OCC EXHIBIT _____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of the Application of Dayton Power and Light Company for Approval of Its Plan to Modernize Its Distribution Grid.	)	Case No. 18-1875-EL-GRD
In the Matter of the Application of the Dayton Power and Light Company for Approval of A Limited Waiver of Ohio Adm. Code 4901:1-18-06(A)(2).	)	Case No. 18-1876-EL-WVR
In the Matter of the Application of the Dayton Power and Light Company for Approval of Certain Accounting Methods.	)	Case No. 18-1877-EL-AAM
In the Matter of the Application of the Dayton Power and Light Company for Administration of the Significantly Excessive Earnings Test under R.C. 4928.143(F) and Ohio Adm. Code 4901:1-35-10 for 2018.	)	Case No. 19-1121-EL-UNC
In the Matter of the Application of the Dayton Power and Light Company for A Finding That Its Current Electric Security Plan Passes the Significantly Excessive Earnings Test and More Favorable in the Aggregate Test in R.C. 4928.143(E).	)	Case No. 20-680-EL-UNC
In the Matter of the Application of the Dayton Power and Light Company for Administration of the Significantly Excessive Earnings Test under R.C. 4928.143(F) and Ohio Adm. Code 4901:1-35-10 for 2019.	)	Case No. 20-1041-EL-UNC

PUBLIC VERSION

DIRECT TESTIMONY
OF
PAUL J. ALVAREZ

PRESIDENT, WIRED GROUP

IN OPPOSITION TO THE JOINT STIPULATION AND RECOMMENDATION

On Behalf of
The Office of the Ohio Consumers' Counsel
65 East State Street, 7th Floor
Columbus, Ohio 43215

December 17, 2020

TABLE OF CONTENTS

PAGE

I. INTRODUCTION, PURPOSE, AND PREVIEW 1

II. DP&L'S SGP, AS PROPOSED AND REVISED IN THE STIPULATION, WILL NOT DELIVER BENEFITS IN EXCESS OF COSTS TO CUSTOMERS, AND IS PARTICULARLY HARMFUL TO RESIDENTIAL CUSTOMERS. 11

III. CUSTOMERS BEAR 100% OF THE RISK OF DP&L'S SGP INVESTMENTS, AND STIPULATED PERFORMANCE MEASURES ARE INADEQUATE, VIOLATING CUSTOMER AND PUBLIC INTERESTS. 35

IV. THE STIPULATION ALLOWS FOR PHASE 2 INVESTMENTS BEFORE THE SUCCESS OF PHASE 1 CAN BE DETERMINED. 46

V. SUMMARY AND RECOMMENDATIONS.....51

ATTACHMENTS

PJA-01. DP&L Response to OCC RPD-1-08(b), Attachment 1 DP&L_GRD_0000989.xlsx, Exhibit 2, WP-1.1.

PJA-02. DP&L Response to PUCO Staff DR 1-01, Attachment DP&L_GRD_000003.xlsx, Tab WP-1.3, WP-A, WP-B, WP-C.

PJA-03. DP&L Response to OCC INT 1-34

PJA-04. DP&L Response to OCC RPD 1-06, Attachment DP&L_GRD_0000983.xlsx, Tab WP-A, Tab WP-B, Tab WP-C, Cost-Benefit Detailed Summary Confidential

APPENDICES

A. Curriculum Vitae -- Paul J. Alvarez MM, NPDP

[redacted]

I. INTRODUCTION, PURPOSE, AND PREVIEW

Q1. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A1. My full name is Paul J. Alvarez. My business address is Wired Group, Post Office Box 620756, Littleton, Colorado 80162.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A2. I am the President of the Wired Group, a consultancy specializing in distribution utility planning, investment, and performance measurement.

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A3. My career in the electric utility industry began 20 years ago with Xcel Energy, one of the largest investor-owned utilities in the U.S. After a series of product management roles of progressive responsibility for large corporations, including Motorola's Communications Division (now owned by Google), Baxter Healthcare, Searle Pharmaceuticals, and Walgreens, I served Xcel Energy as product development manager. In this role I oversaw the development of new demand-side management (DSM) programs for residential and commercial and industrial customers, as well as rates and programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

In 2008 I left Xcel Energy to establish a utility practice for boutique sustainability consulting firm MetaVu. While at MetaVu I utilized the DSM program benefit measurement and verification (M&V) experience I gained at Xcel Energy to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are two of only four comprehensive, unbiased evaluations of smart grid deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain, including an evaluation of the SmartGridCity™ deployment in Boulder, Colorado completed for Xcel Energy in 2010,[1] and an evaluation of Duke Energy's Cincinnati-area deployment completed for the Public Utilities Commission of Ohio Staff in 2011.[2]

I started the Wired Group in 2012 to focus exclusively on distribution utility planning, investment, and performance measurement. Wired Group clients include consumer, business, and environmental advocates. Since 2012 I have testified in scores of distribution business proceedings before 15 state utility regulators and supported clients in their distribution grid work before six other state utility regulators. In addition to leading the Wired Group, I teach post-graduate courses based on my experience. I teach "Renewable Energy Commercialization: Electric Technologies, Markets, and Policy" at the University

[1] *SmartGridCity™ Demonstration Project Evaluation Summary*. Exhibit MGL-1 to the testimony of Michael G. Lamb in the Matter of the Public Service Company of Colorado Application for Approval of SmartGridCity Cost Recovery. Filed with the Colorado PUC in 11A-1001E on December 14, 2011. Alvarez et al. Report dated October 21, 2011.

[2] *Duke Energy Ohio Smart Grid Audit and Assessment*. Public Utilities Commission of Ohio Staff Report, public version, filed in 10-2326-GE-RDR on June 30, 2011. Alvarez et al. ("Duke Energy Mid-Term Review").

of Colorado's Global Energy Management Program. I also teach sessions on distribution utility performance measurement and grid modernization value creation at Michigan State University's Institute for Public Utilities, a program dedicated to educating new regulators and staff on utility industry concepts.

I am also the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Now in its second edition, the book describes the challenges of translating smart grid investments into economic and environmental benefits for customers, and offers organizational, operational, customer engagement, rate design, and regulatory solutions. Finally, I am the developer of the *Utility Evaluator*™, an internet-based software application which uses publicly available financial and operating data to benchmark U.S. distribution utility performance. I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree from the Kellogg School of Management at Northwestern University in 1991. Both degrees featured concentrations in finance and marketing.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A4. Yes. I testified on behalf of the Office of Ohio Consumers' Counsel ("OCC") against the Joint Stipulation and Recommendation in PUCO 17-0032-EL-AIR, in which Duke Energy first proposed to replace the smart meters and systems it had installed just a few years

1 prior.[3] I also appeared before the PUCO in the Power Forward proceedings, making a
2 presentation entitled "Getting a Smart Grid for Free."[4] The presentation, like my book and
3 this testimony, focused on the many challenges that must be overcome if the benefits of
4 grid modernization are to exceed costs to customers. Finally, as mentioned above, I led the
5 team which prepared the Duke Energy Ohio Smart Grid Audit and Assessment, entered
6 into the record in PUC 10-2326-GE-RDR on June 30, 2011. This report is known generally
7 by Staff and stakeholders as the "mid-term review" concerning Duke Energy Ohio's first
8 grid modernization deployment. My full CV is provided as Appendix A to this testimony.
9
10 ***Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?***
11 ***A5.*** I am testifying on behalf of the OCC regarding the Joint Stipulation and Recommendation
12 ("Settlement") reached between the Dayton Power and Light Company ("DP&L", or "the
13 Utility") and multiple stakeholders dated October 23, 2020.[5] The Settlement authorizes
14 DP&L to invest hundreds of millions of dollars in its distribution grid, and to collect the
15 majority of associated costs from customers through the Infrastructure Investment Rider
16 ("IIR"), approved by the PUCO as part of DP&L's ESP III. I have examined the
17 Settlement and all materials related to DP&L's Smart Grid Plan ("SGP") filed in PUC 18-
18 1875-EL-GRD, including the initial Application, discovery, and subsequent updates.

[3] PUCO 17-0032-EL-AIR et al. Revised Direct Testimony of Paul J. Alvarez dated June 25, 2018.

[4] Alvarez P. "*Getting a Smart Grid for Free*". Presentation in Phase 2 (Exploring Technologies) of the PUCO Power Forward investigation. July 26, 2017.

[5] PUCO 18-1875-EL-GRD et al. Stipulation and Recommendation dated October 23, 2020. ("Settlement").

The purpose of my testimony is to describe the results of my examination, and to make a recommendation to the PUCO regarding the Settlement. I understand the PUCO uses a three-part test to evaluate whether to approve a settlement, one of which is "does the settlement, as a package, benefit customers and the public interest?" Based on my examination of the materials in this case, and my experience regarding the plans, regulatory policies, and performance measures required to ensure that smart meter and smart grid benefits exceed customer costs, I recommend the PUCO reject the Settlement because it does not benefit customers, nor is it in the public interest. There are a number of reasons I come to this conclusion.

Q6. PLEASE PROVIDE A PREVIEW OF YOUR TESTIMONY.

A6. My testimony explains how the Settlement does not benefit customers or the public interest. Here are the reasons why:

- DP&L's SGP, as proposed and revised in the Settlement, will not deliver benefits in excess of costs to customers, and is particularly harmful to residential customers.
- Customers bear 100% of the risk of DP&L's SGP investments, and stipulated performance measures are inadequate, to the detriments of customers and the public interest.
- The Settlement allows for Phase 2 investments (and resulting charges to customers) before the success of Phase 1 can be determined.

In the Summary and Recommendations, I provide basic, pragmatic ideas on how the PUCO might increase the benefits customers receive from grid modernization investments. These ideas apply to all grid modernization investments, but also to DP&L's SGP, as modified by the Settlement.

Q7. PLEASE PROVIDE A PREVIEW OF THESE BASIC, PRAGMATIC IDEAS TO INCREASE THE BENEFITS CUSTOMERS RECEIVE FROM GRID MODERNIZATION INVESTMENTS, AND FROM DP&L'S SGP.

A7. While I believe the Settlement is harmful to customers and not in the public interest, and recommend the PUCO reject it, I understand that generally the PUCO can approve and modify a Settlement. If the PUCO approves this Settlement over OCC objections, the PUCO should modify the Settlement to add the following consumer protections:

- Allocate grid modernization costs among customer classes in relation to benefits delivered. As the economic benefits of reliability improvements are among the largest of those potentially available from grid modernization, and as these skew dramatically to commercial & industrial ("C&I") customers, C&I customers should bear a greater burden for grid modernization cost recovery relative to routine cost recovery. While the Settlement specifies current cost allocations by class -- 33.7% for C&I – DP&L expects C&I customers to secure 96% of the economic benefits

from reliability improvements. The PUCO has approved smart grid programs where the costs were more fairly allocated by customer class.[6]

- Establish guidelines for grid modernization cost-benefit analyses. These guidelines should specify carrying charges that are included; the stranded costs that are included; the types of capabilities and benefits the PUCO requires; how to value reliability improvements; and the types of benefits the PUCO will not consider, such as indirect/societal benefits (unless accompanied by indirect/societal costs).
- Conduct "willingness to pay" research among various customer classes. Understand what customers would be willing to pay for various levels of reliability improvement, and take this into account when evaluating utility grid modernization or reliability improvement plans.
- Sponsor an independent research project intended to estimate the economic impact of service interruptions of various durations to communities. Require utilities to use these research results in any attempts to quantify the economic benefits of reliability improvements as part of cost-benefit analyses.
- Address the rate case timing issue. Make certain that grid modernization plans include estimates for the year by which all benefits will be reflected in a utility's books and records and specify the timing for a rate case using that year as a test year. This will benefit customers by synchronizing the Utility's request to increase distribution costs for the smart grid to customers at the same time the benefits of

[6] *In the Matter of the Application of Ohio Power Company to Initiate Phase 2 of its gridSMART Project and to Establish the gridSMART Phase 2 Rider, Case No. 13-1939-EL-RDR.Opinion and Order (February 1, 2017).*

the smart grid are available for comparison. The PUCO should not approve distribution costs in excess of the benefits of the smart grid.

- Make certain that grid modernization investment risk is shared between utilities and customers. Establish utility consequences for failure to deliver the level of benefits projected as called for in the PUCO's own Power Forward Roadmap final report.
- Measure benefits in a post-deployment benefit evaluation as called for in the PUCO's own Power Forward Roadmap final report.
- Prevent a utility from making additional grid modernization investments until the customer benefits from investments it has already made (that customers have and are being charged for) have been measured and shown to be in excess of costs to customers.
- Ensure reliability improvement metrics employ the same structure specified in Ohio standards, currently system average interruption frequency index (SAIFI) and customer average interruption frequency index (CAIDI). Inconsistencies in the Settlement fail to hold DP&L accountable for interruption duration improvement.

Q8. CAN YOU PLEASE PROVIDE YOUR OVERALL IMPRESSION OF THE STATE OF SMART METER AND SMART GRID INVESTMENTS IN THE UNITED STATES TODAY?

A8. I understand the PUCO is anxious to secure the potential benefits available from smart meters and smart grids. I would like to see customers get those benefits too. However, simply making these investments does not equate to benefit delivery. The maximization

of benefits from these investments for customers requires extensive efforts from utilities, customers, and regulators (in the form of the recommendations listed above). A technology deployment plan which fails to specify those efforts will not deliver benefits to customers in excess of costs to customers and must be rejected. DP&L's plan is an example of a smart grid plan which fails to specify required efforts.

Unlike the benefits of most types of utility investments, such as power plants, substations, or utility poles, smart meter and smart grid benefits vary widely from utility to utility. My research and experience indicate that smart meter and smart grid benefits to customers fall dramatically without sound decisions and extensive efforts from regulators in both the planning and post-deployment phases of grid modernization investment. In my expert opinion, no grid modernization investment should proceed without 1) a clear understanding of conservatively estimated customer costs and customer benefits; 2) a clear plan to maximize all available benefits; and 3) a clearly defined outcomes measurement program. DP&L's smart grid plan ("SGP"), as originally proposed and as modified by the Settlement, fails on all three counts.

Q9. SO, YOU DO NOT OPPOSE SMART METER OR SMART GRID INVESTMENTS?

A9. Of course not. I appreciate the vision, and that much of that vision is future state and difficult to quantify. But customers expect, and Ohio policy (and law) demands, that utilities and regulators work towards a common goal: safe, reliable, reasonably priced retail

electric service.[7] DP&L's SGP as represented in the Settlement is a missed opportunity to secure a modern grid at little or no incremental costs to customers.

Through the Power Forward investigation, the PUCO has done much more than most commissions to establish a vision for the future of its state's electric distribution grids, utilities, and regulation. However, in cases like this one, I believe the PUCO's focus must shift from vision to execution. Indeed, a growing number of state commissions are recognizing that the execution phase of grid modernization is being botched.[8] A rejection of the Settlement is not an indictment of the PUCO's vision; it would simply represent a recognition that DP&L's SGP is not in the best interest of customers, and that DP&L must do more to cost-effectively achieve the PUCO's vision for customers.

[7] Ohio Revised Code 4928.02(A).

[8] Trabish, H. Slowed Pay-off From Billions in AMI Investment Puts the Technology's Future in Doubt. Blog Post, Utility Dive, February 20, 2020 (https://www.utilitydive.com/news/slowed-pay-off-from-billions-in-ami-investment-put-the-technologys-future/570274/). *Also*, Utilities Vastly Underutilizing Smart Meter Technology – Report. Blog Post. Smart Energy International. January 13, 2020 (https://www.smart-energy.com/industry-sectors/smart-meters/utilities-vastly-underutilising-smart-meter-technology-report/). Also, Walton, R. Most Utilities Aren't Getting Full Value from Smart Meters, Report Warns. Blog Post. Utility Dive, January 13, 2020. (https://www.utilitydive.com/news/most-utilities-arent-getting-full-value-from-smart-meters-report-warns/570249/).

II. DP&L'S SGP, AS PROPOSED AND REVISED IN THE SETTLEMENT, WILL NOT DELIVER BENEFITS TO CUSTOMERS THAT EXCEED COSTS TO CUSTOMERS, AND IS PARTICULARLY HARMFUL TO RESIDENTIAL CUSTOMERS.

