise Projects team estimates that the demolition cost was $31.9 million as shown in Exhibit A-10, with scrap value of $9.7 million. He presented Exhibit A-12 to compare the sale of Marysville to the sale of Harbor Beach, and he testified that Harbor Beach and Marysville are not representative of the costs of demolition for DTE's remaining power plants.[31] His Exhibit A-13 shows his estimated total demolition costs for Harbor Beach of $12.2 million.

[28] See Tr 84.
[29] See Tr 89.
[30] Mr. Mortensen's educational background includes a bachelor's degree in construction management and a master's degree in organizational management; he worked for several companies before joining DTE Energy in 2002. His testimony is transcribed at Tr 91-97.
[31] See Tr 95-97.

Dr. White is President of Foster Associates Consultants, LLC.[32] As noted above, he performed the depreciation study underlying DTE's application in this case, Exhibit A-15. He described the principal steps he undertook, including data collection, the analysis of past retirement experience to estimate service life, the projection of future life curves, the estimation of a net salvage rate, an analysis of the adequacy of the depreciation reserve, and proposed redistribution of the recorded reserve. He testified that he used data from 2009 through December 31, 2015, taken from the company's Continuing Property Record maintained in a software program called PowerPlan, and appended this data to the database used in the 2009 depreciation study, which itself came from two different sources.[33] Discussing net salvage rates, Dr. White testified that he relied on historical data, and incorporated the results of the Sargent & Lundy demolition study for certain plants, with the modifications discussed by Mr. Cooper.[34]

Dr. White also evaluated the recorded depreciation reserve relative to the theoretical depreciation reserve. Citing Statement C of Exhibit A-15, he testified that as of December 31, 2015, recorded reserves were 38.2% of depreciable plant, while the corresponding "computed reserve" or theoretical reserve is 40.5% of depreciable plant investment. He computed the annual expense derived by amortizing the difference ($410,160,454) over the composite weighted-average remaining service life using the rates determined in his study.[35] He also recommended "rebalancing" the existing depreciation reserves for each primary account "to reduce offsetting imbalances and

[32] Dr. White's educational background includes a bachelor's degree in engineering operations, and a master's degree and Ph.D. in engineering valuation. His qualifications are set forth in more detail in the resume attached to his testimony at Tr 113-126. His direct and rebuttal testimony is transcribed at Tr 99-137.
[33] See Tr 106.
[34] See Tr 107-108.
[35] See Tr 108-109.

increase depreciation rate stability."[36] He presented the adjustments in Statement D of Exhibit A-15.

Dr. White summarized the results of his analysis, based on the instructions provided by DTE and the demolition studies performed by Sargent & Lundy, as requiring a $156,384,755 increase in annual depreciation expense, including $39,218,444 attributable to the amortization of the reserve imbalance, and an increase in the composite depreciation rate from 3.21% to 4.09%.[37]

B. Staff

Mr. Ancona is Manager of the Act 304 and Sales Forecasting Section in the Regulated Energy Division of the MPSC.[38] On behalf of Staff, he recommended that the Commission limit the increase in depreciation expense to the portion attributable to the amortization of the reserve imbalance determined by Dr. White. Mr. Ancona testified to Staff concerns with the retirement dates assumed for St. Clair, River Rouge, and Trenton Channel, with DTE's assumption that demolition costs would not be incurred until five years after retirement, and with the inclusion of obsolete inventory amounts for plants not yet retired.[39] Mr. Ancona presented Exhibit S-1 to show that DTE's depreciation reserve has not been keeping pace with plant in service over the last ten years. On this basis, he concluded an increase in the depreciation reserve is reasonable. He recommended against a further increase in view of Staff's concerns with the service life and demolition cost analysis.

[36] See Tr 109.
[37] See Tr 112.
[38] Mr. Ancona's educational background includes a bachelor's degree in geology and master's degree in resource development; his qualifications are further set forth at Tr 207-211. His testimony is transcribed at Tr 206-213.
[39] See Tr 212.

C. ABATE

Mr. Andrews is a Consultant with the firm Brubaker & Associates, Inc.[40] On behalf of ABATE, he raised several objections to the proposed depreciation rates and depreciation expense requested by DTE. After reviewing the principles of depreciation and the methods used in DTE's study, Mr. Andrews testified that DTE's proposal is a 27% increase in depreciation expense, with $114 million attributed to recovery of investment and $35 million attributed to increased removal costs. Mr. Andrews first objected to DTE's reduction to the retirement dates for several of its coal plants, on the basis that DTE had not supported the revised dates, and that they are significantly earlier than approved in Case No. U-16117. He attributed $88 million of the annual expense increase to the change in retirement dates.[41] He recommended that the Commission await review of the company's integrated resource plan (IRP) before adopting the revised service lives. He also recommended that the Commission consider whether DTE should seek to securitize unrecovered plant balances at the time of final retirement.[42]

Second, Mr. Andrews objected to the decommissioning cost estimates used in the company's analysis, testifying that the costs are escalated too far into the future, and that land values and the time value of money are not adequately considered.[43] Third, he objected to DTE's proposal to recover estimated decommissioning costs for Conner's Creek and Harbor Beach through the depreciation rates for the River Rouge

[40] Mr. Andrews' educational background includes a bachelor's degree in electrical engineering and a master's degree in applied economics; his qualifications are further set forth in Appendix A to his testimony at Tr 196-197. Mr. Andrews' testimony, including his rebuttal testimony, is transcribed at Tr 173-204.
[41] See Tr 179, 181-184.
[42] See Tr 193.
[43] See Tr 185-187, 190-193.

plant, characterizing it as inappropriate.[44] Fourth, he objected to DTE's proposal to recover "obsolete inventory" for plants that have not yet been retired, characterizing this as improper and beyond what the Commission authorized in Case No. U-18033.[45] Based on his objections, he calculated a reduction of $101 million in DTE Electric's requested depreciation expense level.

D. Rebuttal

In his rebuttal testimony, Mr. Cooper addressed Staff and ABATE witness objections to the company's designation of obsolete inventory costs. He reviewed the Commission's May 20, 2016, accounting order in Case No. U-18033 (May 2016 Order) and provided his opinion that DTE's requested recovery of obsolete inventory costs in this case is consistent with that order.[46] He also cited a discovery response to ABATE, which he provided in Exhibit A-16, to support his testimony that DTE "thoroughly supported" the level of obsolete inventory its requesting to recover through this proceeding.[47]

Addressing DTE's decommissioning cost estimates, Mr. Cooper disputed Mr. Andrews' testimony regarding the treatment of the value of land, characterizing his recommendation as inconsistent with the established accounting for land. He disputed Mr. Andrews' testimony that the time value of money should be reflected in the calculations, characterizing that approach as inconsistent with the approved depreciation methodology and citing the Commission's orders in Case Nos. U-15629

[44] See Tr 189.
[45] See Tr 187-188.
[46] See Tr 159-161.
[47] See Tr 160.

and U-16117.[48] He also disagreed with Mr. Andrews and Mr. Ancona regarding DTE's escalation of decommissioning costs to a date five years past each plant's proposed retirement date.[49] He testified that 25% of the work may be done prior to or within the first year after a unit retirement, but 75% of the work, the demolition phase, may take an additional three years, with site restoration taking an additional one to two years "to satisfy the requirements of the Michigan Department of Environmental Quality and receive a "No Further Action" (NFA) letter.[50] He cited as an example the Marysville plant implosion in November of 2015, testifying that the company that acquired the facility still has not received an NFA letter.

Mr. Chreston is the Manager of IRP & Modeling for DTE.[51] He provided rebuttal testimony to address DTE's choice of retirement dates for its coal plants, in response to Mr. Ancona's and Mr. Andrews' testimony. He testified that Exhibit AB-1, a DTE data response, does provide an economic analysis supporting the new proposed retirement dates. He also disputed Mr. Andrews' testimony that the retirement dates are largely based on the implementation of the federal Clean Power Plan, citing other environmental obligations as well. He discussed DTE's "integrated resource planning principles," and testified that the company's integrated resource plan (IRP) has been filed as part of its application for a certificate of necessity to build a new gas-fired plant in Case No. U-18419.[52] He subsequently reviewed the method of analysis the company used, and presented the base case results along with the results of alternative

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[48] See Tr 162-163, 168-169.
[49] See Tr 165-168.
[50] See Tr 167.
[51] Mr. Chreston's educational background includes a bachelor's degree in mechanical engineering; his qualifications are set forth in more detail at Tr 31-34. Mr. Chreston's rebuttal testimony is transcribed at Tr 30-42.
[52] See Tr 36-37.

assumptions used in a sensitivity analysis.[53] Mr. Chreston disagreed with Mr. Ancona's recommendation that the Commission wait to revise the plant retirement dates, citing the Commission's October 20, 2011 order in Case No. U-16472 as labeling certain generating units as "marginal."[54]

Dr. White's rebuttal testimony addressed Mr. Andrews' revised depreciation rate calculation, contending that Mr. Andrews did not properly adjust the depreciation rates to reflect his revised assumptions. He testified that Mr. Andrews ignored interim retirements, ignored the "half-year convention," and applied an incorrect formula to certain plant accounts by including DTE's adjusted reserve levels for these accounts.[55] Dr. White also addressed Mr. Ancona's recommendation to increase depreciation expense by $39 million to reflect the depreciation reserve imbalance in Dr. White's analysis, without adjusting the depreciation rates for the individual plant accounts. He contended that Staff's recommended approach is inconsistent with depreciation principles.[56]

Mr. Andrews also presented rebuttal testimony. He addressed Staff's recommendation, objecting that Staff's proposal to increase depreciation expense by Dr. White's calculation of the reserve imbalance implicitly accepts DTE's proposals. He testified that if the concerns he raised in his initial testimony, and the concerns Mr. Ancona identified in his testimony, were remedied, the reserve imbalance would be significantly reduced.[57] He disputed that the reserve imbalance should keep pace with plant in service, and testified that if depreciation rates are set based on the remaining

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[53] See Tr 37-42.
[54] See Tr 37.
[55] See Tr 130-134.
[56] See Tr 134-137.
[57] See Tr 200.

lives of the assets, any reserve imbalance will be corrected by the end of the useful lives of the utility plant.[58]

E. Briefs

The briefs of the parties generally track the testimony of their witnesses. In its brief, Staff also offers a revised proposed depreciation expense level to reflect revised retirement dates for the River Rouge, St. Clair, and Trenton plants as proposed by DTE, while also excluding DTE's proposed treatment of obsolete inventory and the additional five-year escalation rates for removal costs. As noted above, only DTE and ABATE filed reply briefs.

III.

DISCUSSION

In the discussion that follows, the dispute regarding the retirement dates for certain generating plants is discussed in section A, the dispute regarding the treatment of Harbor Beach and Conner's Creek removal costs is discussed in section B, the dispute regarding the escalation of removal costs is discussed in section C, and the treatment of obsolete inventory costs is discussed in section D. ABATE's recommended modifications to the net salvage method to reflect the time value of money and to reflect the gain on land sales are discussed in section E and F. Staff's proposed depreciation expense levels are discussed in section G. Undisputed and other issues requiring resolution in this case are discussed in section H. A recommendation regarding revised depreciation rates is presented in section I.

[58] See Tr 200-203.

A. <u>Retirement dates</u>

One of the key disputes among the parties is DTE's use of revised retirement dates for several of its coal-fired and peaking units. DTE did not directly address the changes in its application or in its direct testimony, but the retirement dates underlying the current depreciation rates and the proposed depreciation rates are shown in Exhibit A-15, Statement H, for each unit.[59] In his testimony for ABATE, Mr. Andrews emphasized the significant impact of the changes:

> DTE is proposing to shorten the lifespan of its Belle River, River Rouge, St. Claire, and Trenton Channel Power Plants relative to the final retirement dates approved in U-16117. DTE is proposing for Belle River a final retirement year of 2030, 21 years sooner than previously approved. For River Rouge, the proposed final retirement year is 4 years earlier. For the St. Claire Plant, the proposal is 12 years earlier than previously approved. For Trenton Channel, the retirement date has been moved up 11 years. The depreciation expense increase related solely to the recovery of investment for these four plants alone is $88.8 million.[60]

He objected to the proposed changes, asserting that DTE had failed to present any support in its filing to justify the changes.[61] He testified that in discovery, he requested all supporting studies and workpapers that justify the reduction in service life:

> DTE responded with what appears to be a few pages from a 2015 long term plan and a very brief explanation. I have attached this response as Exhibit AB-1. DTE's response to this discovery request indicates that the proposed early retirement date for these plants is largely based on the implementation of the Clean Power Plan, a proposed EPA regulation meant to reduce CO2 emissions, whose implementation is still pending and ultimate implementation is now problematic based on the actions of the current administration in Washington D.C. DTE's decision to retire a portion of its coal fleet early appears to be premature given there are no regulatory requirements and/or economic justification to retire the plants early.[62]

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[59] See Exhibit A-15, pages 68-74.
[60] See Tr 179.
[61] See Tr 182.
[62] See Tr 179, 182-183. Exhibit AB-1 states in part: "U-16117 assumed Belle River, St. Clair, Trenton, and River Rouge power plants would last 65 years. Since the 2009 depreciation case was filed with fixed

Mr. Andrews testified that DTE had not performed an IRP that justifies shortening the retirement dates:

> In fact, in DTE's pending general rate case, U-18255, DTE is requesting a sum of $3 million of O&M expenses to expand its integrated resource planning ("IRP") activities over and above its actual 2016 spending levels. DTE is requesting these additional expenses so it can be adequately prepared to address a significant transformation to its generation fleet in the coming years. Until such a study is complete and thoroughly reviewed and scrutinized, it is premature to obligate ratepayers to provide significant additional revenues to cover the accelerated depreciation of DTE's coal fleet.[63]

Accordingly, Mr. Andrews recommended that the Commission retain the retirement dates used in the last depreciation case:

> For the Belle River, River Rouge, St. Claire, and Trenton Channel Power Plants, I recommend that the retirement dates last approved in U-16117 remain in place in this proceeding. This will provide DTE with ample time to complete its IRP and complete [a] more definitive plan for the expected life of these units. Increasing depreciation rates before these definitive plans are completed produces an unjustified and unreasonable burden on ratepayers.[64]

Mr. Ancona testified to Staff's concern with the advanced retirement dates:

> While the assumptions included in DTE's study are consistent with DTE's public announcements, they are also a fundamental part of the Integrated Resource Plan (IRP) process. Staff believes it would be reasonable to wait until the Commission has evaluated the retirement decisions in an IRP before adjusting depreciation accrual rates reflecting those retirement dates.[65]

As noted above, in his rebuttal testimony, Mr. Chreston testified that DTE did provide documentation of the economic analysis supporting the new proposed

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65-year plant life estimates, the Company has been evaluating the lifespan of its plants with the expectation that environmental regulations, through the implementation of either the Clean Power Plan (CPP) or other comprehensive or more limited regulatory frameworks, will require either costly plant improvements or reduced operating parameters starting in the early 2020s. Therefore, the Company is tentatively forecasting the retirement of a portion of its coal fired fleet beginning in the early 2020s due to the potential impact of those current and future environmental regulations." See page 1.

[63] See Tr 183.

[64] See Tr 183-184.

[65] See Tr 212.

retirement dates, citing the company's discovery response in Exhibit AB-1. He disputed that the Clean Power Plan was the primary driver of the retirement dates in the company's analysis:

> Due to changes to the Steam Electric Effluent Limitation Guidelines (ELG) and the Cooling Water Intake Regulations (316(b)), the Company performed an analysis to evaluate the impact of investing capital to comply with revised regulations or retiring units prior to the compliance deadline dates. In, addition to that economic analysis other integrated resource planning principles of Reliability, Clean, Flexible and Balanced, Compliant, and Reasonable Risk were considered. Thus, the Clean Power Plan was but one consideration among many others.[66]

Mr. Chreston explained DTE's integrated resource planning principles:

> Reliability is an important integrated resource planning requirement. Plant age is a major factor when considering the reliability of Tier II plants.
>
> Affordability is another consideration. Details of the economic analysis of plant retirements are described in sections below.
>
> The IRP planning principle "Clean" refers to environmental sustainability and low carbon aspirations, considered as major factors in the determination of the proposed course of action. The Company is committed and has a long history of environmental conservation and stewardship.
>
> Flexible and Balanced refers an optimum mix of base, peaking, and non-dispatchable generation that best serves our Company's load profile and the rest of MISO.
>
> The final integrated resource planning principle is Reasonable Risk. By establishing and maintaining a resource portfolio that has a good balance of generation fueled by coal, nuclear, gas and renewables, the Company believes risks around uncertain fuel costs and fuel availability are mitigated.[67]

He disputed that DTE had not performed an IRP sufficient to justify shortening the retirement dates:

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[66] See Tr 35.
[67] See Tr 36.

