BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 20-1651-EL-AIR

CASE NO. 20-1652-EL-AAM

CASE NO. 20-1653-EL-ATA

2020 DISTRIBUTION BASE RATE CASE

BOOK III – TESTIMONY

VOLUME 4 OF 4

Dayton Power and Light Company

DP&L Case No. 20-1651-EL-AIR

Standard Filing Requirements for Rate Increases

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BEFORE THE

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THE DAYTON POWER AND LIGHT COMPANY

CASE NOS. 20-1651-EL-AIR
20-1652-EL-AAM
20-1653-EL-ATA

DIRECT TESTIMONY OF
TYLER A. TEUSCHER

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- ■ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- ■ **RATES AND TARIFFS**
- ■ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

TESTIMONY OF
TYLER A. TEUSCHER

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Tyler A. Teuscher. My business address is 1065 Woodman Drive, Dayton,
4 Ohio 45432.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or the "Company")
7 as a Program Manager in the Regulatory Operations department.

8 **Q. How long have you been in your present position?**

9 A. I assumed my present position in January 2019. Prior to that time, I was an Analyst in
10 the Regulatory Operations department, responsible for the Energy Efficiency Rider,
11 Decoupling Rider, Reconciliation Rider Nonbypassable, Universal Service Fund Rider,
12 and DP&L's Standard Offer Rate recovery mechanism. During my time as an Analyst, I
13 was also responsible for all Energy Efficiency, Competitive Retail Market, and
14 Wholesale Distribution Service policy issues and regulatory filings at both the Public
15 Utilities Commission of Ohio ("PUCO" or the "Commission") and the Federal Energy
16 Regulatory Commission ("FERC").

17 **Q. What are your responsibilities in your current position?**

18 A. I am responsible for assisting in the overall development, analysis, revision,
19 administration, and tracking of rate recovery and compliance with the Company's tariff
20 schedules and policies. I am involved in evaluating regulatory and legislative initiatives,
21 and regulatory commission orders that affect the Company's rates and overall regulatory
22 operations.

Q. Will you describe briefly your educational and business background?

A. Yes. I received a Bachelor of Science degree in Business Economics and a Bachelor of Science degree in Marketing from the University of Kentucky in 2009. I received a Master of Business Administration degree from Miami University in 2017. I have been employed by DP&L since January 2011.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio?

A. Yes. I have sponsored testimony before the PUCO in the Company's Distribution Rate Case, Case No. 15-1830-EL-AIR. In addition, I have sponsored testimony supporting the Commission approved Stipulation and Recommendations in DP&L's Third and Fourth Energy Efficiency and Peak Demand Reduction Program Portfolios, Case Nos. 16-649-EL-POR and 17-1398-EL-POR, respectively.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to support the overall financial summary schedules, a request for deferral authority, distribution of the revenue increase, rate design methodology, and the Company's proposed distribution rates.

III. SCHEDULES AND WORKPAPERS

Q. What schedules and workpapers are you supporting?

A. I am supporting the following schedules and workpapers:

- Schedules A-1
- Schedule E-3.1

- Workpaper E-4, E-4a, E-4b, E-4c, and E-4d

Q. What information is contained in Schedule A-1?

A. Schedule A-1 is an overall financial summary for the test year and date certain. This schedule summarizes data supported by other witnesses. The data presented shows that, at proposed rates, DP&L would earn a 7.71% overall rate of return for the test year and that an increase of $120.8 million over current base distribution revenue is required to earn the requested 7.71% rate of return as specified by Company Witness Illyes. The revenue increase requested on line 17 is shown in detail on Schedule E-4, with an analysis on Schedule E-4.1. Schedules E-4 and E-4.1 are sponsored by Company Witness Adams.

Q. What information is contained in Schedule E-3.1?

A. Schedule E-3.1 is the customer charge analysis and is for informational purposes only. This schedule collects data for certain FERC accounts from the cost of service study on Schedule E-3.2b, sponsored by Company Witness Chapman, which represents customer-related costs. The methodology shown on Schedule E-3.1 is similar to the methodology used in the Staff Report in DP&L's last rate for the residential class only; however, in this case, DP&L has performed a detailed cost of service study to determine customer- and demand-related costs to develop rates for all classes. Utilizing a detailed cost of service study is a critical step in the development of appropriate rates because it properly allocates costs to all cost causers, while establishing a consistent methodology for development of rates for all customer classes. The proposed rates developed for each rate code are shown on Workpaper E-4.

Q. What information is contained in Workpapers E-4, E-4a, E-4b, E-4c, and E-4d?

A. Workpaper E-4 shows the calculation of rates for each rate code with tariff classes. Proposed revenue requirements from Schedules E-3.2a and E-3.2b are divided by billing determinants on Workpapers E-4.1a and E-4.1b. Workpaper E-4a shows the calculation of kVAR charges for the Primary and Primary Substation classes. Workpaper E-4b shows the calculation of customer charges for the rate codes in the Secondary class. Workpaper E-4c shows the calculation for the Secondary and Primary low load factor provision rates. Workpaper E-4d shows the calculation for Private Outdoor Lighting rates.

IV. REQUEST FOR DEFERRAL AUTHORITY

Q. Please explain the Company's request for deferral authority.

A. The request for deferral authority is related to rate case expenses. The Company is requesting deferral authority for rate case expenses requested on Schedule C-8.

Q. Please explain the Company's second request for deferral authority?

A. DP&L is proposing to include, as part of base distribution rates, Customer Programs to educate customers on how to manage their energy and peak demand use, as well as incentivize customers to reduce energy and peak demand through more efficient use of technology. These Customer Programs are more fully described in the direct testimony of Company Witness Campbell. In the event that the Commission believes these programs are not appropriate to be included as part of test year expenses for purposes of developing a revenue requirement for base distribution recovery, the Company is requesting deferral authority for costs associated with these customer programs. To the extent the Commission prefers this alternative proposal, DP&L will defer all costs of

1 these customer programs and file for recovery in a future proceeding. DP&L is not
2 requesting carrying charges be calculated on this deferred balance.
3 The Ohio Revised Code ("O.R.C.") provides that DSM programs should be considered
4 by the Commission in the context of deferral of a regulatory asset. O.R.C.
5 §4928.01(A)(26) defines regulatory asset to include deferred DSM costs and the State
6 Policy reflected in O.R.C. §4928.02(D) is to implement DSM programs. Finally, O.R.C.
7 §4905.70 says that the Commission "shall" initiate DSM programs.

8 **V. <u>DISTRIBUTION OF PROPOSED REVENUE INCREASE</u>**

9 **Q. Did the cost of service study show that the increase required for each customer class**
10 **was proportional?**

11 A. Yes, the cost of service study shows the present rate of return on page 1, line 21 of
12 <u>Schedule E-3.2,</u> which is mostly consistent between customer classes. However, the
13 present rate of return of the High Voltage class was above 7.71%, therefore, that class is
14 showing a proposed decrease in revenue from base distribution rates. Applying the total
15 proposed rate of return of 7.71% to each class results in fair and equitable increases to all
16 customer classes.

17 **Q. Why does this disparity between the High Voltage class and the other classes exist?**

18 A. The disparity exists due to the extremely low cost to serve and small number of
19 customers taking service at the High Voltage level. The class rate design, which is only a
20 customer charge, also factors into the disparity in proposed and actual revenue. Any
21 increases or decreases to the number of customers being served at this voltage level can
22 cause what appears to be dramatic shifts in the present rate of return for that class but is a
23 negligible amount of the total return.

1 **VI. RATE DESIGN**

2 **Q. What was your primary objective of rate design?**

3 A. The primary objective was to recover the appropriate amount of revenue from each class
4 through just and reasonable rates.

5 **Q. What principles did you consider in rate design?**

6 A. There were several long-standing principles considered, including: cost of service,
7 stability, simplicity, non-discrimination, efficiency, and gradualism.