Q10. PLEASE PREVIEW YOUR TESTIMONY REGARDING THE COST-BENEFIT ANALYSIS DP&L PROVIDED WITH THE SETTLEMENT.

A10. The cost-benefit analysis provided with the Settlement projects that DP&L benefits will exceed DP&L costs by a wide margin. Unfortunately, a cost-benefit analysis developed from DP&L's point of view is entirely different from a cost-benefit analysis prepared from a customer perspective.

A customer-centric cost-benefit analysis compares the costs customers will actually pay for the SGP to the benefits customers will actually recognize from the SGP. A customer-centric, cost-benefit analysis takes into account the timing of customer benefit recognition, and appropriately treats indirect benefits as inferior to direct benefits.

Using DP&L's own projections, I developed a cost-benefit analysis from a customer perspective, adjusting for costs customers will pay, which DP&L excluded from its analysis, such as carrying charges. I also made three benefit adjustments to reflect customer realities, including adjustments for rate case timing (which could delay SGP-related rate reductions to customers for decades); exaggerated benefits; and indirect benefits customers

will not realize. I'll also discuss why DP&L's reliability improvement benefits are unrealistic, although to be conservative, I stop short of making any benefit adjustments for the concerns I cite.

In total, after making appropriate adjustments to DP&L's cost-benefit analysis, I calculate that customers will receive just $0.45 in benefits for every $1 paid to DP&L for its SGP (in present value terms), even with no adjustments for reliability benefits I believe to be overstated. Finally, I explain why the cost-to-benefit ratio for residential customers is even worse than the $1 to $0.45 ratio for customers overall. In support of these claims, this section of testimony is organized as follows:

A. Adjustments to DP&L Costs (missing carrying charges, information technology costs, and payments customers will make on equipment removed from service);
B. Adjustments to DP&L Benefits (the rate case timing issue; exaggerated benefits; and indirect benefits customers will not realize);
C. Concerns that Reliability Benefits Are Unrealistic (from both technical and economic perspectives);
D. Summary: Costs and Benefits from a Customer Perspective; and
E. Summary: Costs and Benefits for Specific to Residential Customers.

A. Adjustments to DP&L Costs

Q11. IN WHAT WAYS DOES DP&L'S COST-BENEFIT ANALYSIS UNDERESTIMATE COSTS TO CUSTOMERS?

A11. DP&L's cost-benefit analysis underestimates costs to customers in three ways. Most significantly, DP&L's costs do not include carrying charges customers will pay for the SGP, which I estimate will cost $180 million over the 20-year SGP cost-benefit analysis period. In addition, DP&L's cost-benefit analysis excludes $96.5 million in information technology costs required for foundational smart meter capabilities, in the form of a new Customer Information System. DP&L's cost-benefit analysis also excludes over $9 million in undepreciated book value of meters removed from service prematurely to make way for smart meters. I provide details on these adjustments to DP&L's cost projections in Appendix B.

Q12. DP&L DID NOT INCLUDE THE CARRYING CHARGES CUSTOMERS MUST PAY IN ITS COST-BENEFIT ANALYSIS?

A12. No, it did not. Though the carrying charges customers mut pay – including DP&L profits, income taxes on those profits, interest expense on debt, and property taxes – are enormous over the 20-year benefit period DP&L used in its cost-benefit analysis, DP&L did not include carrying charges in its analysis. I note that neither DP&L's original SGP application nor the Settlement estimates the total costs customers will pay for the SGP over time, including carrying charges, even when requested in discovery.[9]

[9] PUC 18-1875-EL-GRD et al. DP&L response to Settlement discovery OCC-RPD-1-8(b) (attached herein as PJA-01).

Q13. HAVE YOU ESTIMATED THE TOTAL CARRYING CHARGES CUSTOMERS WILL PAY FOR THE SGP AS PROPOSED, AND AS MODIFIED BY THE SETTLEMENT?

A13. Yes. I estimate the carrying charges customers will pay on the SGP as proposed, and as modified by the Settlement, will be $180 million in nominal value and $21 million in present value over the 20-year period DP&L used in its cost-benefit analysis.

Q14. WHAT HAPPENED TO THE INFORMATION TECHNOLOGY INVESTMENTS PROPOSED IN THE ORIGINAL APPLICATION?

A14. The SGP DP&L originally proposed included capital costs of $54.3 million for a new customer information system (CIS).[10] The new CIS is essential for enabling some of the largest potential customer benefits from smart meters, including time-varying rates and energy conservation support (via online portals, detailed usage data access, high bill alerts, and other features). DP&L removed the cost of the CIS, along with corresponding time of use ("TOU") rate and energy conservation benefits, from its cost-benefit analysis.

However, the Settlement still requires DP&L to make these information technology investments,[11] meaning that customers will still pay for them. I find this extremely misleading. Not only does the removal of these information technology investments from

[10] PUCO 18-1875-EL-GRD. DP&L_GRD_0000003.xlsx. DP&L response to Staff DR 1-01. Tab WP-1.3 CIS. (attached herein as PJA-02).

[11] Settlement, p 20, Section 10 (CIS); p 28, Section 11.c.i (MDMS).

the cost-benefit analysis understate SGP costs to customers, it also absolves DP&L of any responsibility for securing associated benefits promised by DP&L in its original SGP application. (I will return to this issue later in my testimony.) I estimate the total cost of this understatement, including O&M and carrying charges related to the new CIS, to be $96.5 million.

Q15. HOW DO DP&L COST ESTIMATES EXCLUDE $9 MILLION IN UNDEPRECIATED BOOK VALUE OF EXISTING METERS REMOVED PREMATURELY TO MAKE WAY FOR SMART METERS?

A15. In the current Settlement, it was agreed that the undepreciated book value of equipment removed from service will be subtracted from gross plant additions, and that this gross plant offset will occur through the IIR as the equipment is retired.[12] DP&L's cost-benefit analysis reflects four years of such offsets, amounting to $18.3 million, as DP&L expects the IIR to be in place for four years. However, workpapers indicate that the net book value of equipment to be removed from service prematurely is $27.5 million,[13] meaning that $9.2 million in book value of equipment that is no longer used and useful will remain in rate base, and customers will pay for both carrying charges and depreciation on that remaining book value over time. Customers should not be paying for equipment that is no longer used

[12] Settlement, page 6, Section 3.e.ii.

[13] *See* PJA-01: DP&L_GRD_000989.xlsx, provided by DP&L in Settlement discovery in response to OCC-RPD-1-8(a). ("DP&L Stipulation IIR Revenue Requirement Workpaper"). Tab "WP-1.1 AMI Capital", cell N45.

and useful. If a utility plans to charge for such equipment, as DP&L appears to, such costs should be considered in a cost-benefit analysis.

B. Adjustments to DP&L Benefits

Q16. IN WHAT WAYS DOES DP&L'S COST-BENEFIT ANALYSIS OVERSTATE THE BENEFITS CUSTOMERS WILL RECEIVE?

A16. DP&L's cost-benefit analysis overstates the benefits customers will receive in at least four significant ways. One of these relates to the way that many types of SGP benefits are reflected in rates customers pay. In brief, while the Utility gets the economic benefits of SGP-related O&M savings and revenue improvements as specific actions are taken, these benefits only result in rate reductions for consumers if those benefits are captured through a rate case filing. Because DP&L controls both rate case timing and the timing of many SGP benefits, this becomes a problem for customers, who are paying rate increases now on the assets with shareholders reaping the benefits.

The Settlement recognizes this issue, in part, by requiring that operational benefits DP&L projects be offset against the IIR revenue requirement. But significantly, the Settlement does not address the continuation of the operational benefit offset beyond year four. As a result, my benefit adjustments assume DP&L will discontinue the offset of IIR revenue requirements by the amount of projected operational benefits once the Stipulated offset amounts are exhausted (year four).

Third, DP&L exaggerates some benefits. As just one example, the DP&L cost-benefit analysis employs benefit periods that are longer than the expected useful lives of the assets which generate those benefits. Though smart meters are only likely to last 12-15 years, DP&L assumes a 20-year benefit period for smart meter-related capabilities. In doing so, DP&L overstates the benefits to customers.

Fourth, the inclusion of several types of indirect benefits in a cost-benefit analysis is inappropriate for a variety of reasons; I will explain why this is the case for electric vehicle fuel savings, the economic impact of DP&L spending, and the economic value of greenhouse gas emission reductions. I provide details of all these adjustments to DP&L's benefit projections in Appendix C.

Q17. PLEASE BEGIN BY PROVIDING MORE INFORMATION ON THE RATE CASE TIMING ISSUE, AND WHY CONSUMERS MAY NOT OBTAIN THE OPERATIONAL BENEITS FROM SMART GRID INVESTMENTS.

A17. As the PUCO is well aware, investor-owned utilities are quick to file a rate case during times of rising costs; a rate case is the traditional way utilities recover rising costs through rate increases to consumers. As long as rate bases are holding steady, when costs are falling and/or revenues are rising, utilities are unlikely to file a rate case, as to do so would transfer the benefits of falling costs and/or growing revenues from shareholders to customers (in the form of rate decreases). This is likely the reason why DP&L failed to file a rate case for almost 25 years after its 1991 rate case; its success in reducing costs,

as well as increasing revenues, were providing benefits to shareholders, at a time when rate bases were holding steady.

The takeaways are that 1.) effectively implemented smart grid programs reduce utility operating costs and increase revenues; and 2) a rate case is required before falling costs and increasing revenues can be translated into customer rate reductions. Falling costs and increasing revenues which are expected in the future, but which are not yet reflected in a rate case's test year, will benefit shareholders until some subsequent rate case. DP&L controls the timing of many SGP benefits, as well as the timing of the subsequent rate case and the sharing of the benefits with consumers. Absent PUCO action, consumers have no protection against utility manipulation and delay in providing benefits and lower costs to consumers.

Q18. DOES THE SETTLEMENT REQUIRE THAT A RATE CASE BE FILED IN 2024?

A18. No, it does not. The Settlement states "If DP&L does not file a distribution rate case by January 1, 2025, then the recovery of the costs associated with this Settlement shall cease recovery and the IIR shall be set to zero." As the Settlement is dated October 23, 2020 and DP&L filed a rate case application on November 30, 2020, the action required under the Settlement to avoid IIR discontinuation appears to have already been met. It is therefore quite possible, if not likely, that the new IIR will continue indefinitely, providing SGP cost recovery to DP&L without the rate case, which would deliver rate reductions to customers.

Q19. WOULD A STIPULATION THAT A RATE CASE BE FILED IN 2024 CURE THE RATE CASE TIMING ISSUE?

A19. No, it would not. Any rate case DP&L would file by January 1, 2025, which would presumably use calendar year 2024 (or some portion) as a test year, would still not likely reflect large amounts of O&M reduction and revenue improvement benefits, resulting in a smaller rate decrease than DP&L benefit projections suggest. So, even if the PUCO were to determine that the rate case DP&L filed on November 30 does not meet this Settlement requirement, thus eliminating the IIR at that point and essentially forcing a rate case, my rate case timing benefit adjustment would still be necessary.

Q20. THE FACT THAT THE RATE CASE DP&L FILED ON NOVEMBER 30TH WOULD FAIL TO INCLUDE SGP BENEFITS IS UNDERSTANDABLE. BUT PLEASE EXPLAIN WHY A RATE CASE USING 2024 AS A TEST YEAR WOULDN'T INCLUDE O&M REDUCTION AND REVENUE IMPROVEMENT BENEFITS FOR CUSTOMERS.

A20. If a rate case were to be filed using 2024 as a test year, some amount of O&M reductions, including large ones, like meter reading and theft reduction, would be included. This is because the count of meter readers, and theft detection outcomes, are metrics established in the Settlement, and DP&L will likely attempt to hit those metrics. But metrics for other O&M reductions, and some revenue improvements, are not as specific. This means that the timing of these benefits can be manipulated by DP&L such that they occur after the test year. Benefits from capabilities implemented and actions taken after the next test year will

1 accrue to shareholders, not customers, until some subsequent rate case. DP&L shareholders
2 might benefit from this situation for decades, as was the case when DP&L failed to file a
3 rate case from 1991 to 2015.
4
5 ***Q21. DID YOU ESTIMATE THE IMPACT OF THE RATE CASE TIMING ISSUE?***
6 ***A21.*** Yes. To estimate the impact of the rate case timing issue, I had to assume a date for DP&L's
7 next rate case. If the Settlement were to be approved, I am assuming that DP&L will not
8 file another rate case for the duration of the SGP cost-benefit analysis period (meaning,
9 through 2040). My assumption is based on three facts: 1) the Settlement specifies no future
10 rate case; 2) DP&L appears to have already satisfied the requirement to avoid IIR
11 discontinuation, meaning that SGP cost recovery can continue without a rate case;[14] and 3)
12 shareholders benefit when DP&L avoids filing a rate case during times of falling
13 costs/growing revenues.
14
15 With a rate case timing assumption established, my benefit adjustment calculation turns to
16 those benefits which 1) will accrue to shareholders, not customers, until reflected in a rate
17 case's test year books and records; and 2) are not the subject of a rigorously defined
18 outcome metric in the Settlement (indicating that benefit timing is malleable). These
19 benefits include: 1) customer contact center headcount reductions; 2) meter services (not

[14] I note that riders allow capital cost recovery without a rate case. The fact that riders allow capital cost recovery without a simultaneous examination of expenses which may have fallen is a principal reason why consumer advocates and experts, including myself, oppose the use of riders entirely.

meter reading) headcount reductions; 3) field crew headcount reductions; and 4) unbilled pole attachments. In years 5-20 of DP&L's cost-benefit analysis, these benefits, which will accrue to shareholders, not customers, amount to $4.5 million annually to start, and grow over time due to inflation. Over this period, I estimate customers will miss out on $85 million of benefits DP&L includes in its cost-benefit analysis due to rate case timing. That $85 million would create a windfall to investors that is funded by customers.

Q22. WHY DID YOU EXCLUDE BENEFITS IN COST-BENEFIT ANALYSIS YEARS 1-4 FROM YOUR RATE CASE TIMING ADJUSTMENT?

A22. Because the Settlement states "DP&L's recovery of its capital investments and expenses through the IIR shall be offset by the estimated operational benefits that the parties agree DP&L will realize as a result of DP&L's SGP (DMP) Phase 1 expenditures." On Settlement Exhibit 2, line 16, the "estimated operational benefits that the parties agree DP&L will realize" totals $7.6 million in years 1-4. As a result of this mechanism, no rate case timing issue exists in years 1-4, and no benefit adjustment is required for years 1-4. However, this question brings me to my next benefit adjustment: no stipulated commitment to continue the operational benefit offset beyond year four.

Q23. THERE WILL BE NO OPERATIONAL BENEFIT OFFSET BEYOND YEAR FOUR?

A23. Not according to the Settlement, no. When pressed on this issue in discovery, DP&L refused to address it.[15] If the Settlement required a rate case which specified a test year reflective of O&M reductions and revenue improvements, the failure to continue the operating benefit offsets would be less of an issue, as such benefits would be captured for customers through rate decreases. But since the Settlement does not specify such a rate case, nor the continuation of the operating benefit offset, I make a benefit adjustment reflecting these facts.

Q24. HOW DID YOU ESTIMATE THIS BENEFIT ADJUSTMENT?

A24. Some of the O&M reduction/revenue improvement items for which I would make this adjustment are already accounted for in the rate case timing adjustment I described earlier. Benefits lost to customers without either a benefit offset or an appropriately-timed rate case, which are not already accounted for in my rate case timing adjustment, include 1) meter reading; 2) meter accuracy; 3) residential theft; 4) small C&I theft; and 5) usage on inactive meters. These benefits, which will accrue to shareholders, not customers, amount to $6.6 million annually to start, and grow over time due to inflation. In cost-benefit analysis years 5-20, I estimate customers will miss out on $146 million of benefits DP&L includes in its cost-benefit analysis due to a lack of either a benefit offset or an appropriately-timed rate case.

[15] DP&L response to OCC Settlement interrogatory INT-1-34 (attached herein as PJA-03).

Q25. YOU MENTIONED THAT DP&L EXAGGERATES CUSTOMER BENEFITS IN ITS COST-BENEFIT ANALYSIS. CAN YOU PROVIDE EXAMPLES?