> Mr. Andrews and ABATE is, or should be, well aware that DTE has completed numerous economic evaluations of plant retirements over a period of years and within the Company's integrated resource plan (IRP) and CON filing in Case No. U-18419 which was filed on July 31, 2017.[68]

He explained that DTE's analysis looked at the net present value (NPV) of continued operation of units or combinations of units for the St. Clair, Trenton Channel, River Rouge, Belle River and Monroe plants until at least 2028, in comparison to retirement by 2023.[69] He then reviewed the results of the company's retirement analysis:

> The economics from this study indicate that it is better to retire St. Clair, Trenton, and River Rouge before the Environmental Retrofits are required in 2023 and it is better to keep operating Belle River and Monroe and make them compliant to the ELG and 316(b) regulations.[70]

In their briefs, citing DTE's pending application for a certificate of necessity under MCL 460.6s in Case No. U-18419, both ABATE and Staff argue that the Commission should wait to revise the retirement dates until the Commission reviews the company's IRP in that case. ABATE argues that a depreciation case is not the appropriate forum in which to make such significant decisions; ABATE also challenges DTE's reliance on certain federal environmental regulations, referred to as the Clean Power Plan, contending that the federal government has now abandoned these regulations.

Staff also presents an alternate calculation in a chart at page 4 of its brief, to show the impact on depreciation expense that would result from adopting DTE's proposed retirement dates for River Rouge, St. Clair, and Trenton Channel. Staff states that the $65.5 million increase in depreciation expense calculated in this chart does not reflect the additional five-year escalation and obsolete inventory treatment proposed by DTE and opposed by Staff. Staff also explains that it has not revised retirement dates

[68] See Tr 36-37.
[69] See Tr 38.
[70] See Tr 40.

for Monroe, Belle River, and Greenwood because "presumed retirement dates for both the current and proposed scenarios are farther in the future and do not need to be addressed in this case."[71]

DTE argues that the Commission should rely on Mr. Chreston's testimony.[72] It further argues that the retirement dates used in Case No. U-16117 were not "approved" in that case, but were based on "facts and regulations in place at the time."[73] DTE also argues that it did not base its retirement analysis solely on the Clean Power Plan requirements, but also on the effluent and cooling-water intake regulations.[74] DTE also notes that in its October 20, 2011 order in Case No. U-16472, the Commission cautioned the company that it would be required to justify new capital investments in plants that were subsequently retired with a positive plant balance.[75] In its reply brief, DTE acknowledges Staff's revised proposal with a depreciation expense level of $65.5 million, but argues that DTE's revised retirement dates for Monroe, Belle River, and Greenwood should also be adopted on the basis that no party expressly opposed the revised retirement dates for those plants.[76] The chart DTE includes in its reply brief at page 5 begins with Staff's revised depreciation expense level of $65 million and calculates an additional $35 million in depreciation expense for Monroe, Belle River, and Greenwood, for a total depreciation expense of $101 million.[77] DTE argues that its calculations follow the same method used in Staff's calculations.

[71] See Staff brief, page 4.
[72] See DTE brief, pages 21-24.
[73] See DTE brief, page 22.
[74] See DTE brief, page 23.
[75] See DTE brief, page 24.
[76] See DTE reply brief, pages 4-5. ABATE, however, did object to the retirement date for Belle River. See Andrews, Tr 175, lines 14-16, Tr 179, lines 7-9, Tr 182 (Table 2); ABATE brief, page 1, pages 3-6.
[77] DTE included a small adjustment ($135,000) for Greenwood in this figure, which appears to reflect increased investment only, since DTE does not appear to have changed the retirement date for

This PFD agrees with ABATE and Staff that a depreciation case is not the place to make substantive planning decisions for the utility regarding its capacity and energy needs for the upcoming decades. Indeed, DTE only presented its NPV analysis as part of its rebuttal testimony in this case. As noted above, ABATE and Staff are content to rely on a decision in Case No. U-18419, which is expected relatively soon. Therefore, this PFD recommends that if the Commission approves DTE's IRP as filed in that case, then it also approve the comparable retirement dates for Belle River, River Rouge, St. Clair, and Trenton Channel for use in this depreciation case. Correspondingly, if the Commission does not approve the IRP in its final order in Case No. U-18419, the Commission should defer revising the retirement dates for the pertinent plants until the Commission completes its review of the company's IRP due to be filed by March 29, 2019, in accordance with the Commission's orders in Case Nos. U-18418 and U-18461.

While DTE asserts there is no dispute regarding the retirement date for Belle River, ABATE clearly disputed the change.[78] And while Staff argues that a decision regarding Belle River can be deferred to a future depreciation case along with Monroe and Greenwood, the 20-year change in retirement dates for the Belle River units is significant. Thus, if the Commission does approve DTE's revised retirement date of 2030 for Belle River in Case No. U-18419, this PFD finds that it is reasonable, and consistent with Staff's and ABATE's arguments, for the depreciation rates for Belle River to be revised accordingly in this case. Regarding Monroe and Greenwood, as

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Greenwood from the 2045 date used in Case No. U-16117. The adjustment for Monroe is approximately $1.7 million, but the increase also does not appear to be attributable to the retirement dates, since DTE is proposing to extend the retirement dates for the Monroe units from the 2037-2040 range used in Case No. U-16117 to a 2042-2045 range.

[78] See Andrews, Tr 175, lines 14-16, Tr 179, lines 7-9, Tr 182 (Table 2); ABATE brief, page 1, pages 3-6.

DTE argues, no party challenged the retirement dates used in the depreciation study for those plants, so there is no dispute to resolve. Nevertheless, it should be noted that DTE's depreciation study uses extended retirement dates for the Monroe units, and has not changed the retirement dates for Greenwood, as shown in Exhibit A-15, Statement H.[79]

B. <u>Net Salvage for Harbor Beach and Conner's Creek</u>

DTE retired the Conner's Creek and Harbor Beach power plants in 2011 and 2013 respectively. Mr. Cooper and Mr. Mortensen testified that DTE expects to incur additional costs of dismantling these power plants between 2018 and 2020.[80] Mr. Cooper testified that he directed Dr. White to add the projected costs totaling $40.3 million--$28.1 million for Conner's Creek and $12.2 million for Harbor Beach--to the projected costs of removal for the River Rouge plant, which DTE expects to retire in approximately 2020:

> Since Dr. White's model tracks reserves down to the specific steam plant or unit level, I have instructed him to include the Conner's Creek and Harbor Beach removal costs in with the River Rouge plant's removal costs. The River Rouge plant is scheduled to retire in 2020 and the removal costs to be incurred around 2025. As a result, the timing of the River Rouge Plant removal costs in the closest to when the Conner's Creek and Harbor Beach removal costs are expected to be incurred.[81]

He explained that the Harbor Beach costs were not included in the Sargent & Lundy study because DTE had expected to sell the plant, so Mr. Mortensen presented the cost projections separately.[82]

[79] See Exhibit A-15, pages 66-67.
[80] See Cooper, Tr 152-153; Mortensen, Tr 96-97.
[81] See Tr 153.
[82] See Tr 151-152.

ABATE objected to DTE's proposed recovery of the Conner's Creek and Harbor Beach removal costs through the River Rouge depreciation rates. Mr. Andrews characterized DTE's proposal to recover estimated depreciation costs of Conner's Creek and Harbor Beach through the depreciation rates for the River Rouge plant as "inappropriate."[83] Mr. Andrews also proposed that the Commission consider that DTE received purchase offers for the Harbor Beach plant, recommending that land values be considered as an offset to the cost of removal.[84] This proposal is discussed in more detail below.

In his rebuttal testimony, Mr. Cooper defended his decision to include the projected Conner's Creek and Harbor Beach costs as part of the River Rouge removal costs:

> There is no reason to exclude the Conner's Creek and Harbor Beach decommissioning costs from this filing. As mentioned on page 10 of my direct testimony, the industry recognizes three distinct phases of the plant removal process: decommissioning, decontamination, and demolition. The Conner's Creek and Harbor Beach plants are retired but as stated on Exhibit A-6 only half of the decommissioning and decontamination phases have been completed for these plants. In this case, DTE is seeking to recover the remaining costs to be incurred to remove these plants, which is $28.1 million for Conner's Creek and $12.2 million for Harbor Beach as shown on Exhibit A-6. The Conner's Creek and Harbor Beach costs are included with the River Rouge costs in Witness Dr. White's Depreciation Study to recover these costs. *Absent this treatment, there would be no plant base against which to apply an accrual rate for the cost of removal*. River Rouge was selected because the timing of decommissioning this plant is closest to when the Conner's Creek and Harbor Beach costs will be incurred.[85]

[83] See Tr 175; also see Tr 185, 189, 194.
[84] See Tr 186.
[85] See Tr 164.

In its briefs, DTE relies on Mr. Cooper's testimony, quoted above.[86] DTE acknowledges that it is considering acquisition contracts for Harbor Beach that would transfer the removal obligation at a fixed cost to DTE.[87]

ABATE relies on Mr. Andrews' testimony, arguing that the timing of the Harbor Beach and Conner's Creek removal costs are not similar to the proposed River Rouge retirement and objecting that DTE escalates these costs to 2025 along with the River Rouge removal costs.[88]

This PFD finds that DTE has not supported its proposal to attach unanticipated costs of removal for Harbor Beach and Conner's Creek to the projected removal costs for River Rouge. DTE has not cited to any prior Commission order permitting this atypical combining of accounts. DTE has acknowledged that it could not include the projected costs in net salvage absent this atypical and unusual treatment.[89] Moreover, as ABATE argues, the timing of the two retirements is not similar. Even though Mr. Cooper testified that the Harbor Beach and Conner's Creek removal costs are expected to be incurred between 2018 and 2020,[90] as ABATE argues, DTE has inflated these costs to 2025 along with the River Rouge projected removal costs.[91]

Because DTE is using a remaining-life method of depreciation, this PFD finds that DTE will recover the additional net salvage costs associated with the retirement of these units through future depreciation cases. This is so because the remaining-life method is essentially self-correcting: the additional removal costs will reduce the

[86] See DTE brief, pages 28-29, reply brief, pages 14-15.
[87] See DTE brief, page 29.
[88] See ABATE brief, pages 10-11, reply brief, page 3.
[89] See Cooper, Tr 164.
[90] See Cooper, Tr 153-154.
[91] See Statement G of Dr. White's depreciation study (internal page 62), Exhibit A-15, page 65.

accumulated depreciation offset to plant investment and thus increase the balance (i.e. the reserve imbalance) to be recovered through the remaining-life method in DTE's next case after the removal costs are incurred.[92] Mr. Cooper's testimony indicating that if the Commission does not approve DTE's request, "there would be no plant base against which to apply an accrual rate for the cost of removal,"[93] wrongly suggests that DTE will not recover these costs in the absence of approval of its proposed treatment. Mr. Cooper acknowledged in his direct testimony that removal costs incurred to date for these plants after they retired are included in the actual depreciation reserve balance.[94] DTE has not provided any compelling reason for the Commission to provide an alternative means of recovery. If DTE nonetheless wants to make an argument that it should recover these costs faster than it otherwise would through the depreciation process, it may do so in its next rate case.

C. Five-year post-retirement escalation of net salvage costs

The Sargent & Lundy studies estimated removal costs as of January 31, 2016.[95] For these removal costs, and the Harbor Beach removal costs separately identified by Mr. Mortenson, Mr. Cooper testified that he directed Dr. White to include the costs escalated to a date five years after the retirement date for each of the plants, using a composite rate of inflation of 2.2%.[96] He explained: "The five-year period considers

[92] See Andrews, Tr 200-201; see White, Tr 104-105, 134-136.
[93] See Tr 164, also quoted above.
[94] See Tr 152.
[95] See Exhibit A-14, Schedule N3, page 17. Also note that Sargent & Lundy relied on DTE's estimates of the decommissioning and decontamination costs, and provided an independent estimate of the demolition costs. See Exhibit A-14, Schedule N3, page 35. DTE did not present testimony regarding the development of these costs, although Mr. Horgan testified to significant exclusions, and no party objected to the estimates.
[96] See Tr 154. Mr. Cooper testified that the 2.2% rate reflects a weighted average, using a 75% weighting for a Consumer Price Index (CPI), and a 25% weighting for a Producer Price Index (PPI). In Case Nos. U-

the planning for and actual decommissioning of the plant after retirement."[97] The escalation is shown in Statement G of Dr. White's Exhibit A-15.[98]

Staff and ABATE object to the escalation. Mr. Andrews calculated that the additional five-year escalation adds $78 million or 11.5% to the total removal costs DTE proposes to recover over an approximately 18-year average remaining life:

> This is simply an attempt to unjustly collect additional revenues from customers. There is no basis for this escalation. At the 2.2% inflation rate used by the company, this results in the costs at the retirement year to be further inflated by 11.5%. Mr. Cooper states this five-year period considers the planning for and actual decommissioning of the plant after retirement. There is no reason that planning for the decommissioning cannot occur prior to the final retirement date. Furthermore, the year of final retirement is the year in which the last generating unit and common facilities are retired, some of the decommissioning work can likely be performed on the generating units that retire prior to the final retirement year. DTE's proposal is to recover over the remaining lives of its steam production plants $758 million of escalated, estimated decommissioning costs. Of that amount, $78 million is entirely due to DTE's supposed delay between the final retirement date and the time when decommissioning costs are expended.[99]

Mr. Ancona characterized the five-year escalation as arbitrary:

> The projected balance attributable to obsolete inventory for plants not subject to retirement for several years is pure speculation. It is Staff's recommendation that any recovery of amounts for obsolete inventory be assessed after a plant is actually retired, and after all salvage options have been exhausted.[100]

In rebuttal, Mr. Cooper testified:

> With regard to Witness Andrews' position, while it is true that most planning and some decommissioning work can be completed on generating units that retire prior to the year when the last generating unit is taken out of service and the plant is retired, he is missing key factors in

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16117 and U-16991, the Commission adopted a 50-50 weighting, but no party raised a concern with the 75-25 composite chosen by DTE in this case.

[97] See Tr 154.
[98] See Exhibit A-15, page 65.
[99] See Tr 185-186, footnotes omitted.
[100] See Tr 213.

> the timing and costs of the work involved in decommissioning and removing plants. His assumption that all decommissioning costs can be incurred during the final retirement year of the plant is not realistic. Staff Witness Ancona's conclusion that DTE Electric is arbitrarily increasing the estimated decommissioning costs for an additional five years, demonstrates that his position is very similar to Witness Andrews' and as a result, he too is missing key factors in the timing and costs of the work involved in decommissioning and removing plants.[101]

Referencing Mr. Charles of Sargent & Lundy, he further explained:

> As mentioned on page 10 of my direct testimony, the industry recognizes three distinct phases to the project of fully decommissioning and removing a power plant. They are: Decommissioning, Decontamination, and Demolition. Company Witness Charles of Sargent & Lundy estimates that approximately 25% of the overall project costs are incurred in the Decommissioning and Decontamination phases and 75% of the costs are incurred during the Demolition phase. The Decommissioning and Decontamination phases, which combined take a year or more to complete, can be done on the units that retire prior to the year when the last generating unit and the plant are retired. However, this work cannot begin on the last generating units and common facilities until after they are taken out of service in the final year of plant retirement. As a result, Decommissioning and Decontamination work on these assets will go on for a year or more after the plant has been retired. In addition, the Demolition phase, where an estimated 75% of overall decommissioning project costs are incurred, cannot begin until after the Decommissioning and Decontamination phases have been completed on all units and the common facilities. Demolition work can take up to three years to complete depending on the size of the plant. Also, after demolition has been completed, an additional one to two years of site restoration work is required to satisfy the requirements of the Michigan Department of Environmental Quality (MDEQ) and receive a "No Further Action" (NFA) letter.[102]

DTE argues in its brief that the five-year post-retirement removal cost escalation reflects the time period when removal costs will be incurred, citing Mr. Cooper's testimony. It contends that the five-year period is fully supported by the Sargent & Lundy study as well as Mr. Cooper's testimony.[103]

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[101] See Tr 166-167.
[102] See Tr 167.
[103] See DTE brief, pages 24-26, reply brief, pages 6-7, 11.