8 **Q. Please explain how each was considered.**

9 A. Cost of Service – The proposed rates were based on a cost of service study that properly
10 applied cost causation principles in allocating costs to customer classes.
11 Stability – Customers will experience more stable and predictable prices under the
12 proposed methodology.
13 Simplicity – The proposed rates are easy to understand and administer. Prices are
14 transparent and easily calculated, so they are more predictable for the customer.
15 Non-discrimination – The proposed rates promote fairness and reduce undue
16 subsidization between customers in the same class as well as between classes.
17 Efficiency – The proposed rates encourage good decision making by consumers and
18 appropriately assigns costs to cost-causers.
19 Gradualism – The proposed rates are for the base distribution portion of the customer's
20 bill, which are generally a small piece of the total bill. Additionally, bills as a result of
21 these rate changes will be lower than bills in 2019.

Q. Do each of these principles receive equal weight in determining just and reasonable rates?

A. No. There is no formula to weight or apply each principle. These principles are not always consistent with each other, but each should be considered in order to make sure that the Company is proposing just and reasonable rates.

Q. Please generally describe the current rates.

A. DP&L's current rates were originally established in Case No. 15-1830-EL-AIR. DP&L's rates were established for tariff classes, which are defined by the nature and voltage level of service.

Q. Please describe the nature of distribution costs.

A. The distribution system is designed and installed to deliver electricity to customers. Electric distribution service costs are predominantly fixed. That is, once facilities are installed and serving customers, the costs are by their nature fixed and do not vary based on the volume of electricity consumed. The equipment installed for each tariff class of customer is similar and therefore it is appropriate that customers within a class be charged similarly. As an example, residential customers have similar meters, transformers, and sized lines, and therefore should be charged similarly and not primarily on a volumetric basis of kWh consumed. Likewise, customers served at secondary voltage require more distribution equipment than customers served at primary voltage, thus the secondary customers have higher distribution costs than primary customers.

Q. Please summarize the proposed rate design.

A. The rates proposed are based on the cost of service study. The cost of service study identified costs as customer-related and demand-related. Customer-related costs are recovered through a customer charge; demand-related costs through demand-based charges. If a customer class does not have demand meters, the demand-related costs were assigned to a kWh charge.

Q. Was a cost-of-service study used to establish a revenue requirement for each class?

A. Yes, Schedule E-3.2, page 1, line 15 shows the revenue requirement by class.

Q. Please explain how you developed the proposed rates.

A. The revenue requirements by tariff class, shown on Schedule E-3.2, page 1, line 15, are divided by billing determinants shown on Workpapers E-4.1a, and E-4.1b. For the residential class, the customer-related costs were used to develop the customer charge. This methodology was also used for the Streetlighting class that also does not use demand meters.

Q. What rate changes are the Company seeking?

A. Amended Substitute House Bill No. 6 ("HB6") required that DP&L develop and implement an energy only (kWh) rate for County Fair service for both its Secondary and Primary classes. The rates were developed by calculating a class average rate for both the Secondary and Primary classes using the existing revenue requirement from Case No. 15-1830-EL-AIR and was implemented February 1, 2020. DP&L is continuing that provision in this case and maintains the same calculation as utilized in Case No. 19-1920-EL-UNC in developing the County Fair rates. The rate of the energy only charge for this service is shown on Workpaper E-4.

1 **Q. Are there other rate changes the Company is seeking?**

2 A. Yes. The Company is proposing to institute a small constant load service provision,
3 which represents a new non-metered Secondary Tariff provision and is supported by
4 Company Witness Bentley. This proposed service is available upon application and is
5 intended for devices with rated load requirements of 25W or less. DP&L did not forecast
6 billing determinants or revenue for this service provision since it is not currently
7 available, is a unique service and will be available only upon application. The calculation
8 of the charge for this new service is shown on Workpaper E-4b.

9 **Q. Are there changes to other tariff classes?**

10 A. Yes. The Company proposes to rename and adjust the Company's current Secondary and
11 Primary maximum rate charge provision to the "Low Load Factor Provision". This
12 renaming provides customers with more clarity regarding the purpose of the provision.
13 In addition, DP&L is proposing that this rate be established to target customers with load
14 factors of 10% or lower. This rate based on a 10% load factor accomplishes the intended
15 purpose of the provision, which is to protect certain customers by limiting the average
16 rate that customers with high peak demand but low monthly usage, are charged. This rate
17 was developed by subtracting the current Transmission Cost Recovery Rider –
18 Nonbypassable ("TCRR-N") and Rate Stabilization Charge ("RSC") maximum charge
19 rates from the sum of the average TCRR-N, RSC, and proposed base distribution rates for
20 usage at a 10% load factor for both the Secondary and Primary classes. The calculations
21 for this rate provision are shown on Workpaper E-4c.

22 **Q. How did you develop the Private Outdoor Lighting distribution rate?**

A. Private Outdoor Lighting rates were developed on Workpaper E-4c. Data from the cost of service study was used to develop a customer charge, fixture charge, additional pole charge, and additional span charge.

Q. Did you make any modifications to the Residential Heating class?

A. No. Today, the Residential Heating class has the same Distribution rates as the Residential class and this case proposes to maintain that same structure. DP&L's Residential Heating discount has been, and I expect will continue to be part of its Residential Heating generation rate in Tariff Sheet G10 and Rate Stabilization Charge in Tariff Sheet G12.

VII. TARIFFS

Q. What tariffs are you supporting?

A. I am supporting the rates and provisions of Tariff Sheet Nos. D17 through D25. Company Witness Adams supports the service terms and miscellaneous service charges.

VIII. CONCLUSION

Q. Please summarize your testimony.

A. The summary schedules that I sponsor represent the revenue increase required to afford the Company an opportunity to earn a fair rate of return on its distribution operations. This includes recovery of regulatory assets that were incurred providing required services to customers. Additionally, the proposed rate design is appropriate and reasonable when evaluated on sound regulatory principles. The proposed rates were developed so that each class pays their fair share of the overall system costs based on the cost of service study. As described and shown on the attachment to Company Witness Adams

testimony, DP&L's proposed total bill for residential customers using 1,000 kWh per month will continue to be the lowest in the state. The proposed rate design presents a fair and reasonable opportunity to recover authorized revenue and, like the Company's request for a distribution revenue increase and recovery of certain regulatory assets, should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NOS. 20-1651-EL-AIR
20-1652-EL-AAM
20-1653-EL-ATA

DIRECT TESTIMONY
OF MARK L. VEST

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF
MARK L. VEST

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Mark L. Vest. My business address is 1900 Dryden Rd., Dayton, Ohio,
4 45439.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by AES US Services, LLC as Director, Maintenance, Inspection &
7 Contract Management, Reliability Programs in the U.S. and Utilities Strategic Business
8 Unit ("U.S. SBU") of The AES Corporation ("AES"), with responsibilities for The
9 Dayton Power & Light Company ("DP&L" or "Company") and other AES businesses.

10 **Q. How long have you been in your present position?**

11 A. I assumed my present position on December 22, 2013. I have spent the last 26 years at
12 DP&L and AES in various capacities ranging from customer service, credit &
13 collections, customer call center and service operations. For the last 16 years, I have
14 been responsible for field operations, vegetation management and infrastructure
15 inspection programs. I have also been responsible for transmission and distribution
16 vegetation management at Indianapolis Power & Light ("IPL") for the past 7 years.

17 **Q. What are your responsibilities in your current position?**

18 A. In my current position, I am responsible for transmission and distribution vegetation
19 management at DP&L and IPL, Ohio Electric Service Safety Standards ("ESSS")
20 regulatory compliance and infrastructure inspection programs at DP&L, storm restoration
21 at both DP&L and IPL and ultimately the safe and reliable delivery of electric service to
22 all of our Ohio and Indiana electric customers.