A25. As mentioned in the introduction to this topic, DP&L applies a 20-year benefit period to smart meter benefits, though smart meters are only expected to last 12-15 years.[16] (Duke Energy is replacing all its Ohio smart meters after only 5-7 years of operation, and the Settlement requires DP&L to depreciate smart meters over 15 years.) As a result, a downward adjustment of benefits anticipated from smart meters in years 16-20 is appropriate. As another example, DP&L claims its geographic information system (GIS) software will increase pole attachment revenues by [redacted] 20 years,[17] though even significant software packages like GIS are only expected to last 5-10 years before requiring replacement.

There are more examples. For instance, DP&L claims its SGP will reduce capital for equipment inventory by [redacted] to [redacted] annually for 20 years.[18] In reality, as a working capital item, equipment inventory is something that can be reduced only once; such reductions do not repeat (or grow) annually, as the DP&L benefit estimate suggests. In another example, the O&M savings estimate DP&L calculates from smart meters' remote disconnect/reconnect capabilities assumes that the Utility's request for a waiver of

[16] Kelly M and Elberg R. "AMI Gold Standards Report – An Assessment of the Smart Electric Metering Landscape". Navigant Research report to the New Jersey Board of Public Utilities. Page 33. Q4, 2019.

[17] PUCO 18-1875-EL-GRD. DP&L_GRD_0000983.xlsx. Confidential workpaper provided in Settlement discovery to OCC-RPD-1-6. ("Stipulation benefit-cost analysis") Tab "WP_A Utility Benefits". (attached herein as PJA-04).

[18] Ibid.

the "door knock requirement" has been approved. However, such a waiver may not be approved, and is certainly not in the interest of customer safety. Combined, these exaggerations account for $63.7 million of the benefits in DP&L's cost-benefit analysis. However, all these exaggerations but one (the equipment inventory reduction) are already accounted for in the previous benefit adjustments I discussed. I did make an adjustment for the equipment inventory reduction exaggeration.

Q26. CAN YOU EXPLAIN WHY INDIRECT BENEFITS, LIKE ELECTRIC VEHICLE FUEL SAVINGS, GREENHOUSE GAS EMISSION REDUCTIONS, AND ECONOMIC BENEFITS OF DP&L SPENDING, ARE INAPPROPRIATE FOR A COST-BENEFIT ANALYSIS?

A26. Each is inappropriate to include in a cost-benefit analysis for its own reasons; some are inappropriate to include for several reasons. But before addressing these indirect benefits individually, I'd like to describe some overall concerns related to the inclusion of indirect benefits in cost-benefit analyses generally. My principal concern is that indirect benefits should not be included in a cost-benefit analysis unless indirect costs are also included. For many DP&L customers, electric rate increases result in reduced food or medical purchases, reduced health and productivity, and a reduction in quality of life; I do not see any of these indirect costs included in DP&L's cost-benefit analysis.

Another reason indirect benefits should not be used to justify direct costs is the notion of equivalency. Though the receipt of indirect benefits is a nice thing for customers, the notion

that a dollar of indirect benefit is equivalent to a dollar of direct benefit is nonsense. Any customer would rather have a direct benefit with which to offset a direct cost (rate increase) when such opportunities are available. But unfortunately, the Settlement as it stands leaves large amounts of potential direct economic benefits for customers on the table. This leads me to another point for PUCO consideration: I consider the use of indirect benefits to justify direct costs to be missed opportunities to demand greater direct benefits for customers.

Q27. WHY SHOULD EV FUEL COST SAVINGS BE EXCLUDED FROM DP&L'S COST-BENEFIT ANALYSIS?

A27. There are multiple reasons. The first is that DP&L's charger rebate program is not likely to be a significant driver of EV adoption. EV prices and the cost of gasoline are far bigger drivers, and multiple studies indicate that 95% of EV charging occurs at home. The second reason is that market forces will intervene with or without DP&L's charger rebate program. For example, a multi-family building landlord, once she equates a lack of charging stations with a lack of tenants, will install them, much as landlords build garages or car ports for tenants' vehicles today. The third reason is that only some customers will benefit from charger rebates. Customers as a whole will not receive benefits in the manner that customers may receive from demand-side management programs, or from rate decreases, or from reliability improvements. The notion that all customers, including low-income customers, will be subsidizing customers with the resources to buy a new electric vehicle is a clear violation of the cost-causation principle. Finally, the notion that DP&L should

get credit for the fuel cost differential between gasoline and electricity, when customers are the ones putting up the vast majority of capital required to secure the benefit, is dubious at best.

Q28. WHAT ABOUT THE FAVORABLE ECONOMIC IMPACT OF DP&L SGP SPENDING? ISN'T THAT A REASONABLE INDIRECT BENEFIT TO INCLUDE IN A COST-BENEFIT ANALYSIS?

A28. No, for the simple reason that it is inappropriate to include a benefit without also considering corresponding costs. DP&L's benefits include the favorable impact of its spending on the local economy, but DP&L's costs do include the detrimental impact to the local economy of 15-50 years of SGP-related rate increases. The need for electricity is so universal and so ubiquitous that an increase in electric rates has an economic impact similar to a tax increase. In fact, one could conclude that electric rate increases have a greater impact than tax increases, because taxes are more selective. (Only property owners pay property taxes, and only those who earn a certain amount of income pay income taxes, while almost all people and organizations, including renters, non-profit organizations, and government agencies, buy electricity.)

Electric rate increases manifest in multiple ways throughout a region's economy. Retailers must raise prices; governments must raise taxes or reduce services; businesses may look elsewhere for expansion; some business shift production to other facilities; and some businesses become more likely to close. It is certainly plausible, if not likely, that the

negative impact of SGP rate increases offset or even exceed the secondary economic benefits DP&L estimates. This alone is reason for the PUCO to disregard the favorable economic impact benefits DP&L includes in its cost-benefit analysis and fails the PUCO test for settlement approval.

Q29. WHAT ABOUT GREENHOUSE GAS EMISSION REDUCTION BENEFITS?

A29. First, I believe all the observations I made in the introduction to this topic regarding the inclusion of indirect benefits in a cost-benefit analysis apply to greenhouse gas emission reductions too. But in addition, I note that DP&L assumes a greenhouse-gas emissions cost of as much as [redacted] per ton avoided in its cost-benefit analysis.[19] In its initial application, the maximum cost per ton DP&L assumed was only $15.[20] Such forecasts are simply unreliable; the appropriate cost to use for a ton of greenhouse gas emissions reduction could be zero, it could be [redacted] it could be anywhere in between. Due to either the general reluctance to include indirect benefits I encourage the PUCO to adopt, or to the inherent variability in valuation, I believe the best course of action is to exclude potential greenhouse gas reduction benefits from cost-benefit analysis altogether. After all, as indicated earlier, the Settlement already excludes direct benefits, from time-of use rates to energy conservation, from the cost-benefit analysis. I cannot imagine why a potential indirect benefit like greenhouse gas reductions should be included in a cost-benefit analysis when direct benefits like time-of-use rates and energy conservation are being excluded.

[19] *See* PJA-04. DP&L Stipulation Cost-Benefit Analysis. Tab WP_C Societal Benefits, cell X-30.

[20] *See* PJA-02. DP&L Application Cost-Benefit Analysis. Tab WP_C Societal Benefits, cell X-30.

1 ***C. Concern that DP&L's Reliability Benefit Estimates are Unrealistic***

2

3 ***Q30. IF THE PUCO WERE TO AGREE THAT EV FUEL COST SAVINGS AND THE***
4 ***ECONOMIC IMPACT OF DP&L SPENDING SHOULD NOT COUNT AS***
5 ***CUSTOMER BENEFITS, RELIABILITY IMPROVEMENTS WOULD THEN***
6 ***REPRESENT THE LARGEST SINGLE SOURCE OF ECONOMIC BENEFIT IN***
7 ***DP&L'S COST-BENEFIT ANALYSIS. DO YOU AGREE WITH DP&L'S***
8 ***RELIABILITY IMPROVEMENT BENEFIT ESTIMATES?***

9 ***A30.*** I think they are overstated. All utilities that attempt to quantify the economic benefits
10 associated with reliability improvements use a two-step process. In the first step, the utility
11 attempts to estimate reliability improvements, generally in terms of customer interruption
12 frequency (counts) and duration (minutes), or using associated SAIFI and CAIDI metrics,
13 respectively.[21] In the second step, the utility attempts to translate estimated reliability
14 improvements into economic benefits, using outage cost data published by the U.S.
15 Department of Energy (DOE). Unfortunately, I believe the SAIFI and SAIDI
16 improvements specified in the Settlement are unrealistic, and the DOE outage cost data to
17 be fundamentally flawed, leading to overstated reliability improvement benefits in DP&L's
18 cost-benefit analysis.

[21] SAIFI is an abbreviation of System Average Interruption Frequency Index; SAIDI is an abbreviation of System Average Interruption Duration Index; CAIDI is an abbreviation of Customer Average Interruption Duration Index.

Q31. WHY DO YOU BELIEVE THE SAIFI AND SAIDI IMPROVEMENTS DP&L AGREES TO IN THE SETTLEMENT ARE UNREALISTIC?

A31. The Settlement specifies that DP&L will add distribution automation capabilities to 88, or 20%, of DP&L's circuits.[22] The Settlement also clarifies that the cost-benefit analysis DP&L supplied for the Settlement assumes a 15% improvement in system-wide SAIFI and a 14% improvement in system-wide SAIDI.[23] For DP&L to deliver a 14% improvement in SAIDI system wide, the 20% of circuits with distribution automation would need to deliver five times that amount, or a 70% improvement. In the research I have completed, the distribution automation capabilities DP&L is proposing have been shown to be incapable of delivering improvements of such magnitude.

Q32. WILL SUBSTATION AUTOMATION CONTRIBUTE TO RELIABILITY IMPROVEMENTS?

A32. Yes, but not much. The ability to throw switches remotely will eliminate the 15 minutes it typically takes a lineman to travel to a substation and throw a switch manually. But considering the fact that the SGP will automate less than 1/3 of DP&L's substations, and the fact that outages that can be shortened by throwing switches at a substation represent only a subset of all outages, one can readily perceive that the impact of adding remote-controlled switches to substations will be small. In shorthand, 15 minutes x 1/3 of

[22] Settlement, page 11, section 6.b.

[23] Settlement, page 42, section 17.a.

substations automated x 1/3 of outages shortened using substation switching = 1.6 minutes system wide SAIDI improvement annually.

Q33. DON'T SMART METERS CONTRIBUTE TO RELIABILITY IMPROVEMENTS?

A33. Only minimally, and generally only in storm situations when multiple outages, and nested outages, are common. In such situations, smart meters can help reduce the time restoration crews spend hopping between damage locations. But this benefit is small and limited to storm situations. Ohio reliability standards are based on clear day reliability, meaning that standards are not applicable to major event day (storm) performance.

Q34. YOU MENTIONED THAT THE DOE DATA ON OUTAGE COSTS UTILITIES USE TO TRANSLATE RELIABILITY IMPROVEMENTS INTO ECONOMIC BENEFITS IS FUNDAMENTALLY FLAWED. HOW SO?

A34. The DOE's outage cost data was not collected in an appropriate manner, nor was the data ever intended to estimate the economic impact of outages over a defined geography. Instead, the DOE found some outage cost data a few utilities had collected – in some cases more than 30 years ago -- and tried to make use of it.[24] But the data is inappropriate for use in making grid investment decisions of hundreds of millions of dollars.

[24] Sullivan M, et al. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States.* Lawrence Berkeley National Labs Report LBNL-6941E. Pages 16-17 and 48-49. January,2015.

Q35. CAN YOU BE MORE SPECIFIC?

A35. The first problem is methodological. A handful of utilities have conducted 14 survey projects over the past 30 years to estimate the average cost of outages of various durations to various types of customers. The DOE uses this data in its online tools, which DP&L employed in its reliability benefit calculations. However, the cost of an outage to an individual customer is not the same as the cost of an outage to a defined geography (such as a utility's service territory). It is inappropriate to simply aggregate the outage costs estimated by individual customers to approximate the economic impact of outages across a metropolitan area.

Consider a residential customer, faced with no electricity for cooking and air conditioning, who decides to go out to dinner, or to shopping mall; such an outage would benefit some businesses and the local economy. Consider a motorist in need of gasoline, who bypasses a gas station without power in favor of a gas station with power. In this situation, while one business lost revenue, another business gained revenue, resulting in no net economic loss to the community as a whole. In summary, the data the utilities collected (in one case as far back as 1989) is wholly inappropriate to the uses to which the data is now being employed.

There are also significant problems with the way the surveys were administered, which introduced several types of bias. These biases are particularly prevalent in the Commercial and Industrial (C&I) customer surveys, including the following:

- The surveys were limited in number, conducted decades ago, and collected data only from C&I customers in manufacturing and retail businesses (now a minority among non-residential customer classes),
- The identities of the survey takers – utilities – were known to the C&I customers, which likely biased responses from respondents hoping for financial renumeration,
- The 14 survey projects were completed in just five US geographies, and
- There is no consistency in how survey respondents took back-up generation and uninterruptible power supplies into account when completing surveys.

To summarize, DOE cost per outage data cannot be relied upon to make grid modernization decisions of any magnitude, let alone the $867 million ($1,651 per customer, not including carrying charges) DP&L requested in its initial application.

D. Cost-Benefit Analysis from the Perspective of Customers Overall

Q36. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO THE COSTS AND BENEFITS DP&L ESTIMATES IN ITS SGP COST-BENEFIT ANALYSIS, AS MODIFIED BY THE SETTLEMENT.

A36. Details behind my estimate of the total costs customers will pay (including carrying charges) are presented in Appendix B, and details of the benefit adjustments I recommend are presented in Appendix C. The resulting cost-benefit analysis, reflecting the actual costs customers will pay to the actual benefits customers will receive, is compared to DP&L's

cost-benefit analysis below. In present value terms (future cash flows converted into today's dollars), DP&L claims it will generate $2.50 (rounded up from $2.46) in benefits for every $1 DP&L spends. After making the adjustments to benefits and costs described in this section, I estimate customers will receive just $0.45 in benefits for every $1 customers pay. Note that this poor showing does not reflect adjustments to reduce economic benefits of reliability improvements that DP&L claims. This is because, though I believe those benefits to be inflated, I have no basis on which to recommend alternative reliability benefit calculations.

1

BENEFITS & COSTS ($ in millions)	NOMINAL VALUE	PRESENT VALUE
BENEFITS per DP&L	**1255.3**	**697.3**
OCC Adjustments		
Rate Case Timing	(85.1)	(36.2)
Discountinued Benefit Offset	(146.0)	(60.0)
Exaggerated Benefits	(4.7)	(2.2)
EV Fuel Savings	(229.8)	(83.7)
Economic Impact	(400.1)	(336.8)
GHG Reductions	(41.3)	(13.5)
BENEFITS per OCC	**348.1**	**164.9**
COSTS per DP&L	**387.9**	**284.0**
OCC Adjustments		
Carrrying Charges	180.2	21.8
Missing CIS capital & O&M	96.5	58.9
Cust Pmts on Equip Removed	9.2	6.0
COSTS per OCC	**673.8**	**370.7**

DP&L (Present Value): $2.46 in benefits for every $1 DP&L spends

OCC (Present Value): $0.45 in benefits for every $1 Customers Pay

2

3 ***E. Cost-Benefit Analysis from the Perspective of Residential Customers***

1 ***Q37. YOU MENTIONED EARLIER THAT AN SGP COST-BENEFIT ANALYSIS FOR***
2 ***RESIDENTIAL CUSTOMERS WOULD BE EVEN WORSE THAN THAT FOR***
3 ***CUSTOMERS OVERALL. CAN YOU EXPLAIN THIS?***
4 ***A37.*** According to current cost of service allocations, residential customers pay 66.3% of
5 DP&L's distribution revenue requirement. However, according to DP&L's projections,
6 only 3.8% of the economic benefits from reliability improvements will accrue to residential
7 customers.[25] In addition reliability benefits, estimated to be $193 million over 20 years, are
8 some of the largest in DP&L's cost-benefit analysis. Adjusting the cost-benefit analysis for
9 these factors would undoubtedly make the cost-benefit ratio even worse for residential
10 customers than the ratio for customers overall.
11
12 **III. CUSTOMERS BEAR 100% OF THE RISK OF DP&L'S SGP INVESTMENTS,**
13 **AND STIPULATED PERFORMANCE MEASURES ARE INADEQUATE,**
14 **FAILING TO PROTECT CUSTOMER AND PUBLIC INTERESTS.**
15
16 ***Q38. EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT CUSTOMERS BEAR 100%***
17 ***OF THE RISK ASSOCIATED WITH DP&L'S SGP INVESTMENT.***
18 ***A38.*** The presentation of grid investment plans to regulators for approval in advance is a
19 relatively new phenomenon. Until recently, utilities invested in their grids to the extent
20 required to deliver safe and reliable service. The risk that such investments would be

[25] DP&L Stipulation Cost-Benefit Analysis. Tab WP_B Customer Benefits. Cells Y174+Y185 divided by Y171.

disallowed as imprudent was extremely low. As electric distribution grids in the United States already distribute electricity safely and reliably, grid modernization investments are not technically required. Utilities have responded by offering favorable cost-benefit analyses to justify their grid modernization plans, seeking advance approval. Once approved, any disallowance risks a utility may have had is essentially eliminated. What regulator, having approved a utility's application to invest hundreds of millions of dollars in its grid in the name of modernization, would disallow those investments later? Furthermore, what regulator would expose customers to the cost of capital increases that would invariably follow a decision to disallow recovery of such massive investments? Once a grid modernization plan is approved, utility risk falls to zero (unless a regulator assigns economic consequences for failure to deliver projected benefits, which I recommend to more equitably balance risk between shareholders and customers).