This PFD concludes that DTE has not established that its proposed additional five-year escalation is a reasonable projection of the timing of removal cost payments, or that is a reasonable modification of the current method of escalating removal costs to the date of retirement. DTE provided no basis for the five-year estimate in its direct testimony. In his rebuttal testimony, Mr. Cooper acknowledged that substantial work can be done even before retirement and outlined an approximately five-year process for the work to be completed.[104] He did not attempt to establish five years as the mid-point of the total expenditures, indicating only that 75% of the expenditures were expected to take place within that timeframe.

As Mr. Andrews recognized, DTE has also not established that this proposed refinement to the traditional method is appropriate given the other simplifications inherent in the method as recognized by the Commission. In this context, Mr. Andrews recommended that the Commission include recognition of the time value of money and presented an example of calculations that would limit current customer contributions in recognition that future contributions of the same nominal dollar value would be worth less in real dollar terms. While as DTE argues, and as discussed in more detail below, the Commission has declined to include an explicit recognition of the time-value of money in the net salvage method, the Commission's rationale has primarily been to avoid unnecessary complexity in the method. As Staff and ABATE note, the five-year additional escalation adds over 10% to the projected costs. Note that any errors in the projected inflation rate are magnified during the last five years of the projection period. Also, as Mr. Andrews explained, the remaining-life method is self-correcting over time,

[104] As quoted above, he outlined a process with one year to complete decommissioning and decontamination, up to three years to complete demolition, and one to two years to complete site restoration.

such that actual removal costs above estimated costs will be recovered through future depreciation rates.[105]

While DTE cites its experience with Marysville and Harbor Beach to support the additional inflation, DTE earlier asserted that neither were good models for removal cost estimates. In his testimony, Mr. Mortensen asserted that DTE's experience with its Marysville power plant should not be "used as a benchmark" for the cost to decommission, decontaminate and demolish other DTE power plants. DTE further relies on Mr. Mortensen's testimony as follows to establish that the Marysville's resale potential was unique:

> Marysville power plant was an exception due to the location of the property (potential reuse by future developers) and its scrap value. The Marysville Power Plant property has railroad, major highway and deep water port potential for Michigan that enhances its property reuse.[106]

This argument is not persuasive. First, DTE did not establish that other plants lack similar attributes, or other attributes that may enhance their property reuse. Nor did DTE establish that Marysville's percentage scrap/salvage value is well above the estimates for other plants to be decommissioned.

More significantly, the examples cast further doubt on DTE's assertions regarding the timing of demolition costs. As to the Marysville plant, in 2012 DTE issued a Request For Proposal (RFP) for demolition of the plant which included an option for the contractor to submit an alternate proposal to purchase the plant site "as is – where is".**[107]** As a result, in 2014, DTE sold the Marysville plant to a buyer who then became

[105] See Tr 202-203. Also see White, Tr 110 ("A remaining-life rate is equivalent to the sum of a whole-life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category.")
[106] See Tr 95-96.
[107] See Exhibit A-12.

responsible for demolition and remediation.[108] Thus, DTE did not undertake any demolition of that plant, nor did DTE incur remediation costs over a period of years to obtain approval from the Michigan DEQ.[109] Rather, it was the buyer (Commercial Development Company) who incurred demolition and remediation costs, and who is waiting for DEQ approval.[110]

As to the Harbor Beach plant, it is also not clear that DTE will directly incur demolition or remediation costs for that facility. In 2016, DTE issued an RFP for demolition of the Harbor Beach plant which included an option for a contractor "to submit an alternate proposal to purchase the Harbor Beach plant site "as is – where is".[111] The Harbor Beach demolition RFP was issued to nineteen qualified demolition bidders "including known interesting development companies", and nine proposals were received "including three purchase offers."[112] Thus, as with Marysville, it is possible that the Harbor Beach plant will be sold without DTE having to incur any demolition and remediation costs or any delay for DEQ approval.

What these examples illustrate is the reasonableness of limiting inflation projections to the date of retirement. Methodologically, using the retirement date as the point in time to estimate the removal costs is reasonable, since DTE could theoretically

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[108] As DTE's Mr. Mortensen testified, "[t]he sale transferred the liability to remove and demolish the plant to the buyer." See Tr 95.

[109] Pursuant to the sale of the plant and property for $0.5 million, DTE avoided having to incur an estimated $31.9M in demolition costs. See Tr 96. As Mr. Mortensen testified: "It made financial sense to shift the cost of completing the decommissioning and demolition of the plant to the developer. The difference between the price paid and the demolition cost can be attributed to the developer's future value from reuse of the land and the scrap value." Id. See also, Exhibit A-12 ("DTE ultimately selected to sell the plant based on the best overall value proposal resulting in a cash positive analysis.")

[110] See Tr 145. While DTE points to the "additional one to two years of site restoration/environmental work" to satisfy the requirements of the MDEQ and receive a NFA letter, DTE did not establish that the time waiting for DEQ review will entail significant additional expenditures if the activities were properly designed and performed in the first place.

[111] See Exhibit A-12.

[112] See Exhibit A-12.

contract for the entire project at the time of retirement, thus fixing the total costs in then-current dollars, allowing the contractor to manage inflation over the time period with offsetting interest accrued on the funds received in advance of the costs.[113]

D. Obsolete Inventory

Mr. Cooper testified that he also directed Dr. White to set depreciation rates to collect $62 million in costs Mr. Cooper labeled "obsolete inventory" associated with the baseload and peaking plants DTE now contends will retire between 2020 and 2040, or later. Mr. Cooper listed the costs by plant in Exhibit A-4 and incorporated them in the net salvage costs in Exhibit A-6. In his direct testimony, he cited the Commission's May 20, 2016 order in Case No. U-18033 (May 2016 Order) as authorization for the company's request.[114]

Staff and ABATE took issue with including these amounts with the net salvage costs in the depreciation rate calculations. Mr. Andrews testified that DTE had failed to support the level of obsolete inventory it is attempting to recover and disputed that the May 2016 Order authorized DTE to recover obsolete inventory through the net salvage rates for its steam production plants.[115] Mr. Ancona testified:

> The projected balance attributable to obsolete inventory for plants not subject to retirement for several years is pure speculation. It is Staff's recommendation that any recovery of amounts for obsolete inventory be assessed after a plant is actually retired, and after all salvage options have been exhausted.[116]

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[113] Note that the demolition cost estimates already include a contractor profit of 10%. See Exhibit A-14, Schedule N1 (page 33), Schedule N2 (page 28), and Schedule N3 (page 41).
[114] See Tr 152.
[115] See Tr 187-188.
[116] See Tr 213.

In his rebuttal testimony, Mr. Cooper presented Exhibit A-16 to show that the list of inventory included in the company's calculations had been provided to ABATE in discovery. He also addressed Case No. U-18033, testifying:

> The Order in Case No. U-18033 was an accounting order. The financial impacts of an accounting order are subject to review in a contested case addressing cost of service and rate making issues. The Company is now requesting recovery of these costs in this contested depreciation case. In its filing, DTE Electric has followed the methodology approved by the Commission in U-18033. *The Company has reflected the obsolete inventory write-off as a cost of removal charge to accumulated depreciation to be recovered through the Depreciation Rates set in this Case*.[117]

Further, responding to Mr. Ancona, he testified:

> At page 2 of the Commission's May 20, 2016 Order in Case No. U-18033, it states: "The Commission considered the alternatives proposed by DTE Electric and finds it reasonable for the inventory O&M expenses resulting from the write-down of the inventory value to be charged to accumulated depreciation. By allowing the company to charge amounts to accumulated depreciation as a cost of removal, DTE Electric may recover the costs through depreciation rates when rates are reset in the next depreciation case." Case U-18150 is DTE Electric's first filed depreciation case since the Order in U-18033. The term write-down refers to the accrual of a reserve based on an estimate of realizable value. The term write-off relates to removing assets from the balance sheet, usually at the time of disposal, or upon a decision to not pursue additional salvage or collection [activities]. This distinction is important because the order refers to a write-down of inventory value. Write-downs are accrued before assets are disposed. Staff's position to exclude the reserve (i.e., the write down) from the net salvage estimates is inconsistent with the Order in U-18033. Furthermore, Staff's suggestion would effectively negate the intention for the original accounting request. That is, the Company is required to write-down the inventory value under both GAAP and regulatory accounting. Absent the accounting provided by the order in U-18033, the Company would have to expense the write-down as it is accrued. Clearly, the accounting provided by the Commission was [intended] to avoid the immediate expensing of the write-down of obsolete inventory, and instead recognize the cost over the remaining useful life of the assets.[118]

[117] See Tr 159-160 (emphasis added).
[118] See Tr 162.

In its brief, DTE relies on Mr. Cooper's testimony and the May 2016 Order to support its request. It disputes that the costs are speculative:

> Contrary to ABATE and Staff witnesses' assertions, DTE Electric has fully supported the level of obsolete inventory it is requesting to be recovered through net salvage rates. Exhibit A-4 provides a breakdown of DTE Electric's total obsolete inventory balance of $68.7 million by coal plant location as well as amounts associated with the peaking facilities. It provides DTE Electric's calculation of the estimated total write-off of $61.8 million to be recovered through net salvage rates after deducting 10% of the inventory's value in the form of salvage. These are actual, not speculative amounts. A detailed listing of the inventory by line item including the quantity, the unit price, and the calculated cost of the inventory is included in Exhibit A-16. The total value of the detailed inventory listing is $71.8 million, which equals the balance on the Company's books prior to being adjusted for MPPA's 18.61% interest in the Belle River Plant.[119]

DTE also maintains that its proposal "reflects the intention of" the May 2016 Order:

> Approval of the obsolete inventory costs in this case is reasonable and prudent and reflects the intention of the Order in Case No. U-18033. In that Order, the Commission stated: The Commission considered the alternatives proposed by DTE Electric and finds it reasonable for the inventory O&M expenses resulting from the write-down of the inventory value to be charged to accumulated depreciation. By allowing the company to charge amounts to accumulated depreciation as a cost of removal, DTE Electric may recover the costs through depreciation rates when rates are reset in the next depreciation case. (Case No. U-18033 Order dated May 20, 2016, p. 2) As referenced in the Order, the term write-down refers to the accrual of a reserve based on an estimate of realizable value. The term write-off relates to removing assets from the balance sheet, usually at the time of disposal, or upon a decision to not pursue additional salvage or collection activities. This distinction is important because the order refers to a write-down of inventory value. Write-downs are accrued before assets are disposed. Staff's position to exclude the reserve (i.e., the write-down) from the net salvage estimates is inconsistent with the Order in Case No. U18033. (2T 161) Absent the accounting provided by the order in Case No. U-18033, the Company would have to write-down the inventory value under both GAAP and regulatory accounting principles and expense the write-down as it is accrued. The accounting provided by the Commission was intended to avoid the immediate expensing of the write-down of obsolete inventory and instead recognize the cost over the remaining useful life. Accordingly,

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[119] See DTE brief, pages 29-30, citing Tr 160; also see DTE reply brief, pages 11-12.

> the Commission should approve the recovery of obsolete inventory costs in the Company's net salvage values.[120]

Staff and ABATE argue in their briefs that DTE's proposed treatment of projected obsolete inventory expense is inconsistent with the Commission's May 2016 Order and does not permit review of actual obsolete inventory amounts. Staff argues:

> Specifically addressing obsolete inventory, Staff believes DTE misunderstood its concerns, as it is not asking DTE to expense depreciation amounts. Staff's concerns are that the included amounts, in this case, for "obsolete inventory" are projections for plant not yet retired, rather than actual obsolete inventory, as the date of obsolescence is not yet determined. DTE's rebuttal contains a laundry list of items it wishes to include in obsolete inventory upon retirement, whenever that may be. (Exhibit A-16) But, DTE does not, and cannot, know if those will be the residual amounts, which would offset costs, at the time of actual retirement. Staff is proposing that recovery of obsolete inventory be approved and allowed after it has become obsolete, and the amounts are certain, not projected. Staff, thus, submits that contingency, such as unknown amounts of obsolete inventory, should be removed from any increase at this time.[121]

Staff argues that the Commission's May 2016 Order contemplates a later recovery of obsolete inventory expense, "once the amounts, including any residual value, are determined."[122]

DTE's reply brief repeats essentially verbatim its arguments as quoted above. It also argues that ignoring its obsolete inventory "turns ratemaking on its head" by requiring actual obsolete inventory values rather than relying on estimated values.[123]

In Case No. U-18033, the Commission addressed DTE's February 2, 2016, application on an *ex parte* basis. The application recited that the company is in the process of retiring certain generating units and plants, and further explained:

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[120] See DTE brief, pages 30-31; also see DTE reply brief, page 12.
[121] See Staff brief, page 5.
[122] See Staff brief, page 5.
[123] See DTE reply brief, page 8.

> Upon retirement of the units and/or plants, the Company will sell or transfer the spare parts if possible, but some spare parts inventory will remain that cannot be repurposed or sold for book value. Absent other more reasonable options, this will result in a charge to expense when the plants are considered probable to retire from an accounting perspective.[124]

The company sought accounting authority to "defer for future recovery, the actual O&M expense resulting from the write down of the inventory value, related to retiring plants, to its net realizable value in account 182.3, Other Regulatory Assets." Under this proposal, the company sought to amortize the regulatory asset created over a five-year period effective with its inclusion in base rates.[125] In the alternative, DTE asked "to allow the expense to be charged to accumulated depreciation."[126] DTE further represented:

> Recovery of the deferred inventory expense will be requested in general rate cases brought before the Commission. Therefore, DTE Electric requests only accounting authority to record and defer the costs associated with the obsolete inventory as described above and as further supported in the accompanying Affidavit of Theresa Uzenski.[127]

In her affidavit, Ms. Uzenski further addressed the company's alternative proposal:

> As an alternative to treatment as a regulatory asset, the Company suggests that another option is for the Commission to allow the cost to be charged to accumulated depreciation as a cost of removal. The Uniform System of Accounts defines Cost of Removal as, "the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto." While the loss resulting from the disposal of inventory is not a direct cost of removal, it does *result from* retirement and removal of the generation unit or plant.[128]

She further stated:

> The accounting authority requested in the Company's Application "will not result in an increase in the cost of service to customers." Recovery of the

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[124] See February 2, 2016 application, paragraph 2, page 2.
[125] See February 2, 2016 application, paragraph 4, page 2.
[126] *Id.*
[127] See February 2, 2016 application, paragraph 5, page 2.
[128] See Affidavit, paragraph 6, page 3.