23 **Q. Will you describe briefly your educational and business background?**

A. I received a bachelor's degree in Accountancy from Wright State University in 1986. Prior to my employment at DP&L/AES I spent several years in public accounting, petroleum wholesale and construction industries.

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to provide an overview of DP&L's distribution vegetation management program and our plans to expand our current program to enhance reliability for our customers.

II. DP&L'S LINE CLEARANCE PROGRAM

Q. Can you describe DP&L's distribution system and provide an overview of its line clearance program?

A. Yes. DP&L's distribution system has approximately 10,500 miles of primary and secondary voltage lines that require varying levels of vegetation management (trees, brush, vines etc.). DP&L employs a systematic cyclical vegetation management program which is viewed by the industry as most effective in minimizing vegetation related interruptions. This type of cyclical program: (i) is the most cost effective; (ii) is a highly successful way of minimizing threats to electrical infrastructure; and (iii) helps to ensure a high level of safety both to the public and to our employees and line maintenance contractors. Various segments of every electrical utility system require variable cycle lengths based upon the vegetation present, past vegetation management, growth rates, and customer impact, just to name a few. The outage frequency reduction benefits of a well-designed cyclical maintenance program can also reduce wear and tear on other components of the distribution system (substation circuit breakers, switches, conductors etc.) and thereby help to minimize repair and replacement costs.

Q. Can you describe DP&L's distribution vegetation management practices?

A. Yes. The current DP&L vegetation management practices primarily address trees in the right of way ("ROW") through trimming and targeted removals. Trees out of the ROW, which also impact distribution reliability, are more difficult to manage because DP&L has limited rights and ability to access them. While DP&L's vegetation management practices have been reasonable, we have experienced a 128% increase in customer interruptions ("CI") from 8,534 CIs on an annual basis for the period 2014-2016 to 18,727 CIs annually for the period 2017-2019 due to trees in the ROW. Instances of outages related to trees out of the ROW are also responsible for an increasing number of outages and longer restoration times. Trees out of the ROW CI have increased 39% from 33,185 CIs on an annual basis for the period 2014-2016 to 53,491 CIs annually for the period 2017-2019.

Q. Can you explain why CIs associated with trees inside of the ROW have been increasing?

A. Yes. In recent years CIs associated with trees inside of the ROW have been increasing due to our selective deferral of cycle trimming because dramatic increases in costs have made it impossible for us to complete our in the ROW trimming on the 5-year cycle. DP&L, like many other utilities, has been forced to defer that work due to significant increases in costs. Specifically, developments in the utility vegetation management industry over the past several years (labor shortages and employee turnover, rapid cost increases due to the escalation of labor costs etc.) have made it more difficult for DP&L, and other electric utilities, to adhere to annual work plans, cycle trimming schedules, and mitigate trees outside of the ROW. This deferral of work allows additional growth of the vegetation present and leads to additional system impacts.

Q. Can you describe why CIs associated with trees out of ROW have been increasing?

1 A. Yes. As I described above, due to the rapid increase in costs, our current program lacks
2 sufficient funds to complete our in the ROW trimming needs, and therefore, there is no
3 budget for addressing trees outside of the ROW at all. Therefore, DP&L's current
4 program does not address trees outside of the ROW until they have caused an outage or
5 other damage to the system, frequently as the result of a storm.

6 In addition, the Emerald Ash Borer has been causing an increasing frequency of whole
7 trees and large tree limbs to fall onto and to damage DP&L's distribution equipment,
8 causing CI's. DP&L is experiencing more catastrophic and damaging vegetation impacts,
9 which have contributed to negative reliability metrics. Operational challenges related to
10 vegetation out of the ROW plagues not only DP&L, but most, if not all, electric utilities
11 in the Midwest.

12 **Q. What is shown on Attachment MLV-1?**

13 A. Attachment MLV-1 "*Tree Related Outage History (2014-2019)*" shows outage events
14 for the years 2014-2019 broken down between Trees in ROW and Trees out of ROW.
15 The outage data includes number of events, CI and customer minutes interrupted (CMI).

16 **Q. What is the source of the information shown on Attachment MLV-1?**

17 A. The information on that attachment is based on historical data housed in DP&L's outage
18 management system and was also used to prepare DP&L's annual ESSS Rule 10 filings
19 per OAC 4901:1-10-10.

20 **Q. What is shown on Attachment MLV-2?**

21 A. Attachment MLV-2 *Historical Production and Cost Per Mile* shows actual distribution
22 vegetation management expenditures for the years 2013-2019, actual miles trimmed,
23 actual number of circuits trimmed, and the associated actual cost per mile.

1 **Q. What is the source of the information shown on Attachment MLV-2?**

2 A. The information on that schedule was developed from DP&L's financial management
3 system.

4 **III. <u>DP&L'S PROPOSED LINE CLEARANCE PROGRAM</u>**

5 **Q. Does DP&L have a strategy to address the issues you described?**

6 A. Yes. Improving reliability and safety in response to vegetation conditions across the
7 DP&L system will require an expansion of DP&L's current program and a migration to a
8 more cost and operationally effective, proactive maintenance program, as opposed to the
9 reactive situation we currently find ourselves in. Therefore, DP&L has developed a long-
10 term strategy that identifies vegetation conditions, optimizes the availability of qualified
11 vegetation management crews, and includes a well-designed cycle trimming program, a
12 focused tree and brush removal program, an effective hot-spotting or intra-cycle
13 maintenance program and a program to address vegetation outside of the ROW. In order
14 to effectively manage trees in the ROW or trees out of the ROW, DP&L will need to
15 execute a hybrid cyclical trim cycle (4/5 years) to minimize interruptions. Specifically,
16 we would first enlist the services of additional Utility Foresters to patrol our system to
17 perform tree risk assessments on "Danger Trees" (trees with a high likelihood of
18 contacting electric supply lines) that are identified by them or other vegetation
19 management or DP&L operational personnel. Secondly, we would prioritize the
20 identified trees for mitigation based upon their probability of failure and the estimated
21 impacts to reliability, safety, and cost. After this identification and prioritization, we
22 would need to secure additional qualified tree trimming crews to perform the necessary
23 removals. This is and will most likely continue to be a very difficult and costly

proposition as qualified resources in the industry are often a challenge to find and expensive to hire.

Q. What steps has DP&L taken to develop and begin implementation of this new strategy?

A. DP&L recently engaged ACRT, Inc. and Arborcision to perform a system vegetation assessment so that DP&L could better understand the vegetation conditions prevalent on its system. Through this analysis, a "Criticality Ranking" methodology (0 – most critical to 5 least critical) was created, which weighs the various factors that drive cost in vegetation management (vegetation density, reliability data, type of trimming required, tree species, growth rates, crew availability and capabilities etc.). This Criticality Ranking carries a strong correlation to reliability. The Criticality Ranking system is used to assign circuits to a trim cycle (4 or 5 years) that best controls cost and the reliability threat/risk associated with each circuit. With this in mind, urban circuits with predominantly off-road construction and higher levels of vegetation density are assigned Criticality Rankings in the 0-2 range and will require more frequent trimming maintenance (4 years), whereas circuits with a more rural profile, higher presence of easily accessible on-road construction and more sparse vegetation density will have Criticality Rankings in the 3-5 range and therefore require less frequent cyclical maintenance (5 years).

Q. Is DP&L's proposed expanded program needed to promote safety and reliability?

A. Yes. Safety is always DP&L's top priority, and outages caused by vegetation can lead to electrocution risks for DP&L's customers as well as the risks and hazards to our employees and contractors who perform maintenance on our infrastructure and restore

electrical service to our customers after severe weather events and other types of outages. Vegetation is typically the leading cause of outages.