Lacking disallowance risk or performance consequences, as the Settlement in this case does, customers must rely entirely on performance measurement to "guilt" utilities into delivering project grid modernization plan benefits. Given the performance variability I have observed, benefits in excess of costs cannot be assured without performance measurement. In this case, the Settlement's performance measures are inadequate, and no consequences for failure to deliver anticipated benefits are specified (see next). To summarize, DP&L customers will pay for the SGP, plus profits, no matter what, while the customers rely completely and blindly on DP&L for any benefits to offset rate increases. This is what I mean when I say customers bear 100% of performance risk. I note that this

is not what the PUCO had anticipated from Ohio utilities' grid modernization plans. Indeed, the PUCO's own Power Forward investigation concluded that the utilities "will have to bear some risk for their failure to either hit performance benchmarks or contain costs."[26]

Q39. BUT IN THIS CASE, THE SETTLEMENT SPECIFIES SAIFI AND SAIDI IMPROVEMENTS, AS WELL AS A HOST OF PERFORMANCE METRICS.

A39. In this section of testimony, I will explain why the Settlement's performance specifications are inadequate to protect consumers. Given 1) that customers will bear 100% of the performance risk if the PUCO approves the Settlement; and 2) the inherent variability in grid modernization benefit delivery, I recommend the PUCO reject the Settlement. Settlement accountability is inadequate because:

1. The structure of reliability improvements specified in the Settlement is inconsistent with current Ohio reliability standard structure, resulting in zero accountability for reducing system average interruption duration;
2. The Settlement's performance metrics will not ensure benefits, and are no substitute for a post-deployment benefit evaluation the Settlement fails to require;
3. The Settlement reduces the benefits DP&L will deliver to customers by failing to consider the benefits from several foundational smart meter capabilities.

[26] Public Utilities Commission of Ohio. "Power Forward: A Roadmap to Ohio's Energy Future." Page 27.

A. The Settlement Provides No Accountability for Reducing Interruption Duration

Q40. WHAT RELIABILITY COMMITMENTS DOES DP&L MAKE IN THE SETTLEMENT?

A40. The Settlement states "No later than 60 months following an Order in this case, DP&L shall file an application for revised standards that incorporate the proposed reliability improvement."[27]

Q41. WHAT IS "THE PROPOSED RELIABILITY IMPROVEMENT"?

A41. The proposed reliability improvements include a 15% improvement in system-wide average interruption frequency (SAIFI) and a 14% improvement in system-wide average interruption duration (SAIDI).[28]

Q42. WHY ARE THESE STIPULATED PERFORMANCE MEASURES INADEQUATE?

A42. These measures are inadequate because the structure is inconsistent with the current Ohio rules related to system-wide reliability standards,[29] which specify SAIFI and CAIDI, not SAIFI and SAIDI.[30] Because the current Ohio reliability standard does not include

[27] Settlement, page 42, section 17.a.

[28] Ibid.

[29] Ohio Adm. Code 4901:1-10-10(B)(1).

[30] SAIFI, SAIDI, and CAIDI are related. CAIDI is the average duration of an interruption, but only of customers who experienced at least one. CAIDI is calculated by dividing SAIDI by SAIFI.

SAIDI,[31] DP&L could conceivably meet its new CAIDI standard, based on the Settlement's reliability commitments, without improving grid modernization's most critical statistic – system average interruption duration – at all.

Q43. CAN YOU PROVIDE AN EXAMPLE?

A43. Assume DP&L's current SAIDI is 100 minutes, meaning that a 14% improvement would amount to 86 minutes. Assume DP&L's current SAIFI is 1.0 interruptions per year, meaning that a 15% improvement would amount to 0.85 interruptions per year. Note that under either calculation, customer average interruption duration – the Ohio standard metric – remains essentially unchanged, and actually becomes slightly easier to achieve:

	SAIDI (a)	SAIFI (b)	CAIDI (Ohio Standard; a ÷ b)
Existing	100	1.0	100
Target per Settlement	86	0.85	101

The Settlement fails to hold DP&L accountable for any improvement in its Ohio CAIDI standard even after spending nearly $270 million, not including $54 million in information technology spending, nor the carrying charges that customers will pay.

[31] I understand that one aspect of the Ohio reliability reporting related to poor performing feeders, does use SAIDI. But the system-wide reliability standard relevant to performance in the Settlement specifies do not include SAIDI.

Q44. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE SETTLEMENT'S RELIABILITY REQUIREMENTS?

A44. I note that the new reliability metrics, though largely ineffective as structured, will not be updated for more than five years after the Settlement is approved. It seems to me a more appropriate measurement approach would be to hold DP&L responsible for incremental improvements over time, coincident with distribution automation and smart meter roll-out timing. For example, if distribution automation is 30% deployed by the end of year two, then 30% of the ultimate reliability improvement expected should be in force for year three.

B. The Settlement's performance metrics will not ensure benefits and are no substitute for a post-deployment benefit evaluation.

Q45. WHY DO YOU BELIEVE THE ONLY WAY TO ADEQUATELY ENSURE CONSUMERS ACHIEVE THE PERFORMANCE METRICS UNDER THE SETTLEMENT WILL BE THROUGH A POST-DEPLOYMENT BENEFIT EVALUATION?

A45. In the future, the only way to safeguard that the benefits DP&L claims it will deliver from its SGP were actually delivered to consumers is to measure them directly, via a post-deployment benefit evaluation audit. The metrics specified in the Settlement fall far short of this goal, which customer interest and the public interest demand. The PUCO has already recognized the need for such audits in its Power Forward investigation, saying such audits should 1) evaluate whether the capital deployed resulted in grid functionality that is in

accordance with the company's grid modernization plan; 2) evaluate whether (performance-based ratemaking) metrics are being achieved; and 3) include a prudency review. Further, the PUCO states "The results of these audits could impact recovery by the (utilities)."[32] I note that none of these concepts feature in the Settlement's audit provisions, which focus on accounting issues, not performance issues. There should be financial repercussions to DP&L if customers do not get the benefits touted in the SGP.

Q46. IN WHAT WAYS ARE THE SETTLEMENT'S PERFORMANCE METRICS DEFICIENT?

A46. The Settlement specifies 42 metrics for measuring DP&L performance. While this sounds impressive, just seven of the metrics are *outcome* metrics. Outcome metrics measure a result from which a customer would actually benefit. The other 35 metrics are *process* metrics, meaning that they measure deployment status, or some indicator of potential benefit, without measuring an outcome relevant to customers (such as a headcount reduction). Process metrics do not measure a direct benefit delivered to customers from the SGP.

Q47. CAN YOU PROVIDE EXAMPLES TO HELP ILLUSTRATE THE DIFFERENCE?

A47. The seven-outcome metrics are 1) Count of internal meter readers, 2) Count of contract meter readers, 3) AMI meter tampering case outcomes, 4) Customer minutes saved, 5)

[32] Power Forward final report, page 27.

Customer interruptions avoided, 6) MW Saved from CVR, and 7) MWh Saved from CVR. By contrast, the table below lists a sample of process metrics, and describes the associated shortcoming of each:

Metric	Accountability Issue
Count of call center calls (meter reading, high bill)	Did any headcount reductions result? (DP&L's estimates $13.5 million in call center cost reductions over 20 years)
Count of Non-payment Disconnects (AMI)	Did any headcount reductions result? (DP&L estimates $27.2 million in meter services cost reductions over 20 years)
Count of Outage-related truck rolls (avoided)	Did any headcount reductions result? (DP&L estimates $2.4 million in field crew cost reductions over 20 years)

Q48. ARE THERE OTHER SHORTCOMINGS IN THE METRICS?

A48. Yes. I note that none of the metrics include quantified targets. I don't know how DP&L's performance can be evaluated as good, fair, or poor, without targets. Further, some significant benefits aren't even covered by a process measure, let alone an outcome measure. For example, DP&L says it will use its new GIS system to identify, and commence billings on, previously unidentified pole attachments. DP&L estimates it will increase pole attachment billings by [redacted] over 20 years. Yet the Settlement includes no metrics at all for this benefit.

C. The Settlement reduces the benefits DP&L will deliver to customers by failing to consider the benefits from several foundational smart meter capabilities

Q49. HOW WILL THE SETTLEMENT REDUCE THE SGP BENEFITS DP&L DELIVERS TO CUSTOMERS?

A49. DP&L's original cost-benefit analysis included $54.3 million in capital[33] for a new Customer Information System (CIS). Some of the largest potential customer benefits from smart meters, including time-varying rates and energy conservation support (via online portals, detailed usage data access, high bill alerts, and similar capabilities and features), cannot be enabled without the new CIS. In the cost-benefit analysis provided with the Settlement, the CIS investment was eliminated,[34] along with associated benefits. As I described earlier, the removal of CIS investments from the cost-benefit analysis understates SGP costs. But an even larger issue is that by eliminating the time-varying rate and energy conservation benefits, DP&L responsibility for securing these potential benefits was also eliminated.

Q50. BUT DOESN'T THE SETTLEMENT ADDRESSES THESE CAPABILITIES?

A50. Yes and no. In its initial application DP&L estimated it would deliver [redacted] in demand reduction and energy conservation benefits over 20 years from time-varying rates and its customer portal.[35] In contrast, the Settlement specifies that DP&L will offer a time-of-use rate as a pilot,[36] and will implement a customer portal.[37] In my mind, the difference

[33] *See* PJA-02.

[34] *See* PJA-04. DP&L Stipulation Cost-Benefit Analysis. Tab "Cost-Benefit Detailed Summary". Lines 10 and 11.

[35] *See* PJA-04. DP&L Application Cost-Benefit Analysis. Tab "WP_B Customer Benefits". Line Nos. 33-45.

[36] Settlement, page 11, Section 6.e.

[37] Settlement, page 21, Section 10.b.

is monumental, and similar to the outcome metric/process metric difference I described earlier. A Settlement that specifies [redacted] in demand reduction and energy conservation benefits is in the interest of customers and the public; a Settlement that removes DP&L accountability for securing specific economic benefits from some of the most foundational capabilities smart meters have to offer is not in the interest of customers or the public.

I note that demand reduction reduces DP&L's need to spend capital to increase grid capacity, and that energy conservation reduces DP&L revenues (and profits) between rate cases. Because of these economic disincentives, I have found that demand reduction and energy conservation benefits from smart meters, though among the greatest of all potential smart meter benefits, are the most difficult to secure post-deployment. I have observed utilities mitigate the economic exposure of these capabilities, simultaneously reducing customer benefits, in a variety of ways. Some are subtle, and some are not so subtle:

- By failing to promote time-of-use rates;
- By designing time-of-use time periods in ways customers find difficult to manage;
- By failing to promote customer portals and third-party data access features;
- By failing to offer high bill alert programs to customers;
- By making portal registration difficult, or certain features challenging to access;
- By charging fees to customers and/or third parties for data access participation.

Q51. SO, TO SUMMARIZE, THE SETTLEMENT DOES NOT BENEFIT CUSTOMERS AND THE PUBLIC INTEREST DUE TO THE LACK OF PERFORMANCE CONSEQUENCES AND PERFORMANCE MEASURES?

A51. Correct. Or as I like to put it, customers assume all risk. Not only does the Settlement include no consequences for a failure to deliver benefits in excess of cost – the very basis by which DP&L justifies its SGP investment – inadequate performance measurement makes certain that the PUCO would not even be aware of such an outcome. Add to these egregious Settlement deficiencies the fact some of the most significant smart meter benefits available aren't even quantified in the Settlement's cost-benefit analysis, it becomes clear that Settlement is not in the public interest. Even if a favorable cost-benefit analysis for customers were a given, though the first section of my testimony indicates this is clearly not the case, I believe the lack of performance consequences and performance measures alone should be enough to reject the Settlement as it stands. But there is yet another significant rationale for the PUCO to reject the Settlement: it enables DP&L to make Phase 2 investments without validating that Phase 1 was a success.

IV. THE SETTLEMENT ALLOWS FOR PHASE 2 INVESTMENTS BEFORE THE SUCCESS OF PHASE 1 CAN BE DETERMINED.

Q52. YOUR RECOMMENDATION THAT THE SETTLEMENT BE REJECTED IS BASED ON YOUR ASSESSMENT THAT CUSTOMER BENEFITS WILL NOT EXCEED COSTS, AND THAT CUSTOMERS BEAR ALL SGP INVESTMENT RISK DUE TO A LACK OF PERFORMANCE CONSEQUENCES AND INADEQUATE PERFORMANCE MEASUREMENT. HOW DOES AN SGP PHASE 2 COMPOUND THESE PROBLEMS FOR CUSTOMERS?

A52. The Settlement specifically permits DP&L to propose a Phase 2 SGP within three years of the PUCO's decision in this case.[38] If the Settlement is approved as it stands, DP&L will not have even finished its Phase 1 deployment, let alone demonstrated the full results of the limited outcome and process metrics specified in the Settlement. As demonstrated in this testimony, the SGP is unlikely to deliver customer benefits in excess of customer costs, nor are the performance measures specified in the Settlement adequate to gauge the DP&L's success with Phase 1. That DP&L might receive approval to invest hundreds of millions of dollars more in grid assets not required for safe and reliable service in such circumstances is clearly not in customers' interests. If the PUCO approves this Settlement, it is signaling that any grid investment is prudent grid investment, with no evidence to back such an assessment. This is inconsistent with the PUCO's own Power Forward

[38] Settlement, page 5.

1 investigation, which states " . . . the Commission's expression of governmental will to
2 allow the (utilities) to invest in grid modernization for the betterment of customers is not a
3 blank check. Performance will be evaluated and tied in some circumstances to recovery . .
4 . ."[39]
5
6 ***Q53. BUT THE PUCO HAS SPONSORED TWO SMART GRID BENEFIT***
7 ***EVALUATIONS, INCLUDING AN EVALUATION OF* AEP's *gridSMART***
8 ***BENEFITS, AND THE EVALUATION YOU LED ON DUKE ENERGY'S OHIO***
9 ***DEPLOYMENT BENEFITS. AREN'T THOSE EVALUATIONS SUFFICIENT***
10 ***EVIDENCE?***
11 ***A53.*** No. When it comes to grid modernization, I have significant concerns regarding any
12 assumption that the benefit evaluations completed in Ohio to date are sufficient to preclude
13 a similar evaluation for DP&L, and any associated assumption that Phase 2 of DP&L's
14 SGP should proceed before the results of Phase 1 are measured. These include:
15
16 - The PUCO has yet to conduct a post-deployment benefit evaluation;
17 - At least one of the mid-term benefit evaluations the PUCO has reviewed does not
18 indicate that grid modernization benefits clearly exceed costs to customers; and
19 - Each grid modernization plan and utility are unique, and DP&L's ability to secure
20 SGP benefits has not been demonstrated.