> deferred inventory expense will be requested in general rate cases brought before the Commission. Therefore, DTE Electric is requested only accounting authority to record and defer the costs associated with the obsolete inventory. Moreover, approval of the relief required in the Company's Application does not preclude parties to a DTE Electric general rate case from challenging the recovery, through future rates, of amortized or unamortized plant inventory costs.[129]

The application requested that the accounting authority be granted "as soon as practicable prior to April 2016 to ensure proper and timely accounting in advance of the retirement of electric generation unit Trenton 7A, which is expected in April 2016." It went on to state: "The requested accounting authority would also apply to other electric generating unit and plant retirements *in the future*."[130]

In its May 2016 Order, the Commission reviewed the company's request as presented in the application:

> Upon retirement of the units and/or plants, the company will sell or transfer the spare parts if possible. DTE Electric explained that the cost of spare parts that cannot be repurposed or sold for book value must be written off. *Absent other more reasonable options*, the write-off will result in a charge to expense (to re-measure the inventory at the net realizable value) when the plants are considered probable to retire from an accounting perspective.[131]

The Commission also cited the recitation in the application that the parties to a rate case would not be precluded from challenging the recovery, through future rates, of amortized or unamortized plant inventory, parts, and equipment costs.[132] The Commission adopted the alternate accounting authorization requested by DTE:

> The Commission considered the alternatives proposed by DTE Electric and finds it reasonable for the inventory O&M expenses resulting from the write-down of the inventory value to be charged to accumulated depreciation. By allowing the company to charge amounts to accumulated

[129] See Affidavit, paragraph 8, page 3; also see Application, paragraph 7, page 3.
[130] See Application, paragraph 6, pages 6-7 (emphasis added).
[131] See May 2016 Order, pages 1-2 (emphasis added).
[132] See May 2016 Order, page 2.

> depreciation as a cost of removal, DTE Electric may recover the costs through depreciation rates when rates are reset in the next depreciation case. In addition, it will provide the Commission Staff and other parties an opportunity to review the obsolete inventory for prudence prior to inclusion in depreciation rates.[133]

This PFD concludes that DTE's proposal to treat projected obsolete inventory costs as a cost of removal is inconsistent with the authority provided by the Commission in its May 2016 Order, and its projection of obsolete inventory costs is not supported by the record.

First, the May 2016 Order authorized DTE to charge obsolete inventory costs to accumulated depreciation, and then to recover those costs through a subsequent depreciation case. As Mr. Andrews testified, the order does *not* authorize DTE to recover a projected obsolete inventory expense in advance of a charge to accumulated depreciation, through the mechanics of the net salvage cost calculation.[134] As explained above, the remaining-life method will recover the difference between the plant investment and the accumulated depreciation over the remaining life of the assets. If the accumulated depreciation balance is reduced to reflect the obsolete inventory charge, this will increase the amount to be recovered through depreciation rates, all else equal. Because the approved method provides for this recovery, there is no need for, and the Commission did not authorize, DTE to recover obsolete inventory as an addition to net salvage values otherwise recovered through depreciation rates.

Second, the timing of DTE's characterization of its plant inventory as "obsolete" is inconsistent with its presentation in Case No. U-18033. In its February 2, 2016 application in Case No. U-18033, DTE premised its request for an *ex parte* order in part

[133] See May 2016 Order, page 2.
[134] See Tr 188.

on the need to expense $2.4 million in obsolete inventory associated with the imminent retirement of Trenton Unit 7A:

> DTE Electric further requests that this accounting authority be granted as soon as practicable prior to April 2016 to ensure proper and timely accounting in advance of the retirement of electric generation unit Trenton 7A, which is expected in April 2016. The requested accounting authority would also apply to other electric generation unit and plant retirements in the future. The retirement of Trenton 7A in April 2016 will require the recording of approximately $2.4 million to expense with a credit to the reserve of obsolete inventory within account 154, Plant Materials and Office Supplies, as set forth in the accompanying Affidavit of Theresa M. Uzenski.[135]

DTE thus indicated that Trenton Unit 7A was retiring in 2016 and requested the approval by April in order to avoid recognizing the expense without a means of recovery. The February 2016 application identified only the inventory costs associated with Trenton Unit 7A as the known obsolete inventory costs to be dealt with, accompanied by the statement: "The requested accounting authority would also apply to other electric generation unit and plant retirements *in the future*." [136] (emphasis added). Nothing in the application would have prepared the Commission to consider essentially all the inventory associated with DTE's steam generating plants as "obsolete" as of December 31, 2015, for plants that DTE now projects will retire between 2020 and 2040 or later. Again, in its application, DTE indicated that it was reasonable and prudent for it to hold the inventory:

> It is necessary for each power generating unit to have access to an inventory of readily available spare parts to support unit availability. Some of the parts are unique to specific units and/or plants and some of DTE Electric's older generation units and/or plants use some parts that are no longer routinely manufactured or commercially available. Thus, obtaining specially manufactured replacement parts could, in some instances, take many months. Therefore, the Company maintains a reasonable level of

[135] See Application, paragraph 6, pages 2-3.
[136] See Application, paragraph 6, pages 3.

> spare parts inventory on hand until the plant is taken out of service. Upon retirement of the units and/or plants, the Company will sell or transfer the spare parts if possible, but some spare parts inventory will remain that cannot be repurposed or sold for book value.[137]

The Commission's May 2016 Order reiterated this statement, and explained:

> Upon retirement of the units and/or plants, the company will sell or transfer the spare parts if possible. DTE Electric explained that the cost of spare parts that cannot be repurposed or sold for book value must be written off. Absent other more reasonable options, the write-off will result in a charge to expense (to re-measure the inventory at the net realizable value) when the plants are considered probable to retire from an accounting perspective.[138]

Mr. Cooper's distinction between "write-off" and "write-down" is unpersuasive to show that the Commission intended DTE to recognize and recover obsolete inventory costs far in advance of plant retirements. The Commission used both terms interchangeably in its order, as shown from its statement that "the write-off will result in a charge to expense. . ." A "write-down" at less than the full value of the inventory is merely a "write-off" of the difference between the inventory balance and the projected salvage value of the inventory. The distinction in terms in no way controls the timing of the adjustment. What is critical is that the Commission intended that an actual determination of obsolete inventory would be made and charged to accumulated depreciation, near the time of plant retirement, so that the costs could be reviewed in the company's subsequent depreciation case. Again, the Commission provided that the obsolete inventory costs could be recovered as a reduction to the accumulated provision for depreciation, which DTE identified as one of two alternatives to the more immediate "write-down" described in its application.

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137 See Application in Case No. U-18033, paragraph 4, page 2.
138 See May 2016 Order, pages 1-2.

Not only is the temporal distance between the retirement date and the date of DTE's identification of obsolete inventory vastly different between DTE's application in Case No. U-18033 and its presentation in this case, but DTE has also failed to explain how it can rely on the Commission's May 2016 Order to justify the treatment of inventory balances for the prior calendar year. If DTE truly believed that accounting required those inventory costs to be expensed as obsolete as of the end of 2015, it should have sought accounting approval at an earlier time, and it should have disclosed the costs to the Commission in its application, or it should simply have expensed them without the benefit of the accounting authorization provided in Case No. U-18033.

Finally, as ABATE and Staff contend, DTE did not establish that it accurately identified obsolete inventory.[139] Mr. Cooper was the only witness to provide direct testimony on this topic, and his direct testimony was limited to the following:

> Also, in accordance with the Commission's order dated May 20, 2016 in Case No. U-18033, DTE Electric has included $61.8 million of costs related to Obsolete Inventory in the removal costs for this filing. It is assumed that these costs are incurred at the time of Plant demolition but the costs are not escalated from their December 31, 2015 book values. See Exhibit A-4 for a schedule of Obsolete Inventory by Plant. I instructed Witness Dr. White to make these adjustments to his Depreciation Study for this case. Please see Exhibit A-6.[140]

He also presented Exhibits A-4 and A-6. Exhibit A-4 is a spreadsheet that states for each plant listed[141] "inventory balances as of 12/31/15", "assumed salvage rate" the notation "Obsolete Inventory Balances by Plant as of 12/31/15 per Fossil Generation Controllers (Exhibit A-4). DTE presented nothing else in its direct case to support that

[139] See Andrews, Tr 188.
[140] See Tr 152.
[141] The plants DTE reports obsolete inventory for in column a of Exhibit A-4 include: Monroe, Belle River, River Rouge, St. Clair, Trenton Channel, Greenwood, Renaissance Peaker, Dean Peaker, and Other Peakers.

the $62 million accurately reflects "obsolete inventory." He did not explain how the determination was made or attempt to justify the use of the 10% salvage figure. In contrast, the Commission order clearly contemplated that at the time DTE sought cost recovery of the obsolete inventory balances, they could be reviewed for reasonableness and prudence:

> By allowing the company to charge amounts to accumulated depreciation as a cost of removal, DTE Electric may recover the costs through depreciation rates when rates are reset in the next depreciation case. In addition, it will provide the Commission Staff and other parties an opportunity to review the obsolete inventory for prudence prior to inclusion in depreciation rates.[142]

In its application, DTE told the Commission this review would take place before the costs were passed on to ratepayers. In this depreciation case, however, in seeking recovery of the additional $62 million as an add-on to the cost of removal estimated in the depreciation rate formula, DTE relies on a flat 10% figure for all inventory (without regard to the time remaining from the end of 2015 to DTE's tentative retirement dates for each plant) which Mr. Cooper only mentioned in his rebuttal testimony, and has failed to support. This PFD thus finds Mr. Andrews' testimony persuasive that DTE failed to support the level of obsolete inventory it is claiming and finds Mr. Ancona's testimony persuasive that the level of obsolete inventory claimed by DTE is pure speculation.

Mr. Cooper's rebuttal testimony to the effect that he provided ABATE with a list of all the inventory included in the dollar figures in Exhibits A-4 and A-6, which he reprinted in Exhibit A-16, is irrelevant to the question whether the inventory should be deemed obsolete from an accounting perspective. Also, the accounting treatment provided in

[142] See May 2016 Order, page 2.

the Commission's order could be viewed as a modification of that treatment because DTE presented it as such.) DTE used the language "probable to retire from an accounting perspective," but that cannot mean as soon as a tentative retirement year is set: by this standard, every plant is "probable to retire," because as soon as it is built, it has a life expectancy. DTE has provided no context or justification for claiming that it is required by accounting convention to consider all of its plants "probable to retire" so as to trigger an inventory expense, since all plants are "probable to retire" at some point.

Mr. Andrews' testimony and ABATE's brief highlights how absurd it is to attempt to evaluate the extent to which inventory is obsolete for plants that will not retire for 4 to 24 or more years. For example, as shown in Exhibits A-4 and A-6, $20.6 million of the obsolete inventory costs are associated with the Monroe plant, which Mr. Chreston testified DTE now plans to retire in 2040 or later. An additional $12.4 million is shown for Belle River, with a currently-proposed retirement date of 2030.[143] In its reply brief, DTE only mentions plants it claims will retire between 2020 and 2023, ignoring the significant obsolete inventory costs it has also included for Monroe and Belle River, as shown in Exhibit A-4, with substantially later retirement dates under DTE's own proposal:

> [T]he reality is that DTE Electric has been perfectly clear and consistent in indicating that it "is in the process of retiring certain generation units and plants." (Case No. U-18033 Order dated May 20, 2016, p. 1) Staff agrees that the Company's proposed generation retirement dates are in-line with the Company's public announcements. (2T 212) Those generation plant retirements will result in substantial obsolete inventory and the various plant retirement dates include River Rouge in 2020 and St. Clair and Trenton Channel both in 2023. (See Exhibit A-15, Statement G).[144]

[143] As noted above in the discussion of retirement dates, supra at n62, these dates are only "tentatively forecast" as indicated in Exhibit AB-1, page 1, making DTE's claim that the dates require recognition of obsolete inventory costs even less persuasive.
[144] See DTE reply brief, page 8.

For these reasons, this PFD concludes that DTE has failed to justify its proposed treatment of "obsolete inventory costs" as consistent with either the underlying depreciation method and underlying plant balances, or with the Commission's May 2016 Order. This PFD therefore recommends that the company's proposal not be adopted. This PFD further recommends that the Commission consider clarifying its May 2016 Order along the lines recommended by Staff, to provide that DTE may only charge obsolete inventory costs to the cost of removal when retirement is sufficiently imminent that DTE is taking steps to sell or transfer the remaining inventory.

E. Time value of money

As noted above, ABATE argues that the depreciation expense should recognize the time value of money. While the Commission has acknowledged the propriety of this principle, to date it has declined to apply this principle to depreciation calculation methodologies.

In its June 26, 2007 order in Case No. U-14292, the Commission addressed the new Statement of Financial Accounting Standards (SFAS) No. 143 issued by the Financial Accounting Standards Board. This standard discusses financial accounting and reporting for obligations related to the retirement of tangible long-lived assets and the associated asset retirement costs where there is a legal obligation to remove the asset. In its order, the Commission also acknowledged problems regarding cost of removal depreciation rates, including the failure to take into account the time value of money:

> The Commission agrees with the Staff, the Attorney General, and ABATE that there are apparent problems with the current method for calculating future cost of removal expense as demonstrated by the significant (and increasing) cost of removal depreciation expense accruals for several

> utilities. . . . . The Commission also agrees with the Staff that the more radical approaches proposed by the Attorney General and ABATE are problematic because of their potential effects on utility revenues.
>
> * * *
>
> The Commission likewise agrees that the current practice of calculating cost of removal ratios, by comparing removal costs in today's dollars with the original cost of the plant being retired, is no longer suitable. As the Staff observed, the first problem with this approach is that it assumes that past, generally higher inflation rates will continue into the future. Second, the traditional method fails to take into account the time value of money. As Mr. Aldrich explained:
>
>> If a utility incurs an obligation to expend $200 in 20 years, the utility would not record a liability of $200 on its books this year. Instead, under GAAP, the utility would record the net present value of that $200 future obligation, or $52 if an interest rate of 7% is used. The utility would then increase the liability at 7% per year over 20 years, resulting in a liability of $200 at the end of 20 years. However, this is not how the current cost of removal methodology works. Instead, the same $200 is expensed and collected from customers ratably over 20 years at $10 per year, a methodology that overcharges customers in the early years, and undercharges customers in the later years as compared to the net present value approach mandated by SFAS 143 for asset retirement obligations. By ignoring the time value of money, the current cost of removal methodology violates the principle of intergenerational equity.[145]

The Commission concluded that, "[w]hile the proposal to adjust historic inflation does not address the time value of money issue in calculating future removal costs", it agreed that "an SFAS No. 143 approach applied to required ARO and other ARO accounts would be informative, even if the Commission determines that SFAS No. 143 should not be used for ratemaking." Thus, the Commission directed the large utilities to file new depreciation cases and to calculate cost of removal depreciation under several calculation methods including "an SFAS No. 143 approach that considers the time value of money applied to required AROs and other AROs "in order that the Commission

[145] See June 26, 2007 order, pages 32-33.

could "assess the propriety of the different proposals and the efficacy of implementing them for each individual utility."[146]

In subsequent depreciation cases, the Commission ultimately rejected proposed alternative depreciation calculation methods. In its September 29, 2009 order in Case No. U-15629, the Commission concluded as follows:

> The Commission agrees with Consumers and the Staff that continued use of the traditional, straight-line depreciation method, coupled with the use of the Staff's proposed SRUs on a going forward basis, is the most appropriate means of addressing future removal costs. As discussed by [Consumers' consultant] Mr. Watson in his rebuttal testimony, the net present value approach proposed by the Attorney General has been consistently rejected by most Commissions and does not comport with depreciation methods recommended by authoritative sources on depreciation accounting. The accrual for net salvage must be based on estimates of the future cost that will be incurred, not the removal cost at today's price level. Therefore, it is appropriate to ask current customers to pay for future costs of removal at inflated price levels, and, as Mr. Watson pointed out, the rate base offset compensates rate payers for the prior payment for the costs incurred by the utility. Finally, the Commission finds that the Attorney General's proposed method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations. This, in turn, has a negative financial effect on both the utility and its customers by requiring that such obligations be met with more expensive sources of external financing and by driving up the cost generally of obtaining money in the capital markets. The Commission finds that the Attorney General has not shown that the adoption of the net present value method would justify these increased costs for utility consumers.[147]

Similarly, in its March 18, 2010 order in Case No. U-15699, addressing Consumers Energy's application for revised depreciation rates, the Commission explained:

> The Commission agrees with the Staff that continued use of the traditional, straight-line depreciation method, coupled with the use of the Staff's proposed SRUs on a going-forward basis, is the most appropriate means of addressing Mich Con's future removal costs. As discussed by [Mich Con witness] Dr. White in his rebuttal testimony, neither the Attorney General nor ABATE offered a better method for allocating future net

[146] See June 26, 2007 order, page 33.
[147] See September 19, 2009 order, page 12.