Q. Will DP&L's proposed expanded program improve CI for trees inside of the ROW and outside the ROW?

A. Yes. Migration to a more appropriate cycle duration (4-5 years) will enable us to more proactively address vegetation issues inside of the ROW without deferral of work and thereby reduce interruptions. With regards to trees outside of the ROW, we can address them with the permission of the property owner. Our proposed proactive Danger / Hazard Tree plan will avail us the resources to actively identify and mitigate trees outside the ROW that we currently do not have the funding to address, thereby reducing CIs due to trees outside the ROW.

Q. How did DP&L determine what the expanded program will cost?

A. DP&L solicited bids for competitive rates and employed several contractors in order to maintain a competitive environment for work completion and cost containment. DP&L utilizes medium sized regional contractors and large national contractors to ensure that it has access to labor and equipment resources and continuously monitors market conditions for opportunities and risks.

Q. Can you identify and describe DP&L's projected costs for this expanded program?

A. Yes. The costs are as follows:

Expanded Program Projected Costs

Year 1

- Circuit maintenance (Trees in ROW) - $25,000,000
- Intra-cycle hot-spotting (reliability trimming) - $1,500,000
- Danger / Hazard Trees (Trees out of ROW) - $3,500,000

Year 2

- Circuit maintenance (Trees in ROW) - $25,000,000

- Intra-cycle hot-spotting (reliability trimming) - $1,500,000
- Danger / Hazard Trees (Trees out of ROW) - $3,500,000

Year 3

- Circuit maintenance (Trees in ROW) - $25,000,000
- Intra-cycle hot-spotting (reliability trimming) - $1,500,000
- Danger / Hazard Trees (Trees out of ROW) - $3,500,000

The above cost estimates are based upon current cost performance and do not reflect future market conditions that are not foreseeable at this time (labor shortages, lack of available qualified crews or per diem costs associated with off system crew mobilization etc.). Therefore, cost and execution risks do exist and will be addressed through competitive bidding and innovative procurement strategies, temporary utilization of traveling "off cycle" crew resources, and the use of technology and specialized equipment to the fullest extent possible.

Q. How does DP&L plan to recover the costs associated with the vegetation management program that you described?

A. As explained by DP&L Witness Forestal, the Company has included the annual Year 1 through Year 3 Projected Program Costs of $30.0 million (see table above) in the pro forma adjustment detailed on Schedule C-3.9.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

1467558.1

Attachment MLV-1

Tree Related Outage History (2014-2019)

	Trees in ROW				Trees out of ROW		
Year	**Events**	**CI**	**CMI**		**Events**	**CI**	**CMI**
2014	175	12,483	1,678,403		620	23,670	3,683,114
2015	145	7,007	1,393,088		667	46,267	5,402,862
2016	116	6,112	2,006,194		649	29,618	4,372,141
2017	318	17,128	3,265,144		772	51,862	6,474,520
2018	310	16,973	3,366,969		936	52,055	8,137,607
2019	368	22,079	4,318,048		990	56,557	10,961,195
2014-2016 AVG	145	8,534	1,692,562	2014-2016 AVG	645	33,185	4,486,039
2017-2019 AVG	332	18,727	3,650,054	2017-2019 AVG	899	53,491	8,524,441
VARIANCE	187	10,193	1,957,492	VARIANCE	254	20,306	4,038,402
%	128%	119%	116%		39%	61%	90%

The source of this data is the DPL Annual Rule 10 filing and excludes MED's and transmission outages.

Attachment MLV-2

DPL Distribution Line Clearance

Historical Production and Cost Per Mile

Year	Actual Expenditures	Actual Miles Trimmed	Actual Circuits Trimmed	Actual Cost Per Mile
2019	$ 20,421,298	1462	91	$ 13,968
2018	$ 15,800,508	1319.25	71	$ 11,977
2017	$ 9,969,307	1094.5	45	$ 9,109
2016	$ 10,208,682	2149	78	$ 4,750
2015	$ 11,402,510	2215	99	$ 5,148
2014	$ 12,563,041	2232.25	111	$ 5,628
2013	$ 10,988,355	1570.25	73	$ 6,998

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NOS. 20-1651-EL-AIR
20-1652-EL-AAM
20-1653-EL-ATA

DIRECT TESTIMONY OF
C. KENNETH VOGL

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF
C. KENNETH VOGL

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1 **I. POSITION, QUALIFICATIONS AND PURPOSE OF TESTIMONY**

2 **Q. Please state your name and business address.**

3 A. My name is C. Kenneth Vogl. My business address is 101 South Hanley, Suite
4 900, St. Louis, Missouri, 63105.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am employed by Willis Towers Watson as a senior retirement consultant and
7 actuary.

8 **Q. Please summarize your educational background.**

9 A. I received a Bachelor of Science degree in Mathematics from the University of
10 Missouri, Columbia and Ph. D in Mathematics from Washington University in St.
11 Louis, Missouri. I am a Fellow of the Society of Actuaries and an Enrolled
12 Actuary under the Employee Retirement Income Security Act of 1974 ("ERISA").

13 **Q. On whose behalf are you testifying in this proceeding?**

14 A. I have been retained to provide expert testimony on behalf of Dayton Power &
15 Light Company ("DP&L" or the "Company") about pensions.

16 **Q. Have you previously filed testimony before a regulatory agency?**

17 A. Yes, I have provided written and/or oral testimony to state regulatory agencies in
18 Illinois, Kansas, Minnesota, Missouri, Oregon and New Mexico. Attached
19 Exhibit CKV-1 contains a list of cases in which I have testified.

20 **Q. What is the purpose of your direct testimony in this proceeding?**

1 A. The purpose of my direct testimony is to support the Company's request to
2 include the Retirement Income Pension Plan's Prepaid Pension Asset in rate base
3 and thus earn a return on it. I will describe how Prepaid Pension Assets are
4 created and explain why it is reasonable and equitable for the Company to earn a
5 return on its Prepaid Pension Asset.

6 **Q. Please summarize your conclusions.**

7 A. As of June 30, 2020 DP&L's Retirement Income Pension Plan has a Prepaid
8 Pension Asset of $79.1 million. That Prepaid Pension Asset reflects the fact that
9 DP&L's shareholders have cumulatively contributed more cash to DP&L's
10 Retirement Income Pension Plan than DP&L has recorded and recovered for
11 pension costs. DP&L's pension contributions are made into an irrevocable trust,
12 so DP&L cannot withdraw those excess contributions or use them for other
13 purposes. Recovery of the Prepaid Pension Asset will occur in the future as the
14 Prepaid Pension Asset is recognized in Pension Expense.

15 That Prepaid Pension Asset is used and useful since: (a) it reduces DP&L's
16 pension expense in the test year; and (b) is required by law to be held for the
17 benefit of DP&L employees. Thus, just like any other used and useful asset,
18 DP&L should be able to earn a return on its Prepaid Pension Asset.

19 **Q. Has the Commission previously recognized that a utility should be permitted**
20 **to include a prepaid pension asset in rate base?**

21 A. Yes, the Commission has previously held that a prepaid pension asset should be
22 included in rate base. In re Ohio Power Company, Case No. 10-2929-EL-UNC,

1 Opinion and Order, p. 34 (July 2, 2012) ("With regard to AEP-Ohio's prepaid
2 pension asset, however, we agree with the Company that Mr. Smith's exclusion of
3 this item was inconsistent with Staff's recommendation in the Company's recent
4 distribution rate case . . . , as well as our treatment of pension expense in other
5 proceedings. We see no reason to vary our practice in the present case and,
6 therefore, find that AEP-Ohio's prepaid pension asset should not have been
7 excluded.") (Footnote omitted.). Accord: In re Ohio Edison Co., Case No. 07-
8 551-EL-AIR, et al., Opinion & Order, p. 16 (Jan. 21, 2009).