[39] Power Forward final report, page 27.

Q54. LET'S BEGIN WITH THE NOTION THAT THE GRID MODERNIZATION BENEFIT EVALUATIONS THE PUCO HAS ALREADY SPONSORED WERE INSUFFICIENT. WHAT SUPPORT DO YOU OFFER FOR THIS CLAIM?

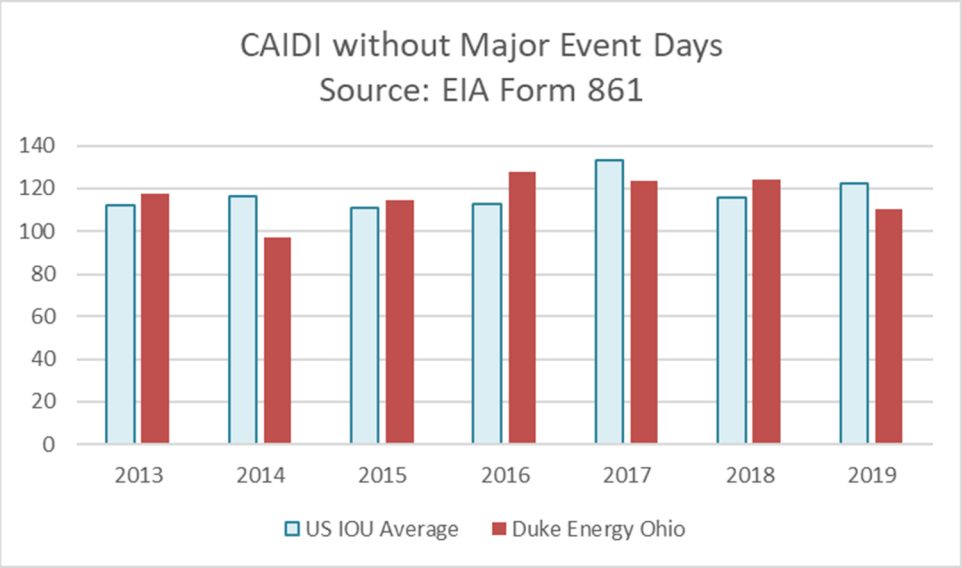
A54. Both the AEP gridSMART and Duke Energy Ohio deployment evaluations were mid-term evaluations, meaning that the evaluations were conducted before the deployments were complete. Based on first-hand experience, I know that many assumptions and extrapolations are required when attempting to estimate full benefits based solely on partial and early results. There is no doubt in my mind that post-deployment evaluations are more accurate and thorough than mid-term evaluations. But the reality is that the PUCO has yet to review a post-deployment grid modernization benefit evaluation.

Q55. BUT THE MID-TERM REVIEWS DEMONSTRATED THAT GRID MODERNIZATION BENEFITS CLEARLY EXCEED COSTS, ISN'T THAT RIGHT?

A55. That is not my impression. For example, the evaluation my team completed estimated the benefits from Duke Energy Ohio's deployment were likely to be between $325 and $447 million (present value).[40] While the cost of Duke Energy's Ohio deployment is not publicly available, information that is publicly available is enlightening. Duke Energy received a $200 million matching grant from the US Department of Energy as part of the 2009 American Reinvestment and Recovery Act, meaning that Duke Energy's Ohio deployment

[40] Duke Energy Mid-Term Review. Page 73.

would have cost at least $400 million without the grant. Given that the $400 million minimum cost estimate does not include carrying charges customers are still paying, my perception is that the cost-effectiveness of grid modernization is anything but clear. Further, a review of recent Duke Energy Ohio reliability performance reveals that it is no better than the average US investor-owned utility, nor does it show any reliability performance improvement over time, as a result of grid modernization investments.



For me, the bottom line is that grid modernization investments are not the "no brainer" many believe them to be. A follow-on conclusion is any Settlement that allows DP&L to invest more into grid modernization without first determining that SGP Phase 1 delivered benefits in excess of costs cannot possibly be in the customer or public interest.

Q56. YOU OBSERVED THAT EVERY GRID MODERNIZATION PLAN AND EVERY UTILITY IS UNIQUE. WHAT IS THE RELEVANCE OF THIS TO THE SETTLEMENT'S ALLOWANCE OF A PHASE 2 PLAN BEFORE PHASE 1 RESULTS ARE KNOWN?

A56. My observation is simply additional support for the need for a post-deployment benefit evaluation of every grid modernization plan, given that benefits delivered vary widely by utility. Even if both the AEP and the Duke Energy evaluations clearly demonstrated that those grid modernization plans delivered benefits to customers in excess of costs, the PUCO should not assume that DP&L will also deliver benefits in excess of costs from its SGP. The fact remains that DP&L will not yet have demonstrated success at delivering benefits from its SGP by the time it might be allowed to increase investments in SGP Phase 2.

Q57. ARE THERE OTHER REASONS WHY DP&L SHOULD NOT BE ALLOWED TO FILE A PHASE 2 APPLICATION UNTIL SGP PHASE 1 HAS BEEN EVALUATED?

A57. Yes. In addition to the obvious benefit of measuring actual reliability and economic benefits from SGP capabilities, there are a great deal of things the PUCO and stakeholders could learn from a completed Phase 1. Examples include:

- How did DP&L select circuits for distribution automation and conservation voltage reduction? Could the benefit-to-cost ratio for these capabilities be improved by limiting deployments to circuits with certain characteristics?
- How many voltage violations were created by DP&L's conservation voltage system? Is DP&L being too conservative with the capability? How much more conservation and demand response should the PUCO require from the capability, if any?
- How aggressively is DP&L promoting its TOU rate option? What alternatives to increasing TOU benefits, like universal peak-time rebate, should be considered?
- Did DP&L launch a high bill alert program? How aggressively is DP&L promoting this feature?
- To what extent has customer safety been compromised through the waiver of the door knock requirement? How many complaints about new processes have been received?

V. SUMMARY AND RECOMMENDATIONS

Q58. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE SETTLEMENT.

A58. My recommendation is that the PUCO reject the Settlement because it fails to comply with the second requirement used by the PUCO to evaluate settlements. The second prong of the three-part test requires a demonstration that the Settlement benefits customers and the

public interest. My belief that the Settlement is not in the interest of customers or the public is supported by three arguments:

- DP&L's SGP, as proposed and revised in the Settlement, will not deliver benefits in excess of costs to customers, and is particularly harmful to residential customers. I estimate that customers will receive about $0.45 in benefits for every $1 paid to DP&L for the SGP, and that residential customers will receive even fewer benefits per dollar spent.
- Customers bear 100% of the risk of DP&L's SGP investments, and stipulated performance measures are inadequate, violating customer and public interests.
- The Settlement allows for Phase 2 investments before the success of Phase 1 can be determined.

Q59. HOW CAN THE PUCO IMPROVE THE RESULTS OF GRID MODERNIZATION SPENDING?

A59. I offer several recommendations including:

- Allocate grid modernization costs among customer classes in relation to benefits delivered. As the economic benefits of reliability improvements are among the largest of those potentially available from grid modernization, and as these skew dramatically to commercial & industrial ("C&I") customers, C&I customers should bear a greater burden for grid modernization cost recovery relative to routine cost recovery. While the Settlement specifies current cost allocations by class -- 33%

for C&I – DP&L expects C&I customers to secure 96% of the economic benefits from reliability improvements.

- Establish guidelines for grid modernization cost-benefit analyses. These guidelines should specify the inclusion of carrying charges; the treatment of stranded costs; the types of capabilities and benefits the PUCO expects to see; how to value reliability improvements; and the types of benefits the PUCO will not consider, such as indirect/societal benefits (unless accompanied by indirect/societal costs).
- Conduct "willingness to pay" research among various customer classes. Understand what customers would be willing to pay for various levels of reliability improvement, and take this into account when evaluating utility grid modernization or reliability improvement plans.
- Sponsor an independent research project intended to estimate the economic impact of service interruptions of various durations to communities. Require utilities to use these research results in any attempts to quantify the economic benefits of reliability improvements as part of cost-benefit analyses.
- Address the rate case timing issue. Make certain that grid modernization plans include estimates for the year by which all benefits will be reflected in a utility's books and records and specify the timing for a rate case using that year as a test year. This will benefit customers by synchronizing the Utility's request to increase distribution costs for the smart grid to customers at the same time the benefits of the smart grid are available for comparison. The PUCO should not approve distribution costs in excess of the benefits of the smart grid.

- Make certain that grid modernization investment risk is shared between utilities and customers. Establish utility consequences for failure to deliver the level of benefits projected as called for in the PUCO's own Power Forward Roadmap final report.
- Measure benefits in a post-deployment benefit evaluation as called for in the PUCO's own Power Forward Roadmap final report.
- Prevent a utility from making additional grid modernization investments until the customer benefits from investments it has already made (and customers have been charged for) have been measured and shown to be in excess of costs to customers.
- Ensure reliability improvement metrics employ the same structure specified in Ohio standards, currently system average interruption frequency index (SAIFI) and customer average interruption frequency index (CAIDI). Inconsistencies in the Settlement fail to hold DP&L accountable for interruption duration improvement.

Q60. DOES THIS CONCLUDE YOUR TESTIMONY?

A60. Yes, it does. However, I reserve the right to incorporate new information that may subsequently become available through outstanding discovery or otherwise.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Paul J. Alvarez on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission to the persons listed below on this 17th day of December 2020.

/s/ Angela D. O'Brien
Angela D. O'Brien
Assistant Consumers' Counsel

The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

SERVICE LIST

Case No. 18-1875-EL-GRD, et al.

steven.beeler@ohioattorneygeneral.gov
Robert.eubanks@ohioattorneygeneral.gov
Bethany.allen@igs.com
Joe.oliker@igs.com
Michael.nugent@igs.com
dstinson@bricker.com
khernstein@bricker.com
jspottswood@bricker.com
jdunnlegal@gmail.com
kevin.oles@thompsonhine.com
stephanie.chmiel@thompsonhine.com
cmooney@opae.org
whitt@whitt-sturtevant.com
glover@whitt-sturtevant.com
drinebolt@opae.org
nvijaykar@elpc.org
glpetrucci@vorys.com
dparram@bricker.com
dstinson@bricker.com
ccox@elpc.org
Michael.schuler@aes.com
jsharkey@ficlaw.com
djireland@ficlaw.com
chollon@ficlaw.com
fdarr@mwncmh.com
mpritchard@mwncmh.com
mfleisher@dickinsonwright.com
cpirik@dickinsonwright.com
mkurtz@bkllawfirm.com
kboehm@bklawfirm.com
jkylercohn@bkllawfirm.com
Bojko@carpenterlipps.com
Dressel@carpenterlipps.com
Paul@carpenterlipps.com
Dutton@carpenterlipps.com
slesser@beneschlaw.com
talexander@beneschlaw.com
mkeaney@beneschlaw.com

Attorney Examiners:
Patricia.schabo@puco.ohio.gov
gregory.price@puco.ohio.gov

Case No. 19-1121-EL-UNC

steven.beeler@ohioattorneygeneral.gov
Michael.schuler@aes.com
mkurtz@bkllawfirm.com
kboehm@bkllawfirm.com
talexander@beneschlaw.com
jkylercohn@bkllawfirm.com
bojko@carpenterlipps.com
paul@carpenterlipps.com
mpritchard@mcneeslaw.com
rglover@mcneeslaw.com

Attorney Examiners:
Patricia.schabo@puco.ohio.gov
gregory.price@puco.ohio.gov

Case No. 20-1041-EL-UNC

steven.beeler@ohioattorneygeneral.gov
Michael.schuler@aes.com
Bojko@carpenterlipps.com
Paul@carpenterlipps.com
mpritchard@mcneeslaw.com
rglover@mcneeslaw.com
talexander@beneschlaw.com

Attorney Examiners:
Patricia.schabo@puco.ohio.gov
Michael.williams@puco.ohio.gov

Case No. 20-680-EL-UNC

thomas.lindgren@ohioattorneygeneral.gov
dparram@bricker.com
dstinson@bricker.com
jspottswood@bricker.com
bojko@carpenterlipps.com
Bethany.allen@igs.com
Joe.oliker@igs.com
Michael.nugent@igs.com
Fdarr2019@gmail.com
paul@carptenterlipps.com
kevin.oles@thompsonhine.com
stephanie.chmiel@thompsonhine.com
jsharkey@ficlaw.com
djireland@ficlaw.com
chollon@ficlaw.com
michael.schuler@aes.com
mkurtz@bkllawfirm.com
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com
mpritchard@mcneeslaw.com
rglover@mcneeslaw.com
slesser@beneschlaw.com
talexander@beneschlaw.com
mkeaney@beneschlaw.com
khehmeyer@beneschlaw.com

Attorney Examiners:
Patricia.schabo@puco.ohio.gov
Michael.williams@puco.ohio.gov

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Appearances and Research Projects in Regulatory Proceedings

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. August 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on cost-benefit analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Office of Consumer Counsel -- Costs to Customers

OCC Exhibit _____

Dollars in millions

PUC 18-1875-EL-GRD

Discount Rate used to calculate Present Value: 7.27%

Direct Testimony of Paul J. Alvarez dated 12-14-2020

Appendix B

	Description	Present Value	Nominal	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Costs per DP&L																							
	Capital + AFUDC	209.5	249.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost of Existing Equipment	15.0	18.3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	O&M Spending	59.5	120.7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
To	Totals	284.0	387.9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost Adjustments Per OCC																							
	Missing Carrying Charges (See detail below)	21.8	180.2																				
	Missing CIS Replacement Costs	58.9	96.5	9.2	6 2	6.7	7.3	7.3	7.3	7.4	7.4	7.4	7.5	2.1	2.1	2.2	2 2	2.3	2.3	2.4	2.4	2.4	2 5
	RR on equipment removed, but not written off via IIR (yr	3.0	4.6					0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2				
	RR on equipment removed, but not written off via IIR (yr	3.0	4.6						0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2			
To	OCC Total Cost Adjustments	86.8	285.8	110.4	182.8	180 9	127.9	20.9	21.7	19.3	19 5	19.8	20.1	14.9	15.2	15.4	15.7	16.0	16.1	16.0	16.1	16.4	16.7
Costs per OCC		370.8	673.8																				
Missing Carrying Charges:																							
	Revenue Requirement over 20 years (OCC Estimate)	305.8	568.2	7.5	18.4	33.6	48.7	45.5	44.3	38.6	35 9	33.5	26.8	26.7	26.6	26.1	24.7	23.8	23.1	22.5	22.0	21.5	18 5
	Costs per DP&L	284.0	387.9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Missing Carrying Charges:	21.8	180.2																				

Office of Consumer Counsel Adjustments to DP&L's Projected Benefits

OCC Exhibit _____

Dollars in millions

PUC 18-1875-EL-GRD et al

Discount rate for Present Value: 7.27%

Direct Testimony of Paul J. Alvarez Dated 12-14-2020

Appendix C

	Present Value	Nominal Value	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	YR 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20
Benefits per DP&L																						
Utility		207.7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer		606.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Societal		441.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Benefits per DP&L	697.3	1255.3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Benefit Adjustments per OCC																						
Rate Case Timing	-36.2	-85.1	0.0	0.0	0.0	0.0	-4.5	-4.6	-4.7	-4.8	-4.9	-5.0	-5.1	-5.2	-5.4	-5.5	-5.6	-5.7	-5.8	-5.9	-6.1	-6.2
Discontinued Benefit Offset	-60.0	-146.0	0.0	0.0	0.0	0.0	-6.6	-6.7	-6.9	-7.2	-7.6	-8.0	-8.4	-8.8	-9.3	-9.7	-10.0	-10.3	-10.8	-11.3	-11.9	-12.5
Exaggerated Benefits	-2.2	-4.7	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
EV Fuel Savings	-83.7	-229.8	0.0	-0.2	-0.6	-1.4	-2.6	-4.0	-5.2	-6.3	-7.3	-8.6	-10.0	-11.8	-13.7	-16.2	-18.8	-21.1	-23.1	-25.0	-26.5	-27.3
Economic Impact	-336.8	-400.1	-75.7	-127.2	-122.2	-75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GHG Reductions	-13.5	-41.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.4	-0.7	-1.1	-1.5	-2.0	-2.5	-3.0	-3.5	-4.1	-4.7	-5.3	-5.9	-6.6
Total OCC Benefit Adj's	-532.4	-907.2	-75.7	-127.6	-123.0	-76.6	-13.9	-15.6	-17.1	-18.9	-20.8	-23.0	-25.4	-28.1	-31.1	-34.5	-38.2	-41.5	-44.7	-47.8	-50.7	-52.9
Benefits per OCC	164.9	348.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

RPD-1-8. Referring to the Exhibit 2, Distribution Modernization Plan, IIR Revenue Requirement Estimate attached to the Stipulation and Recommendation.

a) Provide this worksheet, and all supporting worksheets, in Excel format with no pasted values, all formulae intact and available for review, and all assumptions and data sources cited.

b) Provide a worksheet which estimates the revenue requirement over the entire 20-year period of the Cost-Benefit Summary provided in Exhibit 4.