> salvage than the traditional straight-line method, and the Commission agrees that the simplicity of the traditional method far outweighs the complexity of attempting to change to either of the methods proposed by the Attorney General or ABATE.[148]

In this case, Mr. Andrews again recommended that the depreciation expense recognize the time value of money:

> Current policy does not give customers the benefit of the time value of money; the only benefit is given to utilities, including DTE. The current procedure, in the simplest terms, is to estimate the decommissioning cost in today's dollars, inflate those costs to a future retirement year, then divide the inflated cost estimate evenly over the remaining life of a power plant. Under this procedure, customers in year 1 would pay the exact same dollar amount as the customers in year 10 or 20 or 50. Although this calculation is performed every time the depreciation rates are updated, the assumption remains that an inflated cost estimate is evenly divided over the remaining life of the asset. Current customers are given no benefit for the time value of money, even though the value of a dollar now is greater than the value of a dollar at any point in the future if inflation is above 0%.[149]

Mr. Andrews offered Exhibit AB-2 to demonstrate that the time value of money is not properly reflected in the annual accrual of decommissioning costs, and which includes a methodology to determine a "time value of money adjustment" that will result in DTE collecting enough to meet the projected decommissioning cost estimate "but in a manner that more fairly allocates costs across generations of customers."[150] While acknowledging DTE's arguments that the Commission has previously approved a straight-line method for future removal costs, that "simplicity overcomes a more complicated method for calculating the cost of future removal", and that "any reduction

[148] See March 18, 2010 order, pages 11-12. The Commission's Order noted: "According to Dr. White, although considering the time value of money in accruing for net salvage is not a flawed concept, it was his opinion that the traditional approach was fair to both current and future ratepayers." Order, page 2.
[149] See Tr 190.
[150] See Tr 191.

in utility revenues as a result of reflecting the time value of money credit to customers would have negative financial consequences", ABATE argues as follows:

> When deciding this issue, the Commission should keep in mind that depreciation has two disparate impacts on customers and the utility. For customers, depreciation is an annual cash expense that is paid by customers to the utility. For a utility, this is a non-cash expense because there is no corresponding cash payout by the utility in the year in which the dollars are received. Instead, DTE simply credits the amounts received by customers to its depreciation reserve, which becomes a current asset offset by a future speculative liability. Utilities are free to use the free cash received from customers in a manner in which they choose prior to the time when the actual expenses are incurred many years in the future. Therefore, if the dollars collected from customers calculated using an adjustment for the time value of money are sufficient to meet the utility's future decommissioning expenses, then the Commission should approve the methodology which results in customers paying less up-front for depreciation expense. In the event that cost estimates change, the utilities can do what they do currently, and that is, request future adjustments in the amounts that are needed to pay for decommissioning costs. Obviously, any future projections are extremely speculative, so the Commission should adopt a policy that compensates utilities such as DTE for the just and reasonable cost of decommissioning while, at the same time, minimizing the current payments made by customers to utilities to cover depreciation expense.[151]

Through Mr. Cooper's rebuttal testimony and in its briefs, DTE points out that the Commission has rejected ABATE's suggested approach in three prior cases and thus should do so again here. Mr. Cooper testified that the traditional straight-line method previously approved by the Commission is the most appropriate method for calculating depreciation rates.[152]

This PFD finds that the Commission has repeatedly rejected ABATE's proposed modification of the net salvage method and ABATE has not provided a compelling basis for that determination to be reconsidered. As the Commission explained, the required calculations introduce additional complexity, and the contributions made by current

[151] See ABATE brief, pages 9-10 (emphasis in original).
[152] See Tr 168-169.

customers are reflected in the accumulated depreciation and thus reduce rate base in successive rate cases. This recommendation, however, is premised on this PFD's recommendation in section C above that the Commission reject DTE's proposed five-year escalation of removal costs from the projected date of retirement. As noted above, should the Commission adopt a method that increases the projected cost of removal by over 10% based on the additional five-year escalation, it may want to reconsider the intergenerational inequities identified by ABATE.

F. Land value

Mr. Andrews also recommended that the Commission consider the value of the land associated with retiring plants as an offset to removal costs. He explained:

> It is improper to ignore the land value for several reasons. First, if the site is actually brought to either Greenfield or Brownfield status, it will have significant value to a land developer. The sale of the land at the end of decommissioning should be treated as gross salvage and an offset to the cost of removal, similar to the treatment of net salvage for interim retirements. Second, because the sites already have the existing infrastructure and permits, they are most valuable to be utilized again for the next generation of power plants. If DTE builds its next generation of power plants at these same sites and ignores the value of land in the determination of net salvage rates, then current customers would both be providing revenues to DTE for expenses that are not completely expended, and also subsidizing the next generation of customers. In this scenario, the current and previous generations, would have paid for all improvements that can be reused for future power plants. This practice would decrease cost of service for future generations of customers at the expense of current customers.[153]
>
> Further, in some instances, DTE could sell the retired plant and the land prior to the final decommissioning, thus removing any and all liabilities with the site, and avoid expending decommissioning costs at all. This is exactly what occurred with DTE's Marysville plant. When DTE issued its Request for Proposal ("RFP") in April 2012 to demolish the Maryville plant, with an option to buy the site as-is, it selected the bidder that wished to purchase the site as-is. DTE was able to sell the site, without having to pay for demolition costs, and receive positive cash flow. DTE has also received

[153] See Tr 186.

> three purchase offers, for its Harbor Beach plant, yet is still attempting to recover estimated and escalated decommissioning costs for this plant. This is discussed in DTE's Exhibit A-12. Allowing current customers to provide revenues to DTE for estimated decommissioning costs without any consideration of the land value creates significant intergenerational inequities. [154]

In his rebuttal testimony for DTE, Mr. Cooper disagreed, characterizing Mr. Andrews' testimony as "purely speculative" and without basis in "historical or reasoned or accounting or depreciation practice", and reasoning as follows:

> First, land is a non-depreciable asset. As a result, the sale of land has no impact on depreciation rates. When land is sold, the transaction results in the recognition of a gain or loss depending on whether the land's value has increased or decreased since it was purchased. DTE Electric follows Plant Instruction 7, Paragraph E of the Uniform System of Accounts which states "Any difference between the amount received from the sale of land or land rights, less agents' commissions and other costs incident to the sale, and the book cost of such land or rights shall be included in Account 411.6, Gains from Disposition of Property or 411.7, Losses from Disposition of Utility Plant when such property has been recorded in account 105, Electric Plant Held for Future Use, otherwise to account 421.1 Gain on Disposition of Property or 421.2, Loss on Disposition of Property as appropriate…" The entry has no impact on depreciation rates or depreciation reserves. This contrasts with the accounting treatment for depreciable assets where, upon retirement, any salvage amounts collected for the remaining value of the asset are credited to the depreciation reserve and will have the impact of reducing depreciation rates.[155]

Similar to the issue regarding recognition of the time value of money, in Detroit Edison's prior depreciation case, U-16117, the Commission rejected ABATE's arguments that the value of demolished property should be considered in determining net salvage costs. In that case, Detroit Edison sought a 20% contingency factor for its demolition costs. ABATE challenged the 20% contingency, including suggesting that the

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[154] See Tr 186-187.
[155] See Tr 162-163.

20% contingency "be offset by the production site value of the demolished property."[156] While the Commission concluded that "Detroit Edison's proposed contingency was not supported on the record and that the ratepayers should not be burdened by excessive depreciation expense", the Commission added that it "is not persuaded that the contingency should be offset by the value of the resulting production site."[157]

In previously asserting that the value of the production sites should reduce the utility's net salvage expense, ABATE made arguments similar to those it makes in this case:

> Mr. Selecky testified that an existing production site is valuable because it has access to electric transmission lines, water supplies, and transportation networks, and already has environmental permits. The value of an already-improved site is considerably higher than typical raw land.
>
> Additional value is added for future deployment of generation because the site already has the appropriate zoning and approved land use for a generator. According to Mr. Selecky, this benefit should be retained by current customers who are paying for these plants, and should not be passed on blindly to future ratepayers. As a result, current depreciation rates should be reduced to reflect the value of the sites that will be available to future ratepayers.[158]

ABATE also pointed out that "other jurisdictions have recognized the value of existing sites", referencing commission and court rulings from Colorado, Missouri, Kansas and Texas.[159] In his PFD, ALJ Eyster addressed ABATE's assertions as follows**:**

> ABATE makes an alluring argument that the post-demolition value of these sites should be reflected in the Demolition Study. However, ABATE fails to present evidence from which an estimate of this value can be made. Additionally, there is no link between the post-demolition value of

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[156] See June 16, 2011 order, page 12.
[157] *Id*.
[158] See Case No. U-16117, January 14, 2011 ABATE Brief (Docket No. 47), pages 6-7 (citations omitted).
[159] *Id*. at pages 7-8 (quotations and citations omitted).

> the sites and the contingency factor and/or escalation rates. Therefore, ABATE's recommended adjustments are not adopted.[160]

This PFD thus finds that the Commission has previously rejected incorporating a review of the potential sale of land into the cost of removal and ABATE has not provided a compelling justification for the Commission to revisit its prior rulings. On this basis, this PFD recommends that the Commission reject ABATE's proposal.

By declining to consider the property values as offsetting the cost of removal, however, it should be noted that the Commission did not foreclose consideration of sales of property in future rate cases, consistent with the specific circumstances surrounding the investment in or improvement of the property. In Case No. U-5108, the Commission addressed the issue of the allocation of the gain on the sale of utility property in a Detroit Edison rate case as follows:

> The staff originally proposed an addition of $279,000 to applicant's income on account of a sale of Birmingham property. The staff conceded that the amount should be reduced to $121,000 to reflect the five-year average of miscellaneous transactions for the period 1971–75. The Birmingham property was in the rate base and the customers have paid a return on it.
>
> Applicant objected to the inclusion of the five-year average of $121,000, including gain from the sale, on the grounds that the gain from the sale was extraordinary and that accordingly the ratepayers should not benefit from it.
>
> The ALJ recommended that the $121,000 be included as income, and applicant excepted.
>
> *Since applicant's customers were charged for the property while it was in the rate base, they should receive the benefit of the gain on the sale.* The commission accordingly finds that the staff's proposed addition of $121,000 to income, which reflects the sale of the Birmingham property, is reasonable and should be adopted in this proceeding.

[160] See Case No. U-16117, March 24, 2011 PFD (Docket No. 53), page 32.

The Commission also recognized a sharing of the benefit from the sale of utility property in Case No. U-14701-R. In that case, Consumers sought approval to apportion the gain on the sale of various parcels of land adjoining its Ludington Pumped Storage Generating Plant 50/50 between the company and the ratepayers, providing a $2,370,000 offset to 2006 power supply recovery costs.[161] The Attorney General and the Michigan Environmental Council and the Public Interest Research Group in Michigan objected to the allocation, arguing that because ratepayers have borne all capital costs relating to these parcels for the past 30 years, ratepayers should receive all of the gain from the sale. ALJ Cummins rejected these arguments and recommended approval of the allocation of the sale gains on a 50/50 basis, finding that "under basic ratemaking principles, real property is not a depreciable asset whose purchase price is recoverable through base rates." In its April 22, 2008 order, the Commission adopted the ALJ's recommendation, concluding that "[t]he excess land was an asset shared by ratepayers and shareholders, and an equal sharing of the gain is appropriate."[162]

G. <u>Staff alternate proposals to set depreciation expense levels only</u>

Based on the concerns stated by Mr. Ancona, including the change in retirement dates, the inclusion of obsolete inventory, and the inflation of net salvage values to a date five years after the tentative retirement dates, Staff recommends that the Commission increase depreciation expense by the company's measurement of the difference between the recorded reserve and theoretical reserve, but not increase the depreciation rates to reflect the other results of Dr. White's depreciation study and the Sargent & Lundy decommissioning study. Mr. Ancona based his recommendation on

[161] See April 22, 2011 order, Case No. U-14701-R, page 13.
[162] See order, page 14.

his concerns with the revised retirement dates, the treatment of inventory costs, and the additional five-year escalation of removal costs:

> DTE witness Ronald White summarizes the effect of DTE's filing by stating: "The proposed 2016 expense increase is $156,384,755. The computed change in annualized accruals includes an increase of $39,218,444 attributable to an amortization of a $410,160,454 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistic recommended in the 2016 study." Exhibit S-1 shows DTE Electric's Depreciation Reserve has not been keeping pace with Plant in Service over the last ten years. This being the case, the increase attributable to the reserve imbalance seems reasonable. However, due to the concerns stated above, Staff recommends any increase in accrual rates be limited to the reserve imbalance increase at this time.[163]

DTE objected to Staff's proposal to set the depreciation expense level to recover only the reserve imbalance of $39.2 million as measured by DTE. Dr. White provided rebuttal testimony, reviewing the derivation of the $39.2 million depreciation expense increase Staff recommended. He testified that the theoretical or computed reserve reflects what the recorded depreciation reserve would be if and only if the timing of future retirements and realized net salvage occurred exactly as predicted by the survivor curves specified, while the reserve imbalance is the difference between the theoretical reserve and a recorded reserve at a given date. He testified that the $39.2 million reserve imbalance he calculated, which Staff incorporated in its recommendation, is therefore based on the service lives and net salvage values used in his study:

> Given that Staff found that "… the increase [in accruals] attributable to the reserve imbalance seems reasonable," it is illogical to argue that the remaining portion of the change in accruals "attributable to adjustments in service life and net statistics" is unreasonable. Clearly, adjusting service lives and/or net salvage rates to achieve an increase in depreciation

[163] See Tr 213.

> expense no greater than $39.2 million would change the reserve imbalance Staff found to be reasonable.[164]

He further characterized Staff's recommendation as "results driven," and cautioned: "I would strongly discourage using a change in depreciation expense as the barometer for assessing the adequacy or inadequacy of competently derived depreciations rates."[165]

Mr. Andrews also presented rebuttal testimony on Staff's proposal:

> My major concern with Mr. Ancona's testimony is his conclusion that any increase in accrual rates be limited to the reserve imbalance. On the surface, this may seem like a reasonable suggestion; however, this suggestion would require implicit agreement with DTE's entire proposal. Mr. Ancona has stated three major concerns with DTE's filing. These three concerns are: (i) the retirement dates assumed for St. Clair, River Rouge and Trenton Channel, (ii) the additional five years of escalation of dismantling cost estimates, and (iii) the inclusion of obsolete inventory amounts in deprecation rates for plants not yet retired. If Staff's concerns with these three items are remedied, the reserve imbalance would be significantly different from the $410 million that Dr. White has presented in testimony.[166]

In its brief, Staff does not directly address Dr. White's rebuttal testimony, but presents an alternate recommendation should the Commission accept the retirement dates DTE used. Under the alternate recommendation, if the Commission approved DTE's IRP in Case No. U-18419, Staff recommends an increase in depreciation expense of $65,508,120. Staff indicates that this revised depreciation expense figure includes escalated retirement dates for River Rouge, St. Clair, and Trenton Channel, but not Belle River, Monroe, or Greenwood because "presumed retirement dates for both the current and proposed scenarios are farther in the future and do not need to be addressed in this case."[167] Staff also indicates that the revised depreciation expense

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[164] See Tr 136.
[165] See Tr 137.
[166] See Tr 200.
[167] See Staff brief, page 4.

figures remove DTE's obsolete inventory expense projections and the additional five-year escalation from the removal cost calculations. In its reply brief, DTE disputes Staff's adjusted figures, contending that by adjusting Staff's approach to include Monroe, Belle River, and Greenwood, depreciation expense increases to $101,141,699, which DTE characterizes as "far more reasonable."[168] DTE also objects that Staff's calculations exclude the obsolete inventory amounts and additional five-year escalation of removal costs.

A review of the record in this case, as discussed above, shows that DTE presented relatively little support in its filing for the substantial adjustments to the current depreciation rates and corresponding expense level, and relies substantially on its rebuttal testimony in response to the objections raised by the other parties. Nonetheless, while acknowledging Staff's frustration with what this PFD concluded above were unsupported proposals, this PFD recommends that the Commission retain the traditional remaining-life method for setting depreciation rates by plant account, rather than setting only a depreciation expense allowance.