9 **Q. Has the Commission's Staff recognized that a prepaid pension asset should**
10 **be included in rate base?**
11 A. Yes, the Commission's Staff has also done so. In re the Application of Columbus
12 Southern Power Co., Case No. 11-351-EL-AIR, et al., Staff Report of
13 Investigation, p. 7 (September 15, 2011) ("The Staff increased rate base to
14 recognize a prepaid pension asset. . . . The additional contributions represent
15 cash investment above the amount of the pension cost included in the cost of
16 service or the income statement. The additional contributions benefit customers
17 by reducing future pension costs through increased earnings.")

18 **II. PREPAID PENSION ASSET**
19 **A. Pension Accounting and Funding Requirements**
20 **Q. What standards apply to the accounting for pension benefit obligations and**
21 **expense?**
22 A. The accounting rules for pension plans in the United States are established by the
23 Financial Accounting Standards Board.

1 Current standards are published under Accounting Standards Codification 715
2 ("ASC 715"), effective for reporting years ending after December 15, 2017. ASC
3 715-30 applies to accounting for pensions. Prior to recodification under ASC
4 715, which did not change the methodology published in prior standards,
5 standards for pension expense calculations were published as Statement of
6 Financial Accounting Standard No. 87 ("FAS 87") effective for reporting years
7 ending after December 15, 1986.

8 Prior to the effective dates of FAS 87, pension obligations and expense were
9 accounted for on a "pay as you go" basis, whereby annual expense was equal to
10 cash contributions made to the plan.

11 **Q. What are the general principles governing current pension plan accounting**
12 **calculations?**

13 A. Current pension accounting rules were designed primarily to:

14 1) attribute plan costs to the period in which employees earn benefits, regardless
15 of when an organization actually funds those benefits with cash contributions, and
16 2) avoid extreme single-period expense volatility associated with changes in
17 unfunded plan obligations resulting from actual demographic or investment
18 experience, as well as changes in assumptions or plan provisions.

19 It is important to note that differences in cost calculation methodologies do not
20 affect the actual cost of providing the benefits, but rather, the *timing* of when
21 those costs are recognized in an organization's financial statements. As such,
22 while the annual attribution of pension expense under ASC 715 is different than

1 under a "pay as you go" approach, the sum of annual expenses and the sum of
2 cash contributions over the lifetime of the plan are the same.

3 **Q. What are the key building blocks for accounting calculations?**

4 A. The three key building blocks are: (1) the measure of the plan's obligation, (2) the
5 measure of the plan's assets, and (3) the measure of the additional benefits being
6 earned by plan participants over the measurement period. The difference between
7 a plan's obligation and assets is known as the "Unfunded Liability". Note that if
8 plan assets exceed the obligation, the Unfunded Liability would be negative (*i.e.*,
9 a surplus).

10 PLAN OBLIGATION: Projected Benefit Obligation ("PBO") is the actuarial
11 present value of employer-provided plan benefits payable based on participants'
12 service through the measurement date. This amount is calculated using plan
13 provisions, census information, and actuarial assumptions at the time of
14 measurement. Actuarial assumptions include, among other things, the discount
15 rate used to reflect time value of money, expected future retirement/termination,
16 expected future salary increases through termination or retirement, expected form
17 of benefit payment (*e.g.*, annuity or lump sum), and expected future mortality.

18 PLAN ASSETS: Fair Value of Assets ("FVA") is equal to the actual value as of
19 the measurement date of assets set aside by the employer in an irrevocable trust
20 for the sole purpose of paying plan benefits.

21 ADDITIONAL BENEFITS EARNED: Referred to as "Service Cost," this is the
22 actuarial present value of employer-provided plan benefits attributed to service in

1 the current measurement period, typically the current fiscal year. It is measured
2 using the same methods (plan provisions, census information, assumptions) used
3 to determine the Plan Obligation (PBO).

4 **Q. What amount is represented and reflected on a company's balance sheet?**
5 A. For fiscal years ending after December 15, 2006, a company is required to
6 recognize on its balance sheet an amount equal to the plan's Unfunded Liability,
7 which represents the difference between the Plan Obligation (PBO) and the Plan
8 Assets (FVA). If the Plan Obligation exceeds the Plan Assets, the company
9 records a liability. If Plan Assets exceed the Plan Obligation, the company
10 records an asset.

11 **Q. What amount is represented and recognized on a company's income**
12 **statement?**
13 A. The company records against earnings the pension expense or more specifically,
14 the Net Periodic Benefit Cost ("NPBC").

15 **Q. How is the NPBC calculated?**
16 A. The basic NPBC is comprised of six separate components:
17 SERVICE COST: described previously, it represents the value of benefits earned
18 by participants over the measurement period.

19 INTEREST COST: it represents interest on the Plan Obligation to account for the
20 passage of time.

1 EXPECTED RETURN ON PLAN ASSETS: a negative item (reducing the
2 NPBC), it represents the amount plan assets are expected to earn, net of
3 investment expenses, during the period.

4 AMORTIZATION OF PRIOR SERVICE COST: Any change in Plan Obligation
5 resulting from plan changes that impact benefits earned in prior periods can be
6 amortized rather than recognized immediately. The amortization period is
7 generally the expected remaining working period of employees who are affected
8 by the plan change.

9 AMORTIZATION OF NET (GAIN) LOSS: Changes in the plan's funded status
10 resulting from actual experience differing from assumptions (for example, plan
11 assets earning more or less than expected), including the impact of changes in
12 assumptions such as the discount rate, can also be amortized over future periods.
13 The amortization period is generally the expected remaining working period of
14 employees participating in the plan (different amortization periods may apply to
15 plans that no longer benefit current employees). The amount subject to
16 amortization is the amount of outstanding gains or losses in excess of a "corridor"
17 defined in ASC 715-30.

18 AMORTIZATION OF INITIAL NET OBLIGATION (ASSET): The difference
19 between the plan's Unfunded Liability and the amount recognized on the
20 company's balance sheet at the time FAS 87 came into effect is defined as the Net
21 Transition Obligation (or Net Transition Asset if the Unfunded Liability is less
22 than the liability recognized on the company's balance sheet). That amount was

1 amortized on a straight-line basis. There is no Transition Obligation left for the
2 Retirement Income Pension Plan ("RIP") sponsored by DP&L.

3 To illustrate the terms, the following Table 1 shows, for DP&L's Retirement
4 Income Pension Plan, the various amounts for the expected 2020 NPBC.
5 Expected employer contributions are also shown.

Components of 2020 NPBC and Expected Contributions
($ in millions)

Service cost	$	3.7
Interest cost	$	11.7
Expected return on plan assets	$	(18.6)
Amortization of initial net obligation (asset)	$	-
Amortization of prior service cost	$	1.3
Amortization of net (gain) loss	$	8.5
Net periodic benefit cost	$	6.6
Employer Contributions	$	7.5

6 **Q. You mentioned "basic" NPBC. Are there circumstances where additional**
7 **costs would be recognized?**
8 A. Yes. Generally Accepted Accounting Principles ("GAAP") defines certain
9 circumstances where recognition of some of the unrecognized costs must be
10 accelerated. Those "Special Events" include settlements, curtailments, and
11 special termination benefits. In those instances, costs that would otherwise be
12 deferred to future periods are recognized immediately. The impact is a one-time
13 additional cost (credit), resulting in a reduction (increase) in future NPBCs.

14 **Q. How does the balance sheet amount relate to the NPBC and employer**
15 **contributions?**

A. First, it is helpful to define two terms:

ACCRUED PENSION LIABILITY (PREPAID PENSION ASSET): The cumulative difference between NPBC (including any special accounting amounts) and company pension contributions. While no longer an amount explicitly reported in accounting disclosures, this concept remains crucial in understanding how costs are reconciled from year to year. For example, during 2020, from table 1 above the Prepaid Pension Asset will increase $0.9 million because the Company made $7.5 million in cash contributions to the trust which is $0.9 million more than the $6.6 million in Pension Expense recorded.