RESPONSE: General Objections Nos. 3 (privileged and work product), 4 (proprietary), 9 (vague and undefined). Subject to all general objections, DP&L states please see OCC Set 1 – RPD-1-8 – Attachment 1, DP&L_GRD_0000989.

RPD-1-9. Referring to the Exhibit 4, DP&L SGP Cost Benefit Summary that is attached to the Stipulation and Recommendation.

a) Provide a worksheet and which indicates nominal values for each line item in Figures 1 and 2 by year throughout the 20-year Cost Benefit period. The worksheet should be in Excel format with no pasted values, all formulae intact and available for review, and all assumptions and data sources cited.

b) For each benefit detailed in response to (a), provide the details of benefit estimate calculations. Provide these benefit estimate calculations in Excel format with no pasted values, all formulae intact and available for review, and all assumptions and data sources cited.

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Revenue Requirement Estimate

OCC Set 1 RPD-8 Attachment 1

Exhibit 2

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Source
(A)	(B)	(C)	(D)	(E)	(F)	(M)
	Rate Base					
1	Gross Plant	$ 15,522,814	$ 59,220,824	$ 168,018,441	$ 215,146,166	DP&L Estimate
2	Accumulated Depreciation on Distribution Plant	$ (532,947)	$ (3,271,331)	$ (13,560,288)	$ (31,015,738)	DP&L Estimate
3	Net Distribution Plant In Service	$ 14,989,866	$ 55,949,493	$ 154,458,153	$ 184,130,428	Line 1 + Line 2
4						
5	Adjustments to Rate Base					
6	Accumulated Deferred Income Taxes on Distribution Plant	$ (412,299)	$ (2,563,850)	$ (6,767,993)	$ (12,524,747)	DP&L Estimate
7	NBV of the Cost of Existing Assets	$ (942,507)	$ (6,911,715)	$ (12,880,924)	$ (18,301,689)	DP&L Estimate
8	Total Adjustments to Rate Base	$ (1,354,805)	$ (9,475,565)	$ (19,648,917)	$ (30,826,436)	Line 6 + Line 7
9						
10	Distribution Rate Base for DMP	$ 13,635,061	$ 46,473,928	$ 134,809,236	$ 153,303,992	Line 3 + Line 8
11						
12	Return on Rate Base (%)	8.58%	8.58%	8.58%	8.58%	Pg 4 Line 10
13	Return on Rate Base ($)	$ 1,169,888	$ 3,987,463	$ 11,566,632	$ 13,153,483	Line 10 * Line 12
14						
15	O&M, Depreciation, Taxes Other than Income and O&M					
16	O&M Expense	$ 2,630,081	$ 3,673,826	$ 4,662,505	$ 7,619,523	DP&L Estimate
17	O&M Savings	$ (101,882)	$ (726,683)	$ (2,439,735)	$ (4,385,455)	DP&L Estimate
18	Cost of Existing Assets (Less Salvage)	$ 942,507	$ 5,969,209	$ 5,969,209	$ 5,420,765	DP&L Estimate
19	Depreciation Expense	$ 480,549	$ 2,633,587	$ 9,520,446	$ 16,023,224	DP&L Estimate
20	Property Tax Expense	$ (104,555)	$ 163,092	$ 1,545,746	$ 7,952,685	DP&L Estimate
21						
22	Total O&M, Depreciation, Other Taxes and O&M Before CAT	$ 3,846,700	$ 11,713,030	$ 19,258,170	$ 32,630,742	Sum Lines 16-20
23	Incremental Commercial Activities Tax	1.002607	1.002607	1.002607	1.002607	
24						
25	O&M, Depreciation, Taxes Other than Income and O&M (Post Tax)	$ 3,856,727	$ 11,743,564	$ 19,308,372	$ 32,715,804	Line 22 * Line 23
26						
27	Grid Modernization R&D Asset	$ 2,500,000	$ 2,700,000	$ 2,700,000	$ 2,800,000	Pg 3 Line 15
28						
29	**Revenue Requirement**	$ 7,526,615	$ 18,431,027	$ 33,575,004	$ 48,669,287	Sum Lines 13, 25, 27
30						
31	Rate Design					
32	Annual Base Distribution Revenue Requirement	$ 242,807,679				Order Case No. 15-1830-EL-AIR
33						
34	Distribution Modernization Percentage of Base Distribution Revenue Requirement	**3.1000%**	**7.5910%**	**13.8280%**	**20.0440%**	Line 29 / Line 32

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Advanced Meter Infrastructure (AMI) O&M

OCC Set 1 RPD-8 Attachment 1

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-1.1
Page 2 of 2
Witness Responsible: Kathryn Storm

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Summary of AMI O&M Costs**													
2	Annual Software Maintenance Fee of AMI Head-End	921	$0	$97,997	$100,035	$102,116	$104,240	$106,408	$108,621	$110,881	$113,187	$115,541	$959,026	DP&L Estimate
3	Annual Infrastructure O&M Costs	592 & 597	$134,589	$137,388	$140,246	$143,163	$146,141	$149,181	$152,284	$155,451	$158,685	$161,985	$1,479,114	DP&L Estimate
4	Total Equipment Maintenance		$134,589	$235,385	$240,281	$245,279	$250,381	$255,589	$260,905	$266,332	$271,872	$277,527	$2,438,140	Line 2 + Line 3
5														
6	Increased Call Center Costs	903												
7	Additional calls due to AMI/Smart Meters	903	4,550	28,815	28,815	26,167	24,776	24,776	0	0	0	0		DP&L Estimate
8	Cost per call		$5.00	$5.10	$5.21	$5.32	$5.43	$5.54	$5.66	$5.78	$5.90	$6.02		Company Records
9	Total additional Call Center Costs		$22,748	$147,071	$150,130	$139,172	$134,515	$137,313	$0	$0	$0	$0	$730,949	Line 7 * Line 8
10														
11	Total AMI O&M		$157,337	$382,456	$390,411	$384,451	$384,896	$392,902	$260,905	$266,332	$271,872	$277,527	$3,169,088	Line 4 + Line 9

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Advanced Meter Infrastructure (AMI) Capital

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-1.1
Page 1 of 2
Witness Responsible: Kathryn Storm

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Summary of AMI Investment**													
2	Residential AMI Meters		0	23,176	110,084	110,084	110,084	110,084	0	0	0	0	463,511	DP&L Estimate
3	C&I AMI Meters		0	2,052	9,749	9,749	9,749	9,749	0	0	0	0	41,047	DP&L Estimate
4	Polyphase C&I AMI Meters		0	836	3,970	3,970	3,970	3,970	0	0	0	0	16,717	DP&L Estimate
5	Other C&I Meters		0	17	79	79	79	79	0	0	0	0	334	DP&L Estimate
6	Cost per Residential AMI Meter (Hardware)		$0	$82	$82	$82	$82	$82	$0	$0	$0	$0		Estimate based on Vendor Quote
7	Total Residential Meter Hardware Costs		$0	$1,900,395	$9,026,877	$9,026,877	$9,026,877	$9,026,877	$0	$0	$0	$0	$38,007,902	Line 2 * Line 6
8	Cost per C&I AMI Meter (Hardware)		$0	$169	$169	$169	$169	$169	$0	$0	$0	$0		Estimate based on Vendor Quote
9	Total C&I Meter Hardware Costs		$0	$347,048	$1,648,477	$1,648,477	$1,648,477	$1,648,477	$0	$0	$0	$0	$6,940,957	Line 3 * Line 8
10	Installation Cost per Residential Meter		$0	$20	$20	$20	$20	$20	$0	$0	$0	$0		DP&L Estimate
11	Total Residential, C&I Meter Install Costs		$0	$506,072	$2,403,840	$2,403,840	$2,403,840	$2,403,840	$0	$0	$0	$0	$10,121,433	(Line 2 + Line 3) * Line 10
12	Cost Per Polyphase C&I AMI Meter (Hardware)		$0	$225	$225	$225	$225	$225	$0	$0	$0	$0		Estimate based on Vendor Quote
13	Total Power Quality Meter Hardware Costs		$0	$188,066	$893,315	$893,315	$893,315	$893,315	$0	$0	$0	$0	$3,761,325	Line 4 * Line 12
14	Installation Cost per Polyphase C&I & Other Meter		$0	$124	$124	$124	$124	$124	$0	$0	$0	$0		DP&L Estimate
15	Total Polyphase C&I AMI Meter Installation Cost		$0	$103,361	$490,966	$490,966	$490,966	$490,966	$0	$0	$0	$0	$2,067,224	Line 4 * Line 14
16	Cost Per Other Meter (Hardware)		$0	$225	$225	$225	$225	$225	$0	$0	$0	$0		Estimate based on Vendor Quote
17	Total Other Meter Hardware Costs		$0	$3,758	$17,848	$17,848	$17,848	$17,848	$0	$0	$0	$0	$75,150	Line 5 * Line 16
18	Total Other Meter Installed Costs		$0	$2,065	$9,809	$9,809	$9,809	$9,809	$0	$0	$0	$0	$41,302	Line 5 * Line 14
19														
20	Total AMI Head End Hardware/Software	362-7	$378,000	$489,984	$500,176	$510,579	$521,199	$532,040	$543,107	$554,403	$565,935	$577,706	$5,173,130	Estimate based on Vendor Quote
21	Total AMI Field Equipment Cost	362-7	$2,691,780	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,691,780	Estimate based on Vendor Quote
22														
23	Total AMI Meter Investment		$3,069,780	$3,540,749	$14,991,308	$15,001,712	$15,012,332	$15,023,173	$543,107	$554,403	$565,935	$577,706	$68,880,204	Sum Lines 7,9,11,13,15,17,18,20,21
24														
25	Outsourced Consulting and Engineering Costs		$0	$895,584	$1,241,807	$1,267,637	$1,294,004	$1,160,692	$0	$0	$0	$0	$5,859,723	DP&L Estimate
26														
27	AMI AFUDC Costs	362-7	$239,443	$38,219	$39,014	$39,825	$40,654	$41,499	$42,362	$43,243	$44,143	$45,061	$613,463	DP&L Estimate
28	Smart Meter AFUDC Costs	370	$0	$0	$0	$1,229,184	$1,231,241	$1,220,842	$0	$0	$0	$0	$3,681,267	DP&L Estimate
29														
30	Smart Meter Cost of Existing Equipment		$0	$965,432	$4,585,802	$4,585,802	$4,585,802	$4,585,802	$0	$0	$0	$0	$19,308,641	
31														
32	**Total Incremental AMI Investment**	370	$3,309,223	$4,474,551	$16,272,129	$17,538,358	$17,578,229	$17,446,206	$585,469	$597,647	$610,078	$622,768	$79,034,657	Line 23 + Line 25 + Line 27 + Line 28

RESPONSES TO REQUESTS FOR PRODUCTION OF DOCUMENTS

RPD-1-001. Provide a copy of all formal and informal requests (e.g., interrogatories, data requests) made to the Company by the Commission, the PUCO Staff and/or the PUCO's Attorneys General in this proceeding and the Company's response to those data requests.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 3 (privileged and work product), 4 (proprietary), 7 (not in DP&L's possession or available on PUCO website), 8 (redact confidential information), 9 (vague or undefined), 10 (possession of DP&L's unregulated affiliate), 11 (calls for a legal conclusion), 12 (seeks information that DP&L does not know at this time). Subject to all general objections, DP&L states that it will produce responsive unprivileged documents in accordance with General Objection 8.

RPD-1-002. Provide a copy of all formal and informal requests (e.g., interrogatories, data requests) made to the Company by any other party in this proceeding and the Company's responses to those requests.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 3 (privileged and work product), 4 (proprietary), 7 (not in DP&L's possession or available on PUCO website), 8 (redact confidential information), 9 (vague or undefined), 10 (possession of DP&L's unregulated affiliate), 11 (calls for a legal conclusion), 12 (seeks information that DP&L does not know at this time). Subject to all general objections, DP&L states that it will produce responsive unprivileged documents in accordance with General Objection 8.

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Advanced Meter Infrastructure (AMI) Capital

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-1.1
Page 1 of 2
Witness Responsible: Kathryn Storm

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Summary of AMI Investment**													
2	Residential AMI Meters		0	23,176	110,084	110,084	110,084	110,084	0	0	0	0	463,511	DP&L Estimate
3	C&I AMI Meters		0	2,052	9,749	9,749	9,749	9,749	0	0	0	0	41,047	DP&L Estimate
4	Polyphase C&I AMI Meters		0	836	3,970	3,970	3,970	3,970	0	0	0	0	16,717	DP&L Estimate
5	Other C&I Meters		0	17	79	79	79	79	0	0	0	0	334	DP&L Estimate
6	Cost per Residential AMI Meter (Hardware)		$0	$82	$82	$82	$82	$82	$0	$0	$0	$0		Estimate based on Vendor Quote
7	Total Residential Meter Hardware Costs		$0	$1,900,395	$9,026,877	$9,026,877	$9,026,877	$9,026,877	$0	$0	$0	$0	$38,007,902	Line 2 * Line 6
8	Cost per C&I AMI Meter (Hardware)		$0	$169	$169	$169	$169	$169	$0	$0	$0	$0		Estimate based on Vendor Quote
9	Total C&I Meter Hardware Costs		$0	$347,048	$1,648,477	$1,648,477	$1,648,477	$1,648,477	$0	$0	$0	$0	$6,940,957	Line 3 * Line 8
10	Installation Cost per Residential Meter		$0	$20	$20	$20	$20	$20	$0	$0	$0	$0		DP&L Estimate
11	Total Residential, C&I Meter Install Costs		$0	$506,072	$2,403,840	$2,403,840	$2,403,840	$2,403,840	$0	$0	$0	$0	$10,121,433	(Line 2 + Line 3) * Line 10
12	Cost Per Polyphase C&I AMI Meter (Hardware)		$0	$225	$225	$225	$225	$225	$0	$0	$0	$0		Estimate based on Vendor Quote
13	Total Power Quality Meter Hardware Costs		$0	$188,066	$893,315	$893,315	$893,315	$893,315	$0	$0	$0	$0	$3,761,325	Line 4 * Line 12
14	Installation Cost per Polyphase C&I & Other Meter		$0	$124	$124	$124	$124	$124	$0	$0	$0	$0		DP&L Estimate
15	Total Polyphase C&I AMI Meter Installation Cost		$0	$103,361	$490,966	$490,966	$490,966	$490,966	$0	$0	$0	$0	$2,067,224	Line 4 * Line 14
16	Cost Per Other Meter (Hardware)		$0	$225	$225	$225	$225	$225	$0	$0	$0	$0		Estimate based on Vendor Quote
17	Total Other Meter Hardware Costs		$0	$3,758	$17,848	$17,848	$17,848	$17,848	$0	$0	$0	$0	$75,150	Line 5 * Line 16
18	Total Other Meter Installed Costs		$0	$2,065	$9,809	$9,809	$9,809	$9,809	$0	$0	$0	$0	$41,302	Line 5 * Line 14
19														
20	Total AMI Head End Hardware/Software	362-7	$378,000	$489,984	$500,176	$510,579	$521,199	$532,040	$543,107	$554,403	$565,935	$577,706	$5,173,130	Estimate based on Vendor Quote
21	Total AMI Field Equipment Cost	362-7	$2,691,780	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,691,780	Estimate based on Vendor Quote
22														
23	Total AMI Meter Investment		$3,069,780	$3,540,749	$14,991,308	$15,001,712	$15,012,332	$15,023,173	$543,107	$554,403	$565,935	$577,706	$68,880,204	Sum Lines 7,9,11,13,15,17,18,20,21
24														
25	Outsourced Consulting and Engineering Costs		$0	$895,584	$1,241,807	$1,267,637	$1,294,004	$1,160,692	$0	$0	$0	$0	$5,859,723	DP&L Estimate
26														
27	AMI AFUDC Costs	362-7	$239,443	$38,219	$39,014	$39,825	$40,654	$41,499	$42,362	$43,243	$44,143	$45,061	$613,463	DP&L Estimate
28	Smart Meter AFUDC Costs	370	$0	$0	$0	$1,229,184	$1,231,241	$1,220,842	$0	$0	$0	$0	$3,681,267	DP&L Estimate
29														
30	Smart Meter Cost of Existing Equipment		$0	$965,432	$4,585,802	$4,585,802	$4,585,802	$4,585,802	$0	$0	$0	$0	$19,308,641	
31														
32	**Total Incremental AMI Investment**	370	$3,309,223	$4,474,551	$16,272,129	$17,538,358	$17,578,229	$17,446,206	$585,469	$597,647	$610,078	$622,768	$79,034,657	Line 23 + Line 25 + Line 27 + Line 28