H. <u>Other undisputed issues</u>

No party disputed DTE's request to use the broad-group rather than vintage-group remaining-life procedure due to the lack of the data specified by the Commission in Case No. U-16117, although Staff proposed an alternative to the overall remaining-life method as discussed above. Likewise, no party disputed DTE's request to create a new account (Account 363) for storage battery equipment, or to switch to amortization for Account 397 (Communication Equipment).[169] No party disputed DTE's request to

[168] See DTE reply brief, page 5.
[169] See Tr 154-155.

revise the accounts and depreciation rates for various lighting assets as explained in Mr. Johnston's testimony.[170] And no party disputed DTE's opposed depreciation rates for the Midwest Energy Resources Company (MERC).[171] In the absence of dispute, this PFD finds that the requests should be granted.

I. Revised Depreciation Rates

In order to reflect the adjustments recommended above, or as otherwise determined by the Commission in its final order in this case, this PFD recommends that the Commission direct DTE to file revised calculations consistent with that order and following the approved method, with an opportunity for the revised calculations to be reviewed by all parties, rather than attempting the complex adjustments based on charts included in the briefs of the parties.

As discussed above in section G, this PFD recommends that the Commission set specific depreciation rates based on the remaining-life method used by Dr. White, rather than setting only depreciation expense levels for future rate cases. Providing for DTE to make a revised filing reflecting the Commission's decisions on the key issues identified above is also consistent with Dr. White's objections to Mr. Andrews' revised depreciation rate calculations.[172] ABATE explicitly addressed Dr. White's critique only in its reply brief, arguing that Mr. Andrews used the best information available.[173] This PFD finds that the goals of accuracy and efficiency would be best served by a revised filing using the data base and conventions reflected in Dr. White's Exhibit A-6, with

[170] See Tr 84-89.
[171] See Cooper, Tr 156.
[172] See Tr 130-134.
[173] See ABATE reply brief, page 4.

adjustments to the retirement dates and removal costs as reflected in the Commission's final order in this case.

There is also a question as to when DTE should file an updated depreciation study. Consistent with the discussion in section A above, this PFD recommends that DTE be required to file revised depreciation rates within 5 years if the Commission approves the proposed retirement dates in Case No. U-18419 and incorporates those retirement dates into its decision in this case, and within 2 years if the Commission defers approval to its review of the IRP filing anticipated in 2019 in accordance with the Commission's December 20, 2017 order in Case No. U-18461.

IV.

CONCLUSION

Based on the findings and conclusions set forth above, this PFD recommends that the Commission adopt the method and assumptions incorporated in DTE's depreciation study, with the following modifications:

1. The Commission should use the retirement dates for the River Rouge, St. Clair, Trenton Channel, and Belle River plants as reflected in DTE's IRP in Case No. U-18419 if it approves that IRP in its final order in that case and should use the retirement dates used in Case No. U-16117 if it does not approve DTE's IRP in that docket.

2. The Commission should reject DTE's proposal to include projected Harbor Beach and Conner's Creek removal costs with the River Rouge removal costs.

3. The Commission should reject DTE's proposed estimate and treatment of obsolete inventory costs as unsupported and inconsistent with the Commission's May

2016 Order, and provide clarification indicating that obsolete inventory costs should not be recovered through depreciation rates until they can be ascertained with greater specificity than permitted by DTE's generic approach in this case, for example when DTE determines that retirement is sufficiently imminent that DTE is taking steps to sell or transfer the remaining inventory.

4. The Commission should reject DTE's proposed additional five-year escalation of removal costs as unsupported on this record both methodologically and factually.

5. The Commission should reject ABATE's proposed recognition of the time value of money as an unnecessary refinement of the removal cost method, consistent with the recommendation in paragraph 4 above.

6. The Commission should reject ABATE's proposed recognition of gain on the sale of land in the removal cost calculations on the basis that such determinations are more appropriate for a rate case.

7. The Commission should otherwise retain the remaining-life method that sets account-specific depreciation rates as set forth in Dr. White's depreciation study, rather than setting only a depreciation expense level.

8. The Commission should adopt the accounting changes recommended by DTE and not opposed by any party, as discussed in section III.H above.

In addition, This PFD recommends that DTE be directed to file revised depreciation rate calculations reflecting the foregoing recommendations, with an opportunity for Staff and ABATE to review the calculations. And this PFD recommends that the Commission direct DTE to file revised depreciation rates in five years if the Commission revises the retirement dates for the company's steam generating plants in accordance with approval of the company's IRP as filed in Case No. U-18419, or to file revised depreciation rates in two years, following review of its IRP in accordance with Case Nos. U-18418 and U-18461, if it does not revise the retirement dates from those used in Case No. U-16117.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sharon L. Feldman

Digitally signed by Sharon L. Feldman
DN: cn=Sharon L. Feldman, o=MAHS, ou=MAHS PSC, email=feldmans@michigan.gov, c=US
Date: 2018.04.17 14:46:08 -04'00'

Sharon L. Feldman
Administrative Law Judge

Issued and Served:
April 17, 2018

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

STATE OF MICHIGAN	)	
	)	
County of Ingham	)	Case No. U-18150
	)	

PROOF OF SERVICE

Meaghan Dobie being duly sworn, deposes and says that on April 17, 2018, she served a copy of the attached Proposal for Decision via email and/or first-class mail, to the persons as shown on the attached service list.

Meaghan Dobie

Meaghan Dobie

Subscribed and sworn to before me
this 17th day of April 2018.

Lisa Felice

Lisa Felice
Notary Public, Eaton County
My Commission Expires April 15, 2020

Service List
Case No. U-18150

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Exhibit Bunch 12

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

November 18, 2009

Via e-filing and US Mail

Vikie Bailey-Goggins
Administrator
Oregon Public Utility Commission
550 Capital Street, N.E., Ste 215
Salem, Oregon 97310

Re: UM-1233 – Detailed Depreciation Study of Electric Utility Properties (OPUC Order No. 06-581, and as amended Order No. 07-438)

Dear Ms. Bailey-Goggins:

Pursuant to OPUC Order No. 06-581 on 10/13/2006, and as amended, Order No. 07-438 on 10/11/2007, Portland General Electric (PGE) submits the attached results of a detailed depreciation study of the electric properties of PGE as of December 31, 2008. PGE's last study, Docket UM-1233, was based upon data as of December 31, 2004, and filed on October 17, 2005. Depreciation rates were effective January 17, 2007.

PGE requests that the Commission approve the results of this study so that the new depreciation rates can be implemented in PGE's upcoming General Rate Case filing, which we expect to file in the first quarter of 2010. PGE proposes that depreciation rates recommended not be implemented until incorporated into general prices, which should be January 1, 2011. This study is filed one year in advance of the due date in OPUC Order 06-581 in order that effective depreciation rates coincide with the revenue requirements of the 2011 General Rate Case.

This study includes an analysis of all primary plant accounts at all locations. All assets in PGE's traditional FERC classification of generation, transmission, distribution and general plant assets are included in the study.

This depreciation study recommends revisions in depreciation lives, curves and salvage rates for all plant accounts, and a revision to life span from average remaining life methodology for its wind generation plant assets.

The Oregon Regional Haze Plan (Plan) and Oregon Utility Mercury Rule (Rule) requirements at the Boardman coal plant caused PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing plant operations and replacing the Boardman coal plant with a new source of supply.

and the current balance in the account is very small. However, there may be projects initiated in the future which could result in additional plant balances being added to this account. PGE continues to explore customer based solutions, both energy efficiency and demand response actions, as effective ways to meet some of our energy and capacity requirements. We are increasing our focus on demand-side resources by pursuing several new ideas and initiatives to acquire, expand or enable future customer-based solutions. Potential demand response projects include air-conditioning cycling and water heater switches to foster changes in consumption during critical peak usage times.

Initially, it is anticipated that demand response projects would be small scale and exploratory in nature. It is recommended that a 10 year life and 0 percent net salvage rate be utilized for these types of costs. If the activity grows in future years, statistics and recommendations will be revised in later depreciation studies.

Recommended curve and life R3 10

Recommended depreciation rates: 2011-2015

371:
Non-specific locations 33.333%

Recommended net salvage rate 0

Account 37301 - Streetlighting and Signal Systems
- Circuits other than Portland

Average Service Life

Simulation L2 37

Currently prescribed L0 43

Account 37301, a sub-account of the Streetlighting and Signal Systems account, contains circuits for areas other than the City of Portland. Since Accounts 365 and 37301 contain the similar assets, data for these accounts have been grouped together for life study purposes for many years. Retirement data has been maintained in the depreciation module for this account since 2000, and the account will be analyzed on its own merits in the next depreciation study. But for purposes of this study, PGE recommends an L2 37 for 37301, the same as recommended for Account 365.

Recommended curve and life L2 37

Recommended depreciation rates: 2011-2015

37301:	
Non-specific locations	4.750%

	Salvage
Study average 2000 – 2008	-275
Currently prescribed	-70

PGE is currently prescribed a net salvage rate of -70 percent for Account 37301. Retirement statistics have been maintained for this account since 2000. For the time period from 2000 through 2008, the net salvage experience has been highly negative, -275 percent. In the period since the last study, however, the rate eased somewhat, averaging -94 percent. Shrinking band analysis indicates that the most recent trend is toward somewhat lower net salvage values than the weighted averages. PGE recommends retention of its current net salvage rate of -70 for this account with gross salvage of 20 percent and cost of removal of 90 percent.

Recommended net salvage rate -70

Account 37302 - Streetlighting and Signal Systems - Fixtures, Ornamental Posts, and Devices

	Average Service Life
Simulation	L0 24
Currently prescribed	L1 21

PGE currently has a prescribed dispersion and average life of L1 21 for Account 37302, Streetlights and Signal Systems -Fixtures, Ornamental Posts, and Devices. Simulation results have ranged from 18 to 21 years since 1980. In the most recent study, the results were consistent with historical data, a best fitting curve-life combination of L0 24. The industry average for Account 373 is 28 years, with a range from 17 to 50 years. PGE recommends moving to the results of the most recent analyses for this streetlight account.

Recommended curve and life L0 24

Recommended depreciation rates: 2011-2015

37302:	
Non-specific locations	8.163%

Salvage

Study average 1971 – 2008	-50
Currently prescribed	-70

PGE currently has a prescribed net salvage rate of -70 percent for Account 37302. Prior to 1983, net salvage was positive each year. Since 1983, however, with the exception of two years, all experience has been highly negative. The cumulative average net salvage rate is -50 percent, with an average of -123 percent in the past 10 years, and -100 percent in the past 5 years. In the latest three years, however, the high negative salvage rates have eased somewhat, averaging -70 percent. Based on the most recent activity, PGE recommends retaining the net salvage rate of -70 percent for this account, including a gross salvage rate of 20 percent and cost of removal rate of 90 percent.

Recommended net salvage rate -70

Account 37307 - Streetlighting and Signal Systems
- Sentinel Lighting Equipment

Average Service Life

Simulation	L0 22
Currently prescribed	L0 20

PGE currently has a prescribed curve and life combination of L0 20 for Account 37307. Simulation results for the sentinel light account have ranged from 15 to 22 years since 1975, with a best fitting curve-life combination of L0 22 in the most recent study. Since the statistical results have been so consistent over the years, it is recommended that the most recent simulation best-fitting curve-life combination of L0 22 be adopted.

Recommended curve and life L0 22

Recommended depreciation rates: 2011-2015

37307:
Non-specific locations 9.009%

	Salvage
Study average 1971 – 2008	-70
Currently prescribed	-70

A net salvage rate of -70 percent is currently prescribed for Account 37307. Net realized salvage for sentinel lights has been negative since 1977, with the exception of positive years in 1983 and 1984. Since 1984, the cost of removal has been high with negligible salvage dollars. The weighted average net salvage ratio is -70 percent, with an average of -107 percent in the past 10 years and -70 in the past 5 years. The statistics for the most recent five year period support the net salvage rate of -70 percent currently prescribed. Retention of the net salvage rate of -70 percent, with gross salvage of 15 percent, and cost of removal of 85 percent is recommended for the sentinel light account.

Recommended net salvage rate	-70

Exhibit Bunch 13

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 199

Responding Witness: Valerie L. Scott

Q-199. Provide the current depreciation rates, split into three separate components: capital recovery, gross salvage, and cost of removal.

A-199. See attached.