ACCUMULATED OTHER COMPREHENSIVE INCOME ("AOCI"): The accumulated change in plan assets or liability attributable to plan changes or actual experience different than that assumed for the calculation of annual pension expense, *which have not yet been recognized in NPBC*. Said another way, AOCI reflects changes in the Unfunded Liability that have not yet been recognized in prior periods' NPBCs. It is the sum of the unrecognized gains (or losses) and unrecognized prior service costs (or credits). AOCI is included as a component of common stock equity on a company's balance sheet.

At any point in time, the amount recognized on the balance sheet, which is the Unfunded Liability, equals the sum of the Accrued Pension Liability (Prepaid Pension Asset) and AOCI balance. In other words, the Unfunded Liability equals all costs (NPBC) recognized in prior periods less the sum of all employer contributions made, plus costs deferred to future periods.

To illustrate the concept, the following Table 2 shows, for DP&L's Retirement Income Pension Plan, the various amounts at June 30, 2020.

Table 2 – DP&L's Unfunded Liability, Accrued Pension Liability and AOCI

($ in Millions)	RIP Balance Sheet		
Date	Unfunded Liability (1)	Accrued Pension Liability (2)	AOCI (1) - (2)
June 30, 2020	$58.4	($79.1)	$137.5

Table 2 indicates that the RIP is $58.4 million underfunded at June 30, 2020, the employer contributions have exceeded NPBCs by $79.1 million to date, and that there are $137.5 million of deferred costs attributable to past service that will be recognized in future NPBCs.

Q. Is it possible for the same pension cost to be charged twice through the NPBC?

A. No. The mechanics of the NPBC calculations are such that by definition, once a cost has been recognized, it will not be recognized again, whether it was funded or not. The service cost, interest cost, and expected return on asset components measure the cost for the measurement period. While amortizations of prior service cost (credit) and gains (losses) do reflect events that took place in the past, only the portion that has not yet been recognized in prior periods NPBC is subject to amortization.

Q. Are the annual cash funding amounts for pension plans determined under the same standards as the annual NPBC?

1 A. No. ASC 715 does not dictate how a company must fund a pension plan. The
2 funding of a qualified pension plan is determined based upon prudent business
3 practices subject to the rules in the Internal Revenue Code and the Employee
4 Retirement Income Security Act of 1974, as amended by the Pension Protection
5 Act of 2006:

6 • Minimum Contributions are required;
7 • Maximum amounts, for tax purposes, are defined;
8 • The Company has a fiduciary responsibility to prudently protect the
9 interests of the plan participants and their beneficiaries

10 The minimum required contribution and maximum deductible amounts are
11 defined quite differently than the accounting NPBC. Over the life of the pension
12 plan, the cumulative contributions made to the plan and the cumulative pension
13 costs will be equal, but at any point in time during the operation of the pension
14 plan, there is likely to be a significant difference between the two.

15 **Q. Can you explain how DP&L's pension plan can be underfunded while DP&L**
16 **at the same time has a prepaid pension asset?**
17 A. Yes. Those items are separate concepts.

18 Funded Status of a Pension Plan – this concept focuses on the comparison of
19 Pension Plan Assets to Pension Plan Obligations. DP&L's Retirement Income
20 Pension Plan, like most qualified pension plans across the country, are
21 underfunded because the Pension Plan's Obligation exceeds the amount of Assets
22 in the trust. There are many factors that impact the Funded Status, but the two

1 main drivers today are 1) decreasing interest rates which increase obligations, and
2 2) investment returns less than expected.

3 Prepaid Pension Asset – this concept is independent of the Funded Status of a
4 Pension Plan and simply tracks the extent, at a given point in time, to which
5 company cash contributions to the trust have exceeded its accounting pension
6 expense for the plan. Said differently, because total company pension
7 contributions and total accounting pension expense will be equal over the life of a
8 pension plan, the Prepaid Pension Asset is the amount by which accounting
9 pension expense will exceed company cash contributions in the future.

10 **Q. Once the company contributes to the pension plan, can the company use**
11 **those assets for other purposes besides the pension plan?**
12 A. No. A tax-qualified pension plan must satisfy, among other things, the exclusive
13 benefit rule of IRC 401(a)(2) and Treasury Regulation Section 1.401-2. Until all
14 plan liabilities are satisfied with respect to employees and beneficiaries covered by
15 the plan, the exclusive benefit rule prohibits any part of a plan's trust funds to be
16 used for, or diverted to, purposes other than for the exclusive benefit of covered
17 employees and beneficiaries.

18 **<u>B. Prepaid Pension Asset and Rate Treatment</u>**
19 **Q. What topic do you address in this section?**
20 A. In this section, I address how the various pension accounting amounts and
21 concepts under GAAP described in the prior section are used for purposes of

setting rates in Ohio for DP&L. I describe the importance of the Prepaid Pension Asset to ratemaking.

Q. How is the cost of DP&L's Retirement Income Pension Plan reflected in rates?

A. Similar to most utilities in the United States, DP&L uses the level of the NPBC for the Retirement Income Pension Plan during a test period, a portion of which is capitalized and the remaining portion as the cost of service for the prospective rate period.

Q. Is it true that during a rate period, the amount reflected in rates for the cost of a pension plan is equal to the actual NPBC during that same period?

A. No. The annual test period cost is the best estimate at that time of the future cost of the pension plan. Once determined, the test period amount is reflected in rates for each year of the rate period for the pension plan. For example, in DP&L's 1991 rate case, the test period cost would have been $0 since the level of pension expense was negative each year from 1986 through 1994. Therefore, during the rate period from 1991 to 2018, DP&L would not have recovered any of its actual pension costs in rates. Table 3 below shows a history of Pension Expense and Cash Contributions for DP&L's Retirement Income Pension Plan since adoption of FAS 87 provided by the Company collected from actuarial valuation reports and annual reports. I believe the values prior to 1994 contain the Pension Expense for the non-qualified Pension Plan (SERP).

	Table 3	
Year	**Cash Contributions**	**Annual Pension Expense**
1986	$ -	**$ (6.4)**
1987	$ -	$ (6.1)
1988	$ -	$ (1.3)
1989	$ -	$ (1.7)
1990	$ -	$ (2.2)
1991	$ -	$ (1.7)
1992	$ -	$ (1.0)
1993	$ -	$ (1.5)
1994	$ -	$ 0.8
1995	$ -	$ 1.8
1996	$ -	$ 1.0
1997	$ -	$ (1.2)
1998	$ -	$ (3.5)
1999	$ -	$ (6.8)
2000	$ -	$ (13.5)
2001	$ -	$ (7.7)
2002	$ -	$ (9.5)
2003	$ -	$ (3.2)
2004	$ -	$ 1.8
2005	$ -	$ 3.8
2006	$ -	$ 5.2
2007	$ 27.4	$ 2.9
2008	$ -	$ 0.5
2009	$ -	$ 6.6
2010	$ 40.0	$ 10.6
2011	$ 40.0	$ 7.8
2012	$ -	$ 12.1
2013	$ -	$ 11.0
2014	$ -	$ 9.4
2015	$ 5.0	$ 14.6
2016	$ 5.0	$ 13.3
2017	$ 5.0	$ 12.6
2018	$ 7.5	$ 9.2
2019	$ 7.5	$ 7.1
2020 (through 6/30)	$ 7.5	$ 3.3
Total	$ 144.9	$ 68.1

Q. In addition to amounts capitalized and included in cost of service for NPBC, should other pension related amounts also receive rate treatment?

A. Yes. If a regulated utility receives rate reimbursement on a NPBC basis, then it is appropriate to include in rate base any amount that the regulated utility has contributed to the plan in excess of the amount received from customers for the pension plan. Conversely, if the utility funded less than it received from customers, the difference should be deducted from rate base. In the first case, it is appropriate to include the excess in rate base because the company contributions are:

- An acceleration of NPBCs that will occur and become reflected in rates in the future,
- Shareholder provided,
- Made to an irrevocable trust that can only be used for pension plan participants and beneficiaries, and
- Providing additional benefits to customers as described further in my testimony

Q. Is the amount to be added to (or deducted from) rate base simply the prepaid pension asset (or accrued pension liability) for GAAP purposes you described above?