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Advanced Meter Infrastructure (AMI) O&M

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-1.1
Page 2 of 2
Witness Responsible: Kathryn Storm

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Summary of AMI O&M Costs**													
2	Annual Software Maintenance Fee of AMI Head-End	921	$0	$97,997	$100,035	$102,116	$104,240	$106,408	$108,621	$110,881	$113,187	$115,541	$959,026	DP&L Estimate
3	Annual Infrastructure O&M Costs	592 & 597	$134,589	$137,388	$140,246	$143,163	$146,141	$149,181	$152,284	$155,451	$158,685	$161,985	$1,479,114	DP&L Estimate
4	Total Equipment Maintenance		$134,589	$235,385	$240,281	$245,279	$250,381	$255,589	$260,905	$266,332	$271,872	$277,527	$2,438,140	Line 2 + Line 3
5														
6	Increased Call Center Costs	903												
7	Additional calls due to AMI/Smart Meters	903	0	5,216	24,776	24,776	24,776	24,776	0	0	0	0		DP&L Estimate
8	Cost per call		$5.00	$5.10	$5.21	$5.32	$5.43	$5.54	$5.66	$5.78	$5.90	$6.02		Company Records
9	Total additional Call Center Costs		$0	$26,623	$129,089	$131,774	$134,515	$137,313	$0	$0	$0	$0	$559,315	Line 7 * Line 8
10														
11	Total AMI O&M		$134,589	$262,008	$369,370	$377,053	$384,896	$392,902	$260,905	$266,332	$271,872	$277,527	$2,997,454	Line 4 + Line 9

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Customer Service System (CIS) Replacement Capital and O&M

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-1.3
Page 1 of 1
Witness Responsible: Antonio Narvaez

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Summary of CIS Capital Costs**													
2	CSS Modifications	303	$ 1,113,637	$ 1,805,477	$ 777,230	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,696,344	DP&L Estimate
3	CIS Replacement - Software Selection	303	$ 1,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000,000	DP&L Estimate
4	CIS Replacement - SI Selection	303	$ 1,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000,000	DP&L Estimate
5	CIS Replacement - BI Selection	303	$ -	$ 1,020,800	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,020,800	DP&L Estimate
6	CIS Replacement - Hardware/Infrastructure ($)	362	$ 2,107,776	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,107,776	DP&L Estimate
7	CIS Replacement - Upfront Software Licensing ($)	303	$ 3,161,664	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,161,664	DP&L Estimate
8	CIS Replacement - Internal Labor - Capital Costs	303	$ 6,118,800	$ 3,958,458	$ 83,154	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,160,412	DP&L Estimate
9	CIS Replacement - External Labor - Capital Costs	303	$ 15,212,205	$ 15,219,849	$ 1,719,323	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,151,376	DP&L Estimate
10	Total CIS Capital Costs	362 / 303	$ 29,714,082	$ 22,004,584	$ 2,579,707	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,298,373	Sum of lines 2-9
11														
12	**Summary of CIS O&M Costs**													
13	CIS Replacement - Ongoing Licensing		$ -	$ 710,034	$ 724,803	$ 739,878	$ 755,268	$ 770,977	$ 787,014	$ 803,384	$ 820,094	$ 837,152	$ 6,948,604	DP&L Estimate
14	Ongoing Labor - Operations & Maintenance		$ -	$ -	$ 521,016	$ 1,063,707	$ 1,085,832	$ 1,108,417	$ 1,131,472	$ 1,155,007	$ 1,179,031	$ 1,203,555	$ 8,448,038	DP&L Estimate
15	Total CIS O&M Costs	935	$ -	$ 710,034	$ 1,245,819	$ 1,803,585	$ 1,841,100	$ 1,879,395	$ 1,918,486	$ 1,958,391	$ 1,999,125	$ 2,040,707	$ 15,396,642	Sum of lines 13-14

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Utility Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-A
Page 1 of 2
Witness Responsible: Kevin Hall

Line No.	Description	FERC Account	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**O&M Savings Benefit Detail**													
2	Reduction in Customer Call Center Costs (DA/SA)	903	$ -	$ -	$ -	$ 33,288	$ 69,034	$ 105,182	$ 142,721	$ 183,815	$ 187,638	$ 191,541	$ 913,219	DP&L Estimate
3	Reduction of Residential Reconnect/Disconnect Costs (Smart Meters)		$ -	$ 32,490	$ 381,402	$ 710,960	$ 1,054,063	$ 1,411,131	$ 1,440,482	$ 1,470,444	$ 1,501,029	$ 1,532,251	$ 9,534,251	DP&L Estimate
4	Reduction in Meter Reading Labor Expense	902	$ -	$ 76,560	$ 527,529	$ 1,296,393	$ 2,097,013	$ 2,930,378	$ 3,394,417	$ 3,465,021	$ 3,537,094	$ 3,610,665	$ 20,935,070	DP&L Estimate
5	Reduction in Meter Reading Vehicle Expense	592	$ -	$ 5,250	$ 30,188	$ 55,125	$ 80,063	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 695,625	DP&L Estimate
6	Reduction in Meter Re-Read Expense (Smart Meters)	902	$ -	$ 5,325	$ 31,253	$ 58,258	$ 86,373	$ 115,632	$ 118,037	$ 120,492	$ 122,999	$ 125,557	$ 783,926	DP&L Estimate
7	Reduced Inventory Costs (EAM)	592	$ 200,000	$ 204,160	$ 208,407	$ 212,741	$ 217,166	$ 221,683	$ 226,294	$ 231,001	$ 235,806	$ 240,711	$ 2,197,971	DP&L Estimate
8	Reduction of Truck Rolls (MWFM)	592	$ 60,172	$ 61,424	$ 62,702	$ 192,017	$ 326,686	$ 333,481	$ 340,417	$ 347,498	$ 354,726	$ 362,104	$ 2,441,226	DP&L Estimate
9	Field Operational & Overtime Savings (MWFM)	592	$ 8,000	$ 8,166	$ 8,336	$ 25,529	$ 43,433	$ 44,337	$ 45,259	$ 46,200	$ 47,161	$ 48,142	$ 324,564	DP&L Estimate
10	Reduction in Customer Call Center Costs (Smart Meters)	903	$ -	$ -	$ -	$ -	$ -	$ 737,155	$ 752,487	$ 768,139	$ 784,116	$ 800,426	$ 3,842,324	DP&L Estimate
11	Reduction in Crew Costs (DA/SA)	592	$ 4,489	$ 9,164	$ 50,448	$ 93,104	$ 137,513	$ 183,729	$ 231,083	$ 235,889	$ 240,796	$ 245,804	$ 1,432,018	DP&L Estimate
12	Call Center Reductions due to Pre-Pay	903	$ -	$ -	$ -	$ 7,300	$ 17,903	$ 24,508	$ 213,215	$ 584,024	$ 866,766	$ 964,103	$ 2,677,819	DP&L Estimate
13	Reduction in Field Technician Costs due to Pre-Pay Customers	592	$ -	$ -	$ -	$ 2,190	$ 5,371	$ 7,352	$ 63,965	$ 175,207	$ 260,030	$ 289,231	$ 803,346	DP&L Estimate
14	Reduction in Mailing Cost for Pre-Paid Customers		$ -	$ -	$ -	$ 2,190	$ 5,371	$ 7,352	$ 63,965	$ 175,207	$ 260,030	$ 289,231	$ 803,346	DP&L Estimate
15	Reduction in Customer Call Center Costs (Customer Service)	903	$ -	$ 55,297	$ 112,894	$ 115,242	$ 117,639	$ 120,086	$ 122,584	$ 125,134	$ 127,737	$ 130,393	$ 1,027,007	DP&L Estimate
16	Reduction in Mainframe Maintenance (CIS Replacement)		$ -	$ -	$ 1,666,500	$ 1,666,500	$ 1,666,500	$ 1,833,150	$ 1,833,150	$ 1,833,150	$ 1,833,150	$ 1,833,150	$ 14,165,250	DP&L Estimate
17	Reduction in Mainframe Labor (CIS Replacement)	903	$ -	$ -	$ 459,322	$ 468,876	$ 478,629	$ 488,584	$ 498,747	$ 509,121	$ 519,710	$ 530,520	$ 3,953,509	DP&L Estimate
18	Total Projected O&M Benefits		$ 272,661	$ 457,835	$ 3,538,980	$ 4,939,715	$ 6,402,757	$ 8,668,740	$ 9,591,823	$ 10,375,342	$ 10,983,787	$ 11,298,829	$66,530,470	Sum Lines 2 - 17
19														
20	**Summary of Projected Deferred Capital Benefits**													
21	Residential Meter Avoided Capital (Smart Meters)		$ -	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 11,471,897	DP&L Estimate
22	Single Phase C&I Meter Avoided Capital (Smart Meters)		$ -	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 1,015,913	DP&L Estimate
23	Polyphase Meter Avoided Capital (Smart Meters)		$ -	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 1,880,663	DP&L Estimate
24	C&I Other Transformer Rated Meter Avoided Capital (Smart Meters)		$ -	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 24,048	DP&L Estimate
25	Savings for Distribution Transformer Reduced Capital (TLM)		$ 30,498	$ 252,018	$ 22,172	$ 85,775	$ 174,766	$ 191,417	$ 231,545	$ 196,331	$ 236,458	$ 189,506	$ 1,610,487	DP&L Estimate
26	Avoided Future CIS Replacement CapEx (CIS Replacement)		$ -	$ -	$ 746,939	$ 457,485	$ 467,001	$ 476,714	$ 486,630	$ 496,752	$ 507,084	$ 517,632	$ 4,156,237	DP&L Estimate
27	Total Projected Deferred Capital Benefits		$ 30,498	$ 1,851,187	$ 2,368,279	$ 2,142,429	$ 2,240,935	$ 2,267,301	$ 2,317,344	$ 2,292,252	$ 2,342,712	$ 2,306,307	$ 20,159,244	Sum Lines 21 - 26
28														
29	**Billing Process Efficiency Benefit Detail**													
30	Increase in Billing Process Efficiency due to New Meters (Smart Meters)		$ -	$ 31,290	$ 183,658	$ 343,453	$ 510,269	$ 683,207	$ 725,839	$ 796,267	$ 853,695	$ 883,429	$ 5,011,105	DP&L Estimate
31	Reconciliation of Unbilled Attachments (GIS)		$ 1,072,400	$ 2,189,412	$ 2,234,952	$ 2,281,439	$ 2,328,893	$ 2,377,333	$ 2,426,782	$ 2,477,259	$ 2,528,786	$ 2,581,385	$ 22,498,640	DP&L Estimate
32	Increase in Billing Process Efficiencies due to Reduction of Bad Debt Write-Offs (Customer Service/Operations)		$ -	$ 35,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 595,000	DP&L Estimate
33	Total Projected Enhanced Revenue Benefits		$ 1,072,400	$ 2,255,701	$ 2,488,609	$ 2,694,891	$ 2,909,162	$ 3,130,540	$ 3,222,621	$ 3,343,526	$ 3,452,481	$ 3,534,813	$ 28,104,745	Sum Lines 30 - 32

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Utility Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-A
Page 2 of 2
Witness Responsible: Kevin Hall

Line No.	Description	FERC Account	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	20 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**O&M Savings Benefit Detail**													
2	Reduction in Customer Call Center Costs (DA/SA)	903	$ 195,525	$ 199,592	$ 203,743	$ 207,981	$ 212,307	$ 216,723	$ 221,231	$ 225,833	$ 230,530	$ 235,325	$ 3,062,009	DP&L Estimate
3	Reduction of Residential Reconnect/Disconnect Costs (Smart Meters)		$ 1,564,122	$ 1,596,655	$ 1,629,866	$ 1,663,767	$ 1,698,373	$ 1,733,699	$ 1,769,760	$ 1,806,571	$ 1,844,148	$ 1,882,506	$ 26,723,719	DP&L Estimate
4	Reduction in Meter Reading Labor Expense	902	$ 3,685,767	$ 3,762,431	$ 3,840,689	$ 3,920,576	$ 4,002,124	$ 4,085,368	$ 4,170,344	$ 4,257,087	$ 4,345,634	$ 4,436,023	$ 61,441,113	DP&L Estimate
5	Reduction in Meter Reading Vehicle Expense	592	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 105,000	$ 1,745,625	DP&L Estimate
6	Reduction in Meter Re-Read Expense (Smart Meters)	902	$ 128,169	$ 130,835	$ 133,556	$ 136,334	$ 139,170	$ 142,064	$ 145,019	$ 148,036	$ 151,115	$ 154,258	$ 2,192,481	DP&L Estimate
7	Reduced Inventory Costs (EAM)	592	$ 245,718	$ 250,829	$ 256,046	$ 261,372	$ 266,808	$ 272,358	$ 278,023	$ 283,806	$ 289,709	$ 295,735	$ 4,898,374	DP&L Estimate
8	Reduction of Truck Rolls (MWFM)	592	$ 369,636	$ 377,324	$ 385,173	$ 393,184	$ 401,362	$ 409,711	$ 418,233	$ 426,932	$ 435,812	$ 444,877	$ 6,503,469	DP&L Estimate
9	Field Operational & Overtime Savings (MWFM)	592	$ 49,144	$ 50,166	$ 51,209	$ 52,274	$ 53,362	$ 54,472	$ 55,605	$ 56,761	$ 57,942	$ 59,147	$ 864,645	DP&L Estimate
10	Reduction in Customer Call Center Costs (Smart Meters)	903	$ 817,075	$ 834,070	$ 851,419	$ 869,128	$ 887,206	$ 905,660	$ 924,498	$ 943,727	$ 963,357	$ 983,395	$ 12,821,858	DP&L Estimate
11	Reduction in Crew Costs (DA/SA)	592	$ 250,917	$ 256,136	$ 261,464	$ 266,902	$ 272,454	$ 278,121	$ 283,905	$ 289,811	$ 295,839	$ 301,992	$ 4,189,557	DP&L Estimate
12	Call Center Reductions due to Pre-Pay	903	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 964,103	$ 12,318,848	DP&L Estimate
13	Reduction in Field Technician Costs due to Pre-Pay Customers	592	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 3,695,654	DP&L Estimate
14	Reduction in Mailing Cost for Pre-Paid Customers		$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 289,231	$ 3,695,654	DP&L Estimate
15	Reduction in Customer Call Center Costs (Customer Service)	903	$ 133,106	$ 135,874	$ 138,700	$ 141,585	$ 144,530	$ 147,537	$ 150,605	$ 153,738	$ 156,936	$ 160,200	$ 2,489,819	DP&L Estimate
16	Reduction in Mainframe Maintenance (CIS Replacement)		$ 2,016,465	$ 2,016,465	$ 2,016,465	$ 2,016,465	$ 2,016,465	$ 2,218,112	$ 2,218,112	$ 2,218,112	$ 2,218,112	$ 2,218,112	$ 35,338,133	DP&L Estimate
17	Reduction in Mainframe Labor (CIS Replacement)	903	$ 541,555	$ 552,819	$ 564,318	$ 576,056	$ 588,038	$ 600,269	$ 612,755	$ 625,500	$ 638,510	$ 651,791	$ 9,905,121	DP&L Estimate
18	Total Projected O&M Benefits		$ 11,644,761	$ 11,810,760	$ 11,980,212	$ 12,153,189	$ 12,329,764	$ 12,711,657	$ 12,895,654	$ 13,083,477	$ 13,275,208	$ 13,470,926	$ 191,886,079	Sum Lines 2 - 17
19														
20	**Summary of Projected Deferred Capital Benefits**													
21	Residential Meter Avoided Capital (Smart Meters)		$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 1,274,655	$ 24,218,450	DP&L Estimate
22	Single Phase C&I Meter Avoided Capital (Smart Meters)		$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 112,879	$ 2,144,706	DP&L Estimate
23	Polyphase Meter Avoided Capital (Smart Meters)		$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 208,963	$ 3,970,288	DP&L Estimate
24	C&I Other Transformer Rated Meter Avoided Capital (Smart Meters)		$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 2,672	$ 50,768	DP&L Estimate
25	Savings for Distribution Transformer Reduced Capital (TLM)		$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 30,498	$ 1,915,462	DP&L Estimate
26	Avoided Future CIS Replacement CapEx (CIS Replacement)		$ 528,398	$ 539,389	$ 550,608	$ 562,061	$ 573,752	$ 585,686	$ 597,868	$ 610,304	$ 622,998	$ 635,957	$ 9,963,258	DP&L Estimate
27	Total Projected Deferred Capital Benefits		$ 2,158,065	$ 2,169,056	$ 2,180,275	$ 2,191,728	$ 2,203,418	$ 2,215,353	$ 2,227,535	$ 2,239,970	$ 2,252,665	$ 2,265,623	$ 42,262,932	Sum Lines 21 - 26
28														
29	**Billing Process Efficiency Benefit Detail**													
30	Increase in Billing Process Efficiency due to New Meters (Smart Meters)		$ 898,775	$ 914,442	$ 930,433	$ 946,758	$ 963,422	$ 980,433	$ 997,797	$ 1,015,523	$ 1,033,617	$ 1,052,088	$ 14,744,393	DP&L Estimate
31	Reconciliation of Unbilled Attachments (GIS)		$ 2,635,078	$ 2,689,887	$ 2,745,837	$ 2,802,950	$ 2,861,252	$ 2,920,766	$ 2,981,518	$ 3,043,533	$ 3,106,839	$ 3,171,461	$ 51,457,760	DP&L Estimate
32	Increase in Billing Process Efficiencies due to Reduction of Bad Debt Write-Offs (Customer Service/Operations)		$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 70,000	$ 1,295,000	DP&L Estimate
33	Total Projected Enhanced Revenue Benefits		$ 3,603,853	$ 3,674,329	$ 3,746,270	$ 3,819,708	$ 3,894,674	$ 3,971,198	$ 4,049,315	$ 4,129,056	$ 4,210,456	$ 4,293,549	$ 67,497,154	Sum Lines 30 - 32