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
ELECTRIC PLANT				
Intangible Plant	0.00%	0.00%	0.00%	0.00%
Steam Production Plant				
310.20 Land	0.00%	0.00%	0.00%	0.00%
311.00 Structures and Improvements				
0112 Cane Run Unit 1	0.00%	0.00%	0.00%	0.00%
0121 Cane Run Unit 2	0.00%	0.00%	0.00%	0.00%
0131 Cane Run Unit 3	0.00%	0.00%	0.00%	0.00%
0141 Cane Run Unit 4	0.00%	0.00%	0.00%	0.00%
0142 Cane Run Unit 4 FGD	0.00%	0.00%	0.00%	0.00%
0151 Cane Run Unit 5	0.48%	0.47%	0.01%	0.00%
0152 Cane Run Unit 5 FGD	0.00%	0.00%	0.00%	0.00%
0161 Cane Run Unit 6	6.99%	6.85%	0.14%	0.00%
0162 Cane Run Unit 6 FGD	0.00%	0.00%	0.00%	0.00%
0211 Mill Creek Unit 1	0.97%	0.90%	0.07%	0.00%
0212 Mill Creek Unit 1 FGD	0.00%	0.00%	0.00%	0.00%
0221 Mill Creek Unit 2	0.99%	0.92%	0.07%	0.00%
0222 Mill Creek Unit 2 FGD	0.00%	0.00%	0.00%	0.00%
0231 Mill Creek Unit 3	0.95%	0.88%	0.07%	0.00%
0232 Mill Creel Unit 3 FGD	0.00%	0.00%	0.00%	0.00%
0241 Mill Creek Unit 4	1.65%	1.53%	0.12%	0.00%
0242 Mill Creek Unit 4 FGD	0.50%	0.46%	0.04%	0.00%
0311 Trimble County Unit 1	1.59%	1.43%	0.16%	0.00%
0312 Trimble County Unit 1 FGD	1.01%	0.91%	0.10%	0.00%
0321 Trimble County Unit 2	2.10%	1.89%	0.21%	0.00%
312.00 Boiler Plant Equipment				
0103 Cane Run Locomotive	0.00%	0.00%	0.00%	0.00%
0104 Cane Run Rail Cars	6.89%	6.89%	0.00%	0.00%
0112 Cane Run Unit 1	0.00%	0.00%	0.00%	0.00%
0121 Cane Run Unit 2	0.00%	0.00%	0.00%	0.00%
0131 Cane Run Unit 3	0.00%	0.00%	0.00%	0.00%
0141 Cane Run Unit 4	7.66%	7.51%	0.30%	-0.15%
0142 Cane Run Unit 4 FGD	0.00%	0.00%	0.00%	0.00%
0151 Cane Run Unit 5	13.54%	13.28%	0.53%	-0.27%
0152 Cane Run Unit 5 FGD	0.00%	0.00%	0.00%	0.00%
0161 Cane Run Unit 6	13.69%	13.42%	0.54%	-0.27%
0162 Cane Run Unit 6 FGD	3.70%	3.62%	0.15%	-0.07%
0203 Mill Creek Locomotive	6.08%	6.08%	0.00%	0.00%
0204 Mill Creek Rail Cars	0.36%	0.36%	0.00%	0.00%
0211 Mill Creek Unit 1	2.53%	2.35%	0.23%	-0.05%
0212 Mill Creek Unit 1 FGD	1.76%	1.63%	0.16%	-0.03%
0221 Mill Creek Unit 2	2.84%	2.63%	0.26%	-0.05%
0222 Mill Creek Unit 2 FGD	1.40%	1.30%	0.13%	-0.03%
0231 Mill Creek Unit 3	2.64%	2.45%	0.24%	-0.05%
0232 Mill Creel Unit 3 FGD	2.17%	2.01%	0.20%	-0.04%
0241 Mill Creek Unit 4	2.54%	2.35%	0.24%	-0.05%
0242 Mill Creek Unit 4 FGD	1.56%	1.45%	0.14%	-0.03%
0311 Trimble County Unit 1	2.54%	2.29%	0.30%	-0.05%
0312 Trimble County Unit 1 FGD	1.25%	1.12%	0.15%	-0.02%
0321 Trimble County Unit 2	2.46%	2.21%	0.29%	-0.04%
0322 Trimble County Unit 2 FGD	2.47%	2.22%	0.29%	-0.04%
314.00 Turbogenerator Units				
0112 Cane Run Unit 1	0.00%	0.00%	0.00%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
0121 Cane Run Unit 2	0.00%	0.00%	0.00%	0.00%
0131 Cane Run Unit 3	0.00%	0.00%	0.00%	0.00%
0141 Cane Run Unit 4	1.47%	1.44%	0.06%	-0.03%
0151 Cane Run Unit 5	0.83%	0.82%	0.03%	-0.02%
0161 Cane Run Unit 6	8.36%	8.19%	0.33%	-0.16%
0211 Mill Creek Unit 1	1.03%	0.95%	0.10%	-0.02%
0221 Mill Creek Unit 2	1.49%	1.38%	0.14%	-0.03%
0231 Mill Creek Unit 3	1.91%	1.77%	0.18%	-0.04%
0241 Mill Creek Unit 4	1.57%	1.45%	0.15%	-0.03%
0311 Trimble County Unit 1	2.18%	1.96%	0.26%	-0.04%
0321 Trimble County Unit 2	2.11%	1.90%	0.25%	-0.04%
315.00 Accessory Electric Equipment				
0112 Cane Run Unit 1	0.00%	0.00%	0.00%	0.00%
0121 Cane Run Unit 2	0.00%	0.00%	0.00%	0.00%
0131 Cane Run Unit 3	0.00%	0.00%	0.00%	0.00%
0141 Cane Run Unit 4	3.29%	3.22%	0.10%	-0.03%
0142 Cane Run Unit 4 FGD	0.00%	0.00%	0.00%	0.00%
0151 Cane Run Unit 5	11.22%	11.00%	0.33%	-0.11%
0152 Cane Run Unit 5 FGD	0.00%	0.00%	0.00%	0.00%
0161 Cane Run Unit 6	10.78%	10.57%	0.32%	-0.11%
0162 Cane Run Unit 6 FGD	0.00%	0.00%	0.00%	0.00%
0211 Mill Creek Unit 1	2.75%	2.55%	0.23%	-0.03%
0212 Mill Creek Unit 1 FGD	0.00%	0.00%	0.00%	0.00%
0221 Mill Creek Unit 2	1.78%	1.65%	0.15%	-0.02%
0222 Mill Creek Unit 2 FGD	0.00%	0.00%	0.00%	0.00%
0231 Mill Creek Unit 3	0.92%	0.85%	0.08%	-0.01%
0232 Mill Creel Unit 3 FGD	0.00%	0.00%	0.00%	0.00%
0241 Mill Creek Unit 4	1.49%	1.38%	0.12%	-0.01%
0242 Mill Creek Unit 4 FGD	0.38%	0.35%	0.03%	0.00%
0311 Trimble County Unit 1	2.00%	1.80%	0.22%	-0.02%
0312 Trimble County Unit 1 FGD	0.88%	0.79%	0.10%	-0.01%
0321 Trimble County Unit 2	2.29%	2.06%	0.25%	-0.02%
316.00 Miscellaneous Plant Equipment				
0112 Cane Run Unit 1	0.00%	0.00%	0.00%	0.00%
0131 Cane Run Unit 3	0.00%	0.00%	0.00%	0.00%
0141 Cane Run Unit 4	16.79%	16.46%	0.49%	-0.16%
0142 Cane Run Unit 4 FGD	0.00%	0.00%	0.00%	0.00%
0151 Cane Run Unit 5	15.39%	15.09%	0.45%	-0.15%
0152 Cane Run Unit 5 FGD	0.00%	0.00%	0.00%	0.00%
0161 Cane Run Unit 6	13.71%	13.44%	0.40%	-0.13%
0162 Cane Run Unit 6 FGD	0.00%	0.00%	0.00%	0.00%
0211 Mill Creek Unit 1	2.51%	2.32%	0.21%	-0.02%
0221 Mill Creek Unit 2	1.76%	1.63%	0.15%	-0.02%
0231 Mill Creek Unit 3	1.22%	1.13%	0.10%	-0.01%
0241 Mill Creek Unit 4	2.71%	2.51%	0.23%	-0.03%
0242 Mill Creek Unit 4 FGD	2.05%	1.90%	0.17%	-0.02%
0311 Trimble County Unit 1	2.47%	2.22%	0.27%	-0.02%
0321 Trimble County Unit 2	2.54%	2.29%	0.27%	-0.02%
Hydraulic Production Plant - Project 289				
0451 - Ohio Falls Project 289				
330.20 Land	0.00%	0.00%	0.00%	0.00%
331.00 Structures and Improvements	0.47%	0.46%	0.01%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
332.00 Reservoirs, Dams & Waterways	2.62%	2.54%	0.08%	0.00%
333.00 Water Wheels, Turbines and Generators	2.96%	2.88%	0.11%	-0.03%
334.00 Accessory Electric Equipment	2.01%	1.95%	0.06%	0.00%
335.00 Misc. Power Plant Equipment	2.63%	2.55%	0.08%	0.00%
336.00 Roads, Railroads and Bridges	2.26%	2.19%	0.07%	0.00%
Hydraulic Production Plant - Other Than Project 289				
0450 - Ohio Falls Other Than Project 289				
330.20 Land	0.00%	0.00%	0.00%	0.00%
331.00 Structures and Improvements	1.46%	1.42%	0.04%	0.00%
335.00 Misc. Power Plant Equipment	2.81%	2.73%	0.08%	0.00%
336.00 Roads, Railroads and Bridges	0.00%	0.00%	0.00%	0.00%
Other Production Plant				
340.20 Land	0.00%	0.00%	0.00%	0.00%
341.00 Structures and Improvements				
0171 Cane Run GT 11	13.86%	13.59%	0.27%	0.00%
0410 Zorn and River Road Gas Turbine	0.00%	0.00%	0.00%	0.00%
0431 Paddys Run Generator 12	3.23%	3.14%	0.09%	0.00%
0432 Paddys Run Generator 13	3.57%	3.47%	0.10%	0.00%
0459 Brown CT 5	3.57%	3.47%	0.10%	0.00%
0460 Brown CT 6	4.09%	3.97%	0.12%	0.00%
0461 Brown CT 7	4.08%	3.96%	0.12%	0.00%
5648 Brown Solar	4.24%	4.04%	0.20%	0.00%
0172 Cane Run CT 7	2.62%	2.62%	0.00%	0.00%
0470 Trimble County CT 5	3.58%	3.48%	0.10%	0.00%
0471 Trimble County CT 6	3.57%	3.47%	0.10%	0.00%
0474 Trimble County CT 7	3.52%	3.42%	0.10%	0.00%
0475 Trimble County CT 8	3.52%	3.42%	0.10%	0.00%
0476 Trimble County CT 9	3.53%	3.43%	0.10%	0.00%
0477 Trimble County CT 10	3.53%	3.43%	0.10%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
342.00 Fuel Holders, Producers and Accessories				
0171 Cane Run GT 11	14.18%	13.90%	0.28%	0.00%
0410 Zorn and River Road Gas Turbine	3.84%	3.73%	0.11%	0.00%
0430 Paddys Run Generator 11	0.00%	0.00%	0.00%	0.00%
0431 Paddys Run Generator 12	4.93%	4.79%	0.14%	0.00%
0432 Paddys Run Generator 13	3.70%	3.59%	0.11%	0.00%
0459 Brown CT 5	4.11%	3.99%	0.12%	0.00%
0460 Brown CT 6	5.40%	5.24%	0.16%	0.00%
0461 Brown CT 7	8.07%	7.83%	0.24%	0.00%
0172 Cane Run CT 7	2.73%	2.60%	0.13%	0.00%
0470 Trimble County CT 5	3.68%	3.57%	0.11%	0.00%
0471 Trimble County CT 6	3.68%	3.57%	0.11%	0.00%
0473 Trimble County CT Pipeline	3.35%	3.25%	0.10%	0.00%
0474 Trimble County CT 7	3.63%	3.52%	0.11%	0.00%
0475 Trimble County CT 8	3.63%	3.52%	0.11%	0.00%
0476 Trimble County CT 9	3.65%	3.54%	0.11%	0.00%
0477 Trimble County CT 10	3.66%	3.55%	0.11%	0.00%
343.00 Prime Movers				
0432 Paddys Run Generator 13	4.56%	4.42%	0.18%	-0.04%
0459 Brown CT 5	4.33%	4.20%	0.17%	-0.04%
0460 Brown CT 6	5.99%	5.82%	0.23%	-0.06%
0461 Brown CT 7	5.05%	4.90%	0.20%	-0.05%
0172 Cane Run CT 7	2.79%	2.66%	0.16%	0.00%
0470 Trimble County CT 5	4.37%	4.24%	0.17%	-0.04%
0471 Trimble County CT 6	4.49%	4.36%	0.17%	-0.04%
0474 Trimble County CT 7	4.03%	3.91%	0.16%	-0.04%
0475 Trimble County CT 8	4.03%	3.91%	0.16%	-0.04%
0476 Trimble County CT 9	4.08%	3.96%	0.16%	-0.04%
0477 Trimble County CT 10	4.08%	3.96%	0.16%	-0.04%
344.00 Generators				
0171 Cane Run GT 11	4.76%	4.67%	0.14%	-0.05%
0410 Zorn and River Road Gas Turbine	0.00%	0.00%	0.00%	0.00%
0430 Paddys Run Generator 11	0.00%	0.00%	0.00%	0.00%
0431 Paddys Run Generator 12	0.00%	0.00%	0.00%	0.00%
0432 Paddys Run Generator 13	3.26%	3.16%	0.13%	-0.03%
0459 Brown CT 5	3.61%	3.51%	0.14%	-0.04%
0460 Brown CT 6	3.79%	3.68%	0.15%	-0.04%
0461 Brown CT 7	3.84%	3.73%	0.15%	-0.04%
5648 Brown Solar	4.61%	4.39%	0.26%	-0.04%
0172 Cane Run CT 7	3.11%	2.83%	0.34%	-0.06%
0470 Trimble County CT 5	3.50%	3.39%	0.14%	-0.03%
0471 Trimble County CT 6	3.50%	3.39%	0.14%	-0.03%
0474 Trimble County CT 7	3.46%	3.36%	0.13%	-0.03%
0475 Trimble County CT 8	3.46%	3.36%	0.13%	-0.03%
0476 Trimble County CT 9	3.47%	3.37%	0.13%	-0.03%
0477 Trimble County CT 10	3.47%	3.37%	0.13%	-0.03%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
345.00 Accessory Electric Equipment				
0171 Cane Run GT 11	0.00%	0.00%	0.00%	0.00%
0410 Zorn and River Road Gas Turbine	0.00%	0.00%	0.00%	0.00%
0430 Paddys Run Generator 11	0.00%	0.00%	0.00%	0.00%
0431 Paddys Run Generator 12	13.71%	13.31%	0.40%	0.00%
0432 Paddys Run Generator 13	3.60%	3.50%	0.10%	0.00%
0459 Brown CT 5	3.60%	3.50%	0.10%	0.00%
0460 Brown CT 6	3.91%	3.80%	0.11%	0.00%
0461 Brown CT 7	3.94%	3.83%	0.11%	0.00%
5648 Brown Solar	4.36%	4.15%	0.21%	0.00%
0172 Cane Run CT 7	2.97%	2.83%	0.14%	0.00%
0470 Trimble County CT 5	3.70%	3.59%	0.11%	0.00%
0471 Trimble County CT 6	3.81%	3.70%	0.11%	0.00%
0474 Trimble County CT 7	3.56%	3.46%	0.10%	0.00%
0475 Trimble County CT 8	3.56%	3.46%	0.10%	0.00%
0476 Trimble County CT 9	3.57%	3.47%	0.10%	0.00%
0477 Trimble County CT 10	3.73%	3.62%	0.11%	0.00%
346.00 Miscellaneous Plant Equipment				
0410 Zorn and River Road Gas Turbine	13.22%	12.84%	0.38%	0.00%
0430 Paddys Run Generator 11	15.24%	14.80%	0.44%	0.00%
0432 Paddys Run Generator 13	3.72%	3.61%	0.11%	0.00%
0459 Brown CT 5	3.58%	3.48%	0.10%	0.00%
0460 Brown CT 6	3.84%	3.73%	0.11%	0.00%
0461 Brown CT 7	3.90%	3.79%	0.11%	0.00%
5648 Brown Solar	4.25%	4.25%	0.00%	0.00%
0172 Cane Run CT 7	2.82%	2.82%	0.00%	0.00%
0470 Trimble County CT 5	3.72%	3.61%	0.11%	0.00%
0474 Trimble County CT 7	3.50%	3.40%	0.10%	0.00%
0475 Trimble County CT 8	3.51%	3.41%	0.10%	0.00%
0476 Trimble County CT 9	3.51%	3.41%	0.10%	0.00%
0477 Trimble County CT 10	4.17%	4.05%	0.12%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
Transmission Plant				
350.2 Transmission Lines Land	0.00%	0.00%	0.00%	0.00%
350.1 Land Rights	1.50%	1.50%	0.00%	0.00%
352.1 Structures & Improvements	1.74%	1.66%	0.08%	0.00%
353.1 Station Equipment - Project 289	1.74%	1.66%	0.08%	0.00%
353.1 Station Equipment	1.38%	1.26%	0.16%	-0.04%
354 Towers & Fixtures	1.72%	1.15%	0.62%	-0.05%
355 Poles & Fixtures	2.89%	1.86%	1.12%	-0.09%
356.1 Overhead Conductors & Devices - Project 289	2.50%	1.79%	0.82%	-0.11%
356 Overhead Conductors & Devices	2.50%	1.79%	0.82%	-0.11%
357 Underground Conduit	1.67%	1.67%	0.00%	0.00%
358 Underground Conductors & Devices	2.98%	2.84%	0.14%	0.00%
Distribution Plant				
360.2 Substation Land	0.00%	0.00%	0.00%	0.00%
360.2 Substation Land Class A (Plant Held for Future Use)	0.00%	0.00%	0.00%	0.00%
361 Substation Structures	1.61%	1.46%	0.15%	0.00%
362.1 Substation Equipment	2.09%	1.81%	0.33%	-0.05%
362.1 Substation Equipment - Class A (Plant Held for Future Use)	0.00%	0.00%	0.00%	0.00%
364 Poles Towers & Fixtures	3.39%	2.00%	1.49%	-0.10%
365 Overhead Conductors &Devices	2.98%	1.86%	1.23%	-0.11%
366 Underground Conduit	1.50%	1.25%	0.25%	0.00%
367 Underground Conductors & Devices	1.92%	1.60%	0.32%	0.00%
368.1 Line Transformers	2.38%	1.98%	0.46%	-0.06%
368.2 Line Transformer Installations (Combined in 368)	2.38%	1.98%	0.46%	-0.06%
369.1 Underground Services	3.32%	2.37%	0.95%	0.00%
369.2 Overhead Services	3.59%	1.79%	1.80%	0.00%
370.1 Meters	2.92%	2.92%	0.00%	0.00%
370.2 Meter Installations (Combined in 370)	2.92%	2.92%	0.00%	0.00%
373.1 Overhead Street Lighting	3.97%	3.18%	0.79%	0.00%
373.2 Underground Streetlighting	3.44%	2.65%	0.79%	0.00%
General Plant				
392.0 Transportation Equip Cars & Light Trucks	5.48%	5.48%	0.00%	0.00%
392.1 Transportation Equip Heavy Trucks and Other	0.60%	0.60%	0.00%	0.00%
392.2 Transportation Equip Trailers	6.21%	6.54%	0.00%	-0.33%
394 Tools, Shop, and Garage Equipment	4.51%	4.51%	0.00%	0.00%
396.0 Power Operated Equip Large Machinery	2.12%	2.12%	0.00%	0.00%
396.1 Power Operated Equip Small Machinery	0.00%	0.00%	0.00%	0.00%
396.2 Power operated Equipment Other	7.60%	7.60%	0.00%	0.00%
397.2 DSM Equipment	13.14%	13.14%	0.00%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
GAS PLANT				
INTANGIBLE PLANT - Franchises and Consents	10.58%	10.58%	0.00%	0.00%
UNDERGROUND STORAGE				
350.1 Land	0.00%	0.00%	0.00%	0.00%
350.2 Rights of Way	0.56%	0.56%	0.00%	0.00%
351.2 Compressor Station Structures	2.01%	1.83%	0.18%	0.00%
351.3 Regulating Station Structures	1.14%	1.09%	0.05%	0.00%
351.4 Other Structures	1.82%	1.65%	0.17%	0.00%
352.40 Well Drilling	0.72%	0.60%	0.13%	-0.01%
352.50 Well Equipment	2.70%	2.25%	0.52%	-0.07%
352.1 Storage Leaseholds & Rights	0.00%	0.00%	0.00%	0.00%
352.2 Reservoirs	0.00%	0.00%	0.00%	0.00%
352.3 Nonrecoverable Natural Gas	0.83%	0.83%	0.00%	0.00%
Gas Stored Underground Non-Current	0.00%	0.00%	0.00%	0.00%
353 Lines	1.82%	1.66%	0.18%	-0.02%
354 Compressor Station Equipment	2.37%	2.26%	0.16%	-0.05%
355 Measuring & Regulating Equipment	1.53%	1.46%	0.10%	-0.03%
356 Purification Equipment	1.97%	1.72%	0.27%	-0.02%
357 Other Equipment	2.25%	2.14%	0.13%	-0.02%
TRANSMISSION PLANT				
365.2 Rights of Way	0.16%	0.16%	0.00%	0.00%
367 Mains	0.79%	0.72%	0.08%	-0.01%
DISTRIBUTION PLANT				
374 Land	0.00%	0.00%	0.00%	0.00%
374.2 Land Rights	0.00%	0.00%	0.00%	0.00%
375.1 City Gate Structures	1.46%	1.39%	0.07%	0.00%
375.2 Other Distribution Structures	5.26%	5.01%	0.25%	0.00%
376 Mains	1.89%	1.45%	0.47%	-0.03%
378 Measuring and Reg Equipment	2.58%	2.34%	0.26%	-0.02%
379 Meas & Reg Equipment - City Gate	2.12%	1.85%	0.31%	-0.04%
380 Services	3.79%	2.37%	1.42%	0.00%
381 Meters	4.03%	4.03%	0.00%	0.00%
382 Meter Installations (Combined with 381 Meters)	4.03%	4.03%	0.00%	0.00%
383 House Regulators	4.10%	3.73%	0.41%	-0.04%
384 House Regulator Installations (Combined with 383)	4.10%	3.73%	0.41%	-0.04%
385 Industrial Meas & Reg Station Equip	2.85%	2.71%	0.19%	-0.05%
387 Other Equipment	2.78%	2.78%	0.00%	0.00%
GAS GENERAL PLANT				
392.0 Transportation Equip Cars & Light Trucks	2.63%	2.63%	0.00%	0.00%
392.1 Transportation Equip Heavy Trucks and Other	1.75%	1.75%	0.00%	0.00%
392.2 Transportation Equip Trailers	4.80%	5.05%	0.00%	-0.25%
394 Tools, Shop, and Garage Equipment	4.66%	4.66%	0.00%	0.00%
396.0 Power Operated Equip Large Machinery	1.16%	1.16%	0.00%	0.00%
396.1 Power Operated Equip Small Machinery	0.00%	0.00%	0.00%	0.00%
396.2 Power operated Equipment Other	5.90%	6.21%	0.00%	-0.31%
397.2 DSM Gas	13.14%	13.14%	0.00%	0.00%