A. Yes. The Accrued Pension Liability (or Prepaid Pension Asset) for GAAP purposes is the cumulative difference between the NPBC and the actual employer contributions made to the pension plan.

Q. Is that consistent with the approach used under other jurisdictions, such as FERC?

A. Yes. In Opinion No. 570 issued in January 2020 in Docket No. ER15-1436-001, FERC addressed the issue of inclusion in rate base of a prepaid amount related to pensions. In paragraph 14, the Opinion states:

> "Based on the above, we find that, as a general matter, it is just and reasonable for a utility to include prepaid pension costs in rate base when its pension expense recovered from ratepayers is less than its contributions to fund pension costs. Likewise, it is just and reasonable for a utility to include accrued pension costs in rate base when it has recovered pension expense from ratepayers in excess of its pension costs."[1]

This FERC opinion is consistent with the DP&L's request to include the Prepaid Pension Asset related to the Retirement Income Plan in rate base.

Q. Does a prepaid pension asset, created by company contributions in excess of its NPBC, provide ongoing benefits to customers?

A. Yes. I will describe the two key benefits customers receive whenever a Prepaid Pension Asset exists:

1. Reduces Future Pension Costs: It reduces the NPBC in future years, and more specifically, in a future test period that would lower the cost of service in future rate proceedings. For example, the RIP has a Prepaid Pension Asset at June 30, 2020 of $79.1 million as shown in Table 2. If the contributions creating the Prepaid Pension Asset were never made, then the current estimate of 2020 NPBC shown in Table 1 would increase from $6.6 million to $11.0 million, or an increase of $4.4 million (assuming an expected return on assets of 5.6%).

[1] [Entery Gulf States La., L.L.C., 170 FERC ¶ 61,019 (2020) (Opinion No. 570, Order on Initial Decision).]

This would happen since the trust assets (assuming no return on these contributions) would be $79.1 million lower, resulting in a ($14.2) million expected return on assets instead of the ($18.6) million expected return on assets shown in Table 1.

2. Lower Long-Term Costs: All pension plans subject to ERISA and the Internal Revenue Code must purchase insurance through the Pension Benefit Guarantee Corporation. One portion of the annual premium, the Variable Rate Premium, is based on the Unfunded Liability of the plan as of the beginning of the plan year. Today, the Variable Rate Premium is roughly 4.5% of the Unfunded Liability, subject to a maximum amount based on total number of participants in the plan. Once again, if the contributions creating the Prepaid Pension Asset were never made, the *annual* Variable Rate Premium would be approximately $3.4 million greater, subject to the maximum. The reduction in long-term costs generated by the Company cash contributions creating the Prepaid Pension Asset is a significant benefit to customers.

C. DP&L's Prepaid Pension Asset Should be Included in Rate Base

Q. Can you explain why DP&L'S prepaid pension asset should be included in rate base?

A. Yes. As shown in Table 2, the Prepaid Pension Asset for the Retirement Income Pension Plan as of June 30, 2020 is $79.1 million. Since the adoption of ASC 715, it is made up of:

- $144.9 million in cumulative Company contributions to the irrevocable pension trust, and

1 • $65.8 million in cumulative NPBCs

2 Once again, looking at Table 2, the Retirement Income Pension Plan is currently
3 underfunded by $58.4 million and has $137.5 million in AOCI (deferred costs)
4 that are expected to be included in future NPBCs, and therefore future rate
5 reimbursement. Said in another way, of the $137.5 million of deferred pension
6 costs to be reimbursed in the future, $79.1 has already been contributed to the
7 pension trust by the Company and $58.4 will be contributed in the future to fully
8 fund the plan.

9 **D. <u>Alternative Recommendation if Rate Base Treatment Is Not Allowed</u>**

10 **Q. Do you have a recommendation if the prepaid pension asset is not allowed to**
11 **be included in rate base?**

12 A. Yes. If the company is not allowed to include its Prepaid Pension Asset in rate
13 base, then the Company should be allowed to make an adjustment to its test
14 period NPBC, a portion of which is capitalized and the remainder included in its
15 cost of service. This adjustment would reverse the benefit the Prepaid Pension
16 Asset provides to customers.

17 **Q. How would that adjustment be made?**

18 A. As seen in Table 1, the adjustment would be made to the amount of the expected
19 return on asset component of NPBC. Specifically, a decrease to the expected
20 return on assets (an increase to the NPBC) would be equal to the expected return
21 on assets assumption, 5.6% for the RIP, multiplied by Prepaid Pension Asset, or
22 $79.1 million. In this case, the amount would be $4.4 million.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Jurisdiction	Company	Docket Number
Missouri Public Service Commission	Empire District Electric Company	ER-2004-0570
Missouri Public Service Commission	Ameren Corporation (AmerenUE)	ER-2007-0002
Missouri Public Service Commission	Ameren Corporation (AmerenUE)	GR-2007-0003
Missouri Public Service Commission	Empire District Electric Company	ER-2008-0093
Missouri Public Service Commission	Great Plains Energy (Kansas City Power & Light)	ER-2010-0355
Missouri Public Service Commission	Great Plains Energy (KCP&L Greater Missouri Operations Company)	ER-2010-0356
Kansas Corporation Commission	Empire District Electric Company	05-EPDE-980-RTS
Kansas Corporation Commission	Great Plains Energy (Kansas City Power & Light)	10-KCPE-415-RTS
Kansas Corporation Commission	Great Plains Energy (Kansas City Power & Light)	12-KCPE-764-RTS
Illinois Commerce Commission	Ameren Corporation (AmerenCIPS, AmerenCILCO, AmerenIP)	06-0070, 06-0071, 06-0072 (consolidated)
Minnesota Public Utility Commission	Xcel Energy (Northern States Power Company)	E002/GR-10-971
New Mexico Public Regulation Commission	PNM Resources (Public Service Company of New Mexico)	10-00086-UT
Public Utility Commission of Oregon	Joint Utilities	UM 1633

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NOS. 20-1651-EL-AIR
20-1652-EL-AAM
20-1653-EL-ATA

DIRECT TESTIMONY OF LAUREN R. WHITEHEAD

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- ■ **OPERATING INCOME**
- ■ **RATE BASE**
- ■ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- □ **OTHER**

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF
LAUREN R. WHITEHEAD

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1 **I. <u>INTRODUCTION</u>**

2 **Q. Please state your name and business address.**

3 A. My name is Lauren R. Whitehead. My business address is One Monument Circle,
4 Indianapolis, IN 46204.

5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed by AES US Services, LLC as a General & Operational Accounting
7 Manager in the U.S. and Utilities Strategic Business Unit ("U.S. SBU") of The AES
8 Corporation ("AES"), with responsibilities for The Dayton Power & Light Company
9 ("DP&L" or "Company") and other AES businesses.

10 **Q. Please summarize your work experience with AES.**

11 A. I was an employee of DP&L from May 2006 through December 2013. During my tenure
12 with DP&L, I worked in various positions including senior accountant responsible
13 primarily for revenue accounting. In January 2014, I became an employee of AES
14 Services, and I was later promoted to Accounting Supervisor for Indianapolis Power &
15 Light Company ("IPL") General Accounting. I subsequently moved into the position of
16 Accounting Supervisor for AES US Services and all U.S. cost allocations. In 2019, I was
17 promoted into the position of General & Operational Accounting Manager responsible
18 for DP&L, IPL, US Services and AES US Generation.

19 **Q. Will you describe briefly your educational and business background?**

20 A. I earned a Bachelor of Sciences Degree in Accounting and Finance from Wright State
21 University and a Masters of Business Administration from the University of Dayton.