Louisville Gas and Electric Company
Current Depreciation Rates

Property Group	Composite Rates	Life Rates	COR Rates	Salvage Rates
COMMON UTILITY PLANT				
INTANGIBLE PLANT				
301 Organization	0.00%	0.00%	0.00%	0.00%
302 Franchises and Consents	0.00%	0.00%	0.00%	0.00%
303 Software	13.97%	13.97%	0.00%	0.00%
303.1 CCS Software	9.92%	9.92%	0.00%	0.00%
GENERAL PLANT				
389.1 Land	0.00%	0.00%	0.00%	0.00%
389.2 Land Rights	0.00%	0.00%	0.00%	0.00%
390.10 Structures and Improvements - BOC	3.40%	3.09%	0.31%	0.00%
390.10 Structures and Improvements - LG&E Building	3.40%	3.09%	0.31%	0.00%
390.10 Structures and Improvements - BOC (Actors)	3.40%	3.09%	0.31%	0.00%
390.10 Structures and Improvements	3.40%	3.09%	0.31%	0.00%
390.20 Structures and Improvements - Transportation	5.98%	5.70%	0.28%	0.00%
390.30 Structures and Improvements - Stores	1.96%	1.78%	0.18%	0.00%
390.40 Structures and Improvements - Shops	2.05%	1.95%	0.10%	0.00%
390.60 Structures and Improvements - Microwave	2.30%	2.19%	0.11%	0.00%
391.10 Office Furniture	19.94%	19.94%	0.00%	0.00%
391.20 Office Equipment	8.16%	8.16%	0.00%	0.00%
391.30 Computer Equipment - Non PC	3.43%	3.43%	0.00%	0.00%
391.31 Personal Computers	21.88%	21.88%	0.00%	0.00%
391.40 Security Equipment	18.18%	18.18%	0.00%	0.00%
392.0 Transportation Equip Cars & Light Trucks	11.38%	11.38%	0.00%	0.00%
392.1 Transportation Equip Heavy Trucks and Other	0.00%	0.00%	0.00%	0.00%
392.2 Trailers	6.34%	6.67%	0.00%	-0.33%
393 Stores Equipment	5.82%	5.82%	0.00%	0.00%
394 Tools, Shop, and Garage Equipment	5.04%	5.04%	0.00%	0.00%
396.0 Power Operated Equip Large Machinery	1.13%	1.13%	0.00%	0.00%
396.2 Power operated Equipment Other	6.57%	7.30%	0.00%	-0.73%
397 Communications Equipment Microwave, Fiber, Other	13.14%	13.14%	0.00%	0.00%
397.10 Comm. Equip. - Radios and Telephones	4.89%	4.89%	0.00%	0.00%

CASE NO. 2020-00349 AND CASE NO. 2020-00350
LEXINGTON-FAYETTE URBAN COUNTY GOVERNMENT
AND LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT

Exhibit Bunch 14

Question:

8. The following requests refer to streetlight service interruptions caused by failures of streetlight fixtures and other streetlighting equipment including support arms, poles and wiring. In your responses, please exclude outages caused by power service interruptions unless the interruption occurred only in a dedicated street lighting circuit.
   a. How many street light outages occurred in each of calendar years 2017, 2018 and 2019? How many street lights were affected by the outages in each of those years?
   b. What was the average duration of those outages, by calendar year, for 2017-2019?
   c. What was the average total annual outage time per fixture for 2017-2019, excluding power interruptions and excluding daylight hours?
   d. In reference to Company witness Blumenstock's direct testimony p. 93, "The Company targets replacement of cobra head streetlights within five days of a reported outage." How many outages reported in calendar years 2017, 2018 and 2019 lasted longer than five days? Please provide supporting data.

Response:

a. The Company experienced the following total number of streetlight outages in each of the following years:
   - 2017: 21,234
   - 2018: 19,368
   - 2019: 19,727

   These numbers reflect the total number of outages in each year. The Company does not track the number of streetlights affected by outages as requested.
b. For each year, the average outage duration was as follows:
   - 2017: 6 days
   - 2018: 8 days
   - 2019: 8 days
c. The average total annual outage time per fixture was as follows:
   - 2017: 10.33 hours
   - 2018: 11.44 hours
   - 2019: 12.17 hours
d. In each year, the following number of outages exceeded five days:
   - 2017: 7,204
   - 2018: 6,925
   - 2019: 7,748

Supporting data for subpart (d) is provided in Attachment 1 to this discovery response.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 13, 2020

CASE NO. 2020-00349 AND CASE NO. 2020-00350
LEXINGTON-FAYETTE URBAN COUNTY GOVERNMENT
AND LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT

Exhibit Bunch 15

GE Evolve™
LED Roadway Lighting
ERL1-ERLH-ERL2

The **Evolve** LED Roadway Luminaire is optimized for customers requiring a LED solution for local, collector and major roadways. GE's unique reflective optics are designed to optimize application efficiency and minimize glare. The modern design incorporates the heat sink directly into the unit for heat transfer to prolong LED life. This reliable unit has a 100,000 hour design life, significantly reducing maintenance needs and expense over the life of the fixture. This efficient solution lowers energy consumption compared to a traditional HID fixture for additional operating cost savings.

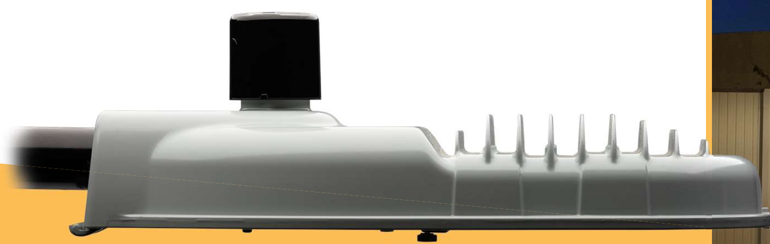
Features:

- Optimized roadway photometric distributions
- **Evolve**™ light engine consisting of reflective technology designed to optimize application efficiency and minimize glare
- 70 CRI at 2700K, 3000K and 4000K typical.
- –40°C to 50°C UL Ambient Typical.
- ULOR = 0 (zero uplight)
- Designed & Assembled in USA

Applications:

- Local Roadways
- Collector Roadways
- Major Roadway/Streets

Compatible with **LightGrid**™ Outdoor Wireless Control System



To learn more about **GE Evolve LED Roadway Lighting**, go to: **www.currentbyge.com**

Exhibit Bunch 16

best describes reliability performance data. It identifies the occurrence of abnormal conditions that grossly affect the reliability of an electric system.

Events that typically result in exclusion from "normal" or unadjusted reliability metrics include major weather events or natural disasters. These major events are excluded because they typically present risks to the electric system which are beyond the design or operational limits of a utility's electric system.

Building on MED concepts, EDO also uses a Gray Sky Day (GSD) measurement to help normalize weather and other events which create an abnormal number of outage activity on the system. GSD thresholds are calculated by multiplying the MED threshold for outage activity by one-third. The GSD metric is used primarily for internal reporting and discussion.

Figure 1 displays calculated MEDs and GSDs for electric distribution reliability between 2010 and 2019.

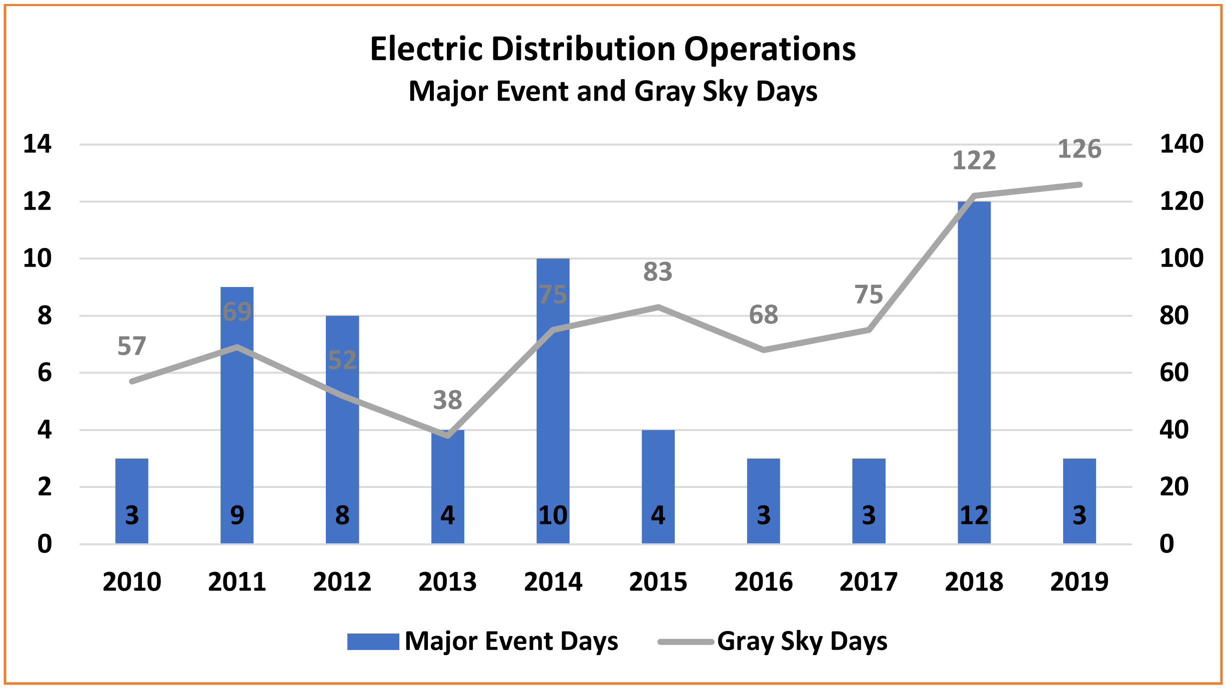


Figure 1. Electric Distribution Operations Major Event Days and Gray Sky Day Trends

Explanations for the steep increase in gray sky days for 2018 and 2019 appear to tie primarily to weather. In 2018, the Companies experienced two Level III and IV events. Data provided by EDO's weather service indicates that the number of days where wind speeds greater than 35 mph were experienced in representative weather stations in the LG&E and KU service areas increased by 12% from the ten-year norm during 2018. Amazingly, the number of days where wind speeds greater than 35 mph were experienced during 2019 increased by 52% from the ten-year norm.

Exhibit Bunch 17

In 2019, DTE Electric experienced 32 weather events: one was a catastrophic storm interrupting greater than 10% of the customer base (MPSC catastrophic criteria). In 2019, DTE Electric was in storm restoration mode for 85.3 days (6.5 days for the MPSC catastrophic storm and 78.8 days for smaller storms) – yet by IEEE definition, there were only six MEDs. Hence, a significant portion of the storm restoration is included in the non-MEDs metrics.

Major Event Days

In 2019, there were a total of six Major Event Days (MEDs). Three occurred during the one MPSC catastrophic storm, occurred during a DTE catastrophic storm (typically interrupting greater than 5% of the customer base), and two occurred during DTE non-catastrophic storms and/or normal conditions.

Storm Criteria	Customers Interrupted	Storm Start Date/Time	Storm Finish Date/Time	Days in Storm Mode	# MEDs	MED Dates
MPSC	411,319	07/19/19 11:00	07/25/19 23:59	6.5	3	July 19, 20, 21

Year	# MEDs During DTE Catastrophic Storms	# MEDs During DTE Non-Catastrophic Storms And Normal Conditions
2010	3	9
2011	7	10
2012	8	2
2013	9	1
2014	9	0
2015	1	2
2016	2	0
2017	6	3
2018	4	5
2019	4	2

CASE NO. 2020-00349 AND CASE NO. 2020-00350
LEXINGTON-FAYETTE URBAN COUNTY GOVERNMENT
AND LOUISVILLE/JEFFERSON COUNTY METRO GOVERNMENT

Exhibit Bunch 18

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

(Continued From Sheet No. D-*94.10*)

General Terms

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

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered *LED* Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered *LED* Lighting equipment that is out of service. If, for some reason, the Company is not able to make such restoration within one full billing month from the date the outage is first reported to the Company, the Company shall provide a credit to the customer's bill for unmetered lighting service. The credit shall be applied to the customer's bill beginning with the second full billing month after the outage is reported.

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of *five* years or more.