II. PURPOSE OF TESTIMONY

Q. What are the purposes of your testimony in this proceeding?

A. My testimony supports the Actual portion of the following schedules. Forecasted information is supported by Company Witness Hale.

- Schedule B-6 - Addressing Other Rate Base Items
- Schedules B-7 and B-7.1 - The Calculation of Jurisdictional Allocation Factors.
- Schedule B-7.2 - The Explanation of Changes in Allocation Procedures.
- Schedule C-7 - Customer Service and Informational, Sales, and General Expense
- Schedule C-9 - Addressing Operation & Maintenance Payroll Costs of DP&L Employees
- Schedule C-9.1 - Total Company Payroll Analysis By Employee Classifications / Payroll Distribution
- Schedule C-3.16 - Addressing the Inclusion of Interest on Customer Service Deposits.

Q. Were these schedules or portions of these schedules prepared or assembled by you or under your direction or supervision?

A. Yes.

Q. Do you sponsor any workpapers?

A. Yes. My testimony supports the Actual portion of the following Workpapers. Forecasted information is supported by Company Witness Hale.

- Workpaper C-7

- Workpapers C-9, C-9.1, C-9.1a, C-9.1b, and C-9.1c

III. SCHEDULES AND WORKPAPERS

Q. What is shown on Schedule B-6?

A. Schedule B-6 entitled "Other Rate Base Items Summary" summarizes various items included in jurisdictional rate base. I am responsible for the total Company and adjusted jurisdictional customers' deposits balances.

Q. What is the source of the information shown on Schedule B-6?

A. The source of the total Company balance is the general ledger balance of FERC account 235 as of June 30, 2020. This balance consists of deposits held from utility customers as well as deposits held from Competitive Retail Energy Suppliers (CRES). Both are considered to be jurisdictional for this proceeding.

Q. Please describe Schedule B-7, B-7.1, and B-7.2.

A. Schedule B-7 presents the summary of Jurisdictional Allocation Factors, which are derived from information presented on Schedule B-7.1. I am sponsoring all the information on Schedule B-7, and Schedule B-7.1 excluding Distribution Gross Plant and Distribution Net Plant which are sponsored by Company Witness Perrin. Schedule B-7.2 provides an explanation of changes in the allocation procedures.

Q. What is the source of the information shown on Schedule B-7.1?

1 A. Schedule B-7.1 column E and H are populated using historical information from 2019
2 and 2020 from DP&L's SAP General Ledger functional area field. Column E is total
3 Company while column H reflects jurisdictional totals.

4 **Q. Can you describe the process that you used to derive the allocation factors shown on**
5 **Schedule B-7.1?**

6 A. Yes. I acquired the historical detail for the applicable FERC accounts from DP&L's
7 General Ledger. DP&L uses a cost allocation process that captures all expenses in either
8 a Transmission or Distribution cost center. I analyzed the applicable FERC accounts by
9 cost center. I included the amounts recorded in the Distribution cost center in the
10 jurisdictional total. DP&L records all revenues in either a Transmission or Distribution
11 profit center. I analyzed the applicable FERC revenue accounts by profit center. I
12 included amounts recorded in the Distribution profit center in the jurisdictional total. I
13 developed the allocation percentages by dividing the total jurisdictional revenues (or
14 costs) by the total Company revenues (or costs) by FERC account. The resulting
15 percentage is shown in Column I on Schedule B-7.1.

16 **Q. Please describe Schedule C-7.**

17 A. Schedule C-7 presents Customer Service and Informational, Sales, and General Expense
18 for the test period separated into labor and non-labor. This is the information required by
19 OAC, Chapter 4901-7, Section C Instructions, Part D (4). DP&L records all Income
20 Statement activity to both a FERC account and a natural account "Salaries and Wages",
21 "Office Supplies", "Contracted Services", etc. All labor expenses are recorded in labor-

related natural accounts in the general ledger and reported as Labor on Schedule C-7. All other expenses are reported as non-labor.

Q. Please describe Schedule C-9.1.

A. Schedule C-9.1 presents five years of DP&L historical labor hours, labor costs, employee benefit costs and payroll taxes both in total and the amount charged to O&M expense. Year-end and average employee counts are also presented. All information, with the exception of employee benefits and payroll taxes, is also presented broken out between union and non-union. This schedule also includes that information for the unadjusted test year ending May 31, 2021.

Labor hours are identified by straight-time hours and overtime hours. Labor dollars are presented as straight-time dollars, overtime dollars and incentive dollars. Employee benefits have been presented by major component including Pension, Other Post-Employment Benefits, Savings Plan Contributions, Health Benefits and Long-Term Compensation. Labor dollars, Employee Benefits and Payroll taxes are presented as Total DP&L as well as the amount remaining in O&M expense. Benefits and payroll taxes are presented as total DP&L only, because the amounts are not traceable in the general ledger as union versus non-union amounts.

The amount in Column (H), Line 14, which is O&M labor dollars on the first page of Schedule C-9.1, matches Column (C), Line 2 on Schedule C-9. The amount in Column (H), Line 24, on the first page of Schedule C-9.1 matches Column (C), Line 10 on Schedule C-9. The amounts in Column (H), Lines 28, 32 and 36 on the first page of Schedule C-9.1 match Column (C), Lines 14, 15 and 16 on Schedule C-9, respectively.

Q. What was the source for the historic information provided for the years 2015 through 2019 on Schedule C-9.1?

A. The historical information was derived from the books and records of DP&L.

Q. How was the test year information on Schedule C-9.1 derived?

A. The test year consists of twelve months ended May 31, 2021. June, July and August 2020 represent actuals recorded in the DP&L general ledger. The months of September 2020 through May 2021 are forecasted and supported by Company Witness Hale.

Q. Are there filed workpapers supporting the information submitted on Schedule C-9.1?

A. Yes. These workpapers are identified as Workpaper C-9, C-9.1, C-9.1a, C-9.1b and C-9.1c

Q. Please describe Schedule C-9.

A. Schedule C-9 shows total Company unadjusted, jurisdictional unadjusted and jurisdictional adjusted O&M expense for labor, benefits and payroll taxes. Column C depicts unadjusted total Company derived in Schedule C-9.1. Column F depicts the jurisdictional unadjusted derived in WPC-3.13a, WPC-3.13b, WPC-9.1a and WPC-9.1b. The adjustments in Column C are supported by Company Witness Forestal and are derived in WPC-3.13a, WPC-3.13b and WPC-3.14. Column H is the resulting adjusted jurisdictional O&M cost of each respective category.

Q. Moving on to the adjustment schedule, please continue and describe Schedule C-3.16.

1 A. Schedule C-3.16 calculates a 3% interest expense on the date certain jurisdictional
2 customer deposit balance held by the Company. Ohio Revised Code § 4933.17
3 establishes that 3% is the minimum interest rate an Ohio utility is required to pay to
4 customers on deposits. I obtained the customer deposit balance from the Company's
5 Customer Service System and verified that amount against a general ledger balance. This
6 jurisdictional adjustment results in an increase of $412,960 in O&M expense in the test
7 year. Because interest on customer deposits is not part of test year operating expenses, the
8 full amount must be added to test year operating expenses for DP&L's revenue
9 requirement to include recovery of this cost.

10 **IV. CONCLUSION**

11 Q. **Is the information provided on the Schedules and Workpapers you sponsor accurate**
12 **to the best of your knowledge and belief?**
13 A. Yes.

14 **Q. Does that conclude your direct testimony?**
15 A. Yes.

16 1467561.1

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing document has been served via electronic mail upon the following counsel of record, this 14th day of December, 2020:

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Summary: Application Application Book III - Testimony, Volume 4 of 4 (Tyler A. Teuscher, Mark L. Vest, C. Kenneth Vogl, and Lauren R. Whitehead) electronically filed by Mr. Jeffrey S Sharkey on behalf of The Dayton Power and Light Company