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Customer Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-B
Page 1 of 2
Witness Responsible: Tom Hulsebosch

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Energy and Demand Benefits**												
2													
3	Reduced cost of peak DEMAND from CVR ($)	$ -	$ -	$ -	$ -	$ -	$ -	$ 318,174	$ 644,677	$ 1,057,939	$ 1,624,088	$ 3,644,878	DP&L Estimate
4													
5	Reduced cost of purchased power from CVR ($)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,518,410	$ 3,124,914	$ 5,340,894	$ 7,313,385	$ 17,297,604	DP&L Estimate
6													
7	Annual Energy Savings from More Optimally Loaded Distribution Transformers	$ 8,340	$ 18,649	$ 30,058	$ 43,593	$ 58,517	$ 71,690	$ 86,280	$ 101,467	$ 130,065	$ 148,417	$ 697,075	DP&L Estimate
8													
9	Reduced unaccounted for energy due to theft reduction (Residential)	$ -	$ 86,622	$ 520,377	$ 1,010,717	$ 1,550,025	$ 2,044,233	$ 2,068,616	$ 2,089,107	$ 2,329,560	$ 2,353,683	$ 14,052,940	DP&L Estimate
10													
11	Reduced energy consumption due to theft reduction (Single Phase C&I)	$ -	$ 55,140	$ 331,249	$ 643,377	$ 986,678	$ 1,301,268	$ 1,316,789	$ 1,329,833	$ 1,482,894	$ 1,498,250	$ 8,945,479	DP&L Estimate
12													
13	Reduction in Energy Losses from Customers with Inactive Meters (CIM)	$ -	$ 17,324	$ 104,075	$ 202,143	$ 310,005	$ 408,847	$ 413,723	$ 417,821	$ 465,912	$ 470,737	$ 2,810,588	DP&L Estimate
14													
15	ePortal Energy Savings Value	$ -	$ 10	$ 2,182	$ 12,932	$ 42,553	$ 92,001	$ 111,718	$ 131,629	$ 167,748	$ 190,671	$ 751,444	DP&L Estimate
16													
17	Purchase Power Demand Savings due to TOU Rates and ePortal - Residential	$ -	$ 891	$ 1,331	$ 30,078	$ 193,730	$ 461,964	$ 745,497	$ 1,061,815	$ 1,548,420	$ 2,293,796	$ 6,337,523	DP&L Estimate
18													
19	Purchase Power Demand Savings due to TOU Rates and ePortal - Single Phase C&I	$ -	$ 171	$ 308	$ 5,049	$ 30,718	$ 72,113	$ 113,695	$ 159,117	$ 228,757	$ 334,857	$ 944,785	DP&L Estimate
20													
21	Purchase Power Demand Savings due to TOU Rates - Polyphase C&I	$ -	$ -	$ -	$ 5,032	$ 25,446	$ 52,321	$ 76,954	$ 102,706	$ 142,623	$ 203,277	$ 608,360	DP&L Estimate
22													
23	Purchase Power Demand Savings due to TOU Rates - Other C&I	$ -	$ -	$ -	$ 18,049	$ 90,503	$ 184,419	$ 268,758	$ 355,201	$ 488,411	$ 689,283	$ 2,094,623	DP&L Estimate
24													
25	Savings from Summer Energy Shift from On-Peak to Off-Peak with TOU Rates	$ -	$ -	$ -	$ 16,016	$ 84,352	$ 186,280	$ 291,655	$ 411,283	$ 568,368	$ 728,374	$ 2,286,328	DP&L Estimate
26													
27	Savings from Winter Energy Shift from On-Peak to Off-Peak with TOU Rates	$ -	$ -	$ -	$ 11,059	$ 58,049	$ 124,843	$ 202,857	$ 283,869	$ 346,088	$ 432,529	$ 1,459,293	DP&L Estimate
28													
29	Summer Energy Savings Benefits due to TOU Rates	$ -	$ -	$ -	$ 26,144	$ 137,948	$ 257,455	$ 338,720	$ 419,708	$ 548,559	$ 639,754	$ 2,368,286	DP&L Estimate
30													
31	Winter Energy Savings Benefits due to TOU Rates	$ -	$ -	$ -	$ 41,084	$ 216,775	$ 404,572	$ 532,275	$ 659,540	$ 862,021	$ 1,005,327	$ 3,721,593	DP&L Estimate
32													
33	Prepay Energy Benefits	$ -	$ -	$ -	$ 3,790	$ 11,778	$ 18,916	$ 190,313	$ 592,262	$ 1,089,069	$ 1,223,915	$ 3,130,042	DP&L Estimate
34													
35	Prepay Demand Benefits	$ -	$ -	$ -	$ 1,920	$ 6,257	$ 9,091	$ 84,248	$ 233,871	$ 379,130	$ 485,825	$ 1,200,341	DP&L Estimate
36													
37	Battery Storage - Initial Pilot - Summer Demand Shift	$ -	$ -	$ -	$ 1,313	$ 2,767	$ 2,737	$ 2,835	$ 2,849	$ 2,952	$ 2,944	$ 18,398	DP&L Estimate
38	Battery Storage - Initial Pilot - Winter Demand Shift	$ -	$ -	$ -	$ 907	$ 1,904	$ 1,834	$ 1,972	$ 1,967	$ 1,798	$ 1,748	$ 12,130	DP&L Estimate
39	Battery Storage - Pilot Extension - Summer Demand Shift	$ -	$ -	$ -	$ -	$ 9,224	$ 18,244	$ 18,903	$ 18,995	$ 19,680	$ 19,626	$ 104,672	DP&L Estimate
40	Battery Storage - Pilot Extension - Winter Demand Shift	$ -	$ -	$ -	$ -	$ 6,348	$ 12,227	$ 13,148	$ 13,110	$ 11,983	$ 11,654	$ 68,470	DP&L Estimate
41													
42	Lower Energy Cost from shifting EVs to off-peak charging	$ -	$ 9,559	$ 35,428	$ 85,663	$ 165,197	$ 246,710	$ 335,214	$ 402,752	$ 474,338	$ 559,584	$ 2,314,446	DP&L Estimate
43	Avoided Peak Demand Increase due to EV Intelligent Charging	$ -	$ 796	$ 24,279	$ 205,375	$ 755,715	$ 1,666,396	$ 2,371,151	$ 2,972,898	$ 3,991,286	$ 5,394,932	$ 17,382,828	DP&L Estimate
44													
45	**Improved Reliability**												
46													
47	Average Residential customer benefit per minute from reduced outages (DA/SA)	$ -	$ -	$ -	$ 319,317	$ 552,816	$ 738,560	$ 895,171	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 5,546,797	DP&L Estimate
48	Average C&I Single Phase customer benefit per minute from reduced outages (DA/SA)	$ -	$ -	$ -	$ 6,884,240	$ 11,460,691	$ 15,058,506	$ 19,041,306	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 116,704,380	DP&L Estimate
49	Average C&I Poly Phase customer benefit per minute from reduced outages (DA/SA)	$ -	$ -	$ -	$ 783,963	$ 1,636,265	$ 2,346,167	$ 2,800,070	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 17,155,804	DP&L Estimate
50													
51	Average Residential customer benefit per minute from reduced outages (AMI)	$ -	$ 1,905	$ 11,181	$ 20,842	$ 30,901	$ 41,368	$ 42,229	$ 43,107	$ 44,004	$ 44,919	$ 280,456	DP&L Estimate
52	Average C&I Single Phase customer benefit per minute from reduced outages (AMI)	$ -	$ 35,889	$ 210,656	$ 392,677	$ 582,179	$ 779,394	$ 795,605	$ 812,154	$ 829,047	$ 846,291	$ 5,283,890	DP&L Estimate
53	Average C&I Poly Phase customer benefit per minute from reduced outages (AMI)	$ -	$ 105,489	$ 619,179	$ 1,154,192	$ 1,711,194	$ 2,290,868	$ 2,338,518	$ 2,387,159	$ 2,436,812	$ 2,487,498	$ 15,530,908	DP&L Estimate
54													
55	**Customer EV Savings**	$ -	$ 167,188	$ 616,411	$ 1,358,331	$ 2,495,348	$ 3,855,635	$ 5,037,756	$ 6,116,922	$ 7,088,399	$ 8,397,859	$ 35,133,850	DP&L Estimate
56													
57	**Total Customer Benefits**	$ 8,340	$ 499,634	$ 2,506,713	$ 13,277,803	$ 23,213,881	$ 32,748,659	$ 42,372,560	$ 50,520,701	$ 57,706,725	$ 65,033,192	$ 287,888,210	Sum Lines 1-55
58													

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Customer Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-B
Page 2 of 2
Witness Responsible: Tom Hulsebosch

Line No.	Description	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	20 Yr Total Sum (D)-(M)	Source
(A)	(B)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
1	**Energy and Demand Benefits**												
2													
3	Reduced cost of peak DEMAND from CVR ($)	$ 2,155,714	$ 2,187,845	$ 2,228,740	$ 2,193,688	$ 2,196,609	$ 2,231,661	$ 2,222,898	$ 2,167,398	$ 2,222,898	$ 2,135,267	$ 25,587,595	DP&L Estimate
4													
5	Reduced cost of purchased power from CVR ($)	$ 9,111,508	$ 9,245,500	$ 9,283,784	$ 9,354,307	$ 9,435,911	$ 9,532,628	$ 9,480,240	$ 9,560,837	$ 9,719,009	$ 9,739,158	$ 111,760,484	DP&L Estimate
6													
7	Annual Energy Savings from More Optimally Loaded Distribution Transformers	$ 162,719	$ 180,122	$ 195,940	$ 212,615	$ 229,789	$ 247,621	$ 261,651	$ 279,398	$ 299,799	$ 316,232	$ 3,082,961	DP&L Estimate
8													
9	Reduced unaccounted for energy due to theft reduction (Residential)	$ 2,345,901	$ 2,380,400	$ 2,390,256	$ 2,408,413	$ 2,429,424	$ 2,454,325	$ 2,440,837	$ 2,461,588	$ 2,502,312	$ 2,507,499	$ 38,373,895	DP&L Estimate
10													
11	Reduced energy consumption due to theft reduction (Single Phase C&I)	$ 1,493,297	$ 1,515,257	$ 1,521,531	$ 1,533,089	$ 1,546,464	$ 1,562,315	$ 1,553,729	$ 1,566,938	$ 1,592,861	$ 1,596,163	$ 24,427,122	DP&L Estimate
12													
13	Reduction in Energy Losses from Customers with Inactive Meters (CIM)	$ 469,180	$ 476,080	$ 478,051	$ 481,683	$ 485,885	$ 490,865	$ 488,167	$ 492,318	$ 500,462	$ 501,500	$ 7,674,779	DP&L Estimate
14													
15	ePortal Energy Savings Value	$ 211,156	$ 235,687	$ 258,178	$ 260,139	$ 262,409	$ 265,098	$ 263,641	$ 265,883	$ 270,281	$ 270,842	$ 3,314,758	DP&L Estimate
16													
17	Purchase Power Demand Savings due to TOU Rates and ePortal - Residential	$ 2,784,585	$ 3,201,385	$ 3,563,212	$ 3,576,684	$ 3,620,451	$ 3,718,285	$ 3,744,024	$ 3,690,310	$ 3,826,034	$ 3,715,242	$ 41,777,735	DP&L Estimate
18													
19	Purchase Power Demand Savings due to TOU Rates and ePortal - Single Phase C&I	$ 403,358	$ 460,609	$ 510,044	$ 509,927	$ 513,074	$ 523,781	$ 524,246	$ 513,628	$ 529,327	$ 510,919	$ 5,943,697	DP&L Estimate
20													
21	Purchase Power Demand Savings due to TOU Rates - Polyphase C&I	$ 238,688	$ 266,987	$ 297,678	$ 321,760	$ 347,835	$ 379,580	$ 404,320	$ 419,937	$ 457,200	$ 464,775	$ 4,207,120	DP&L Estimate
22													
23	Purchase Power Demand Savings due to TOU Rates - Other C&I	$ 802,355	$ 888,468	$ 981,166	$ 1,047,481	$ 1,120,956	$ 1,210,932	$ 1,276,857	$ 1,312,810	$ 1,414,895	$ 1,423,844	$ 13,574,387	DP&L Estimate
24													
25	Savings from Summer Energy Shift from On-Peak to Off-Peak with TOU Rates	$ 825,036	$ 945,325	$ 1,028,834	$ 1,037,413	$ 1,045,718	$ 1,067,388	$ 1,047,337	$ 1,080,876	$ 1,108,560	$ 1,096,187	$ 12,569,002	DP&L Estimate
26													
27	Savings from Winter Energy Shift from On-Peak to Off-Peak with TOU Rates	$ 490,855	$ 572,102	$ 625,346	$ 622,757	$ 618,125	$ 634,844	$ 597,650	$ 637,116	$ 655,847	$ 622,409	$ 7,536,343	DP&L Estimate
28													
29	Summer Energy Savings Benefits due to TOU Rates	$ 724,060	$ 823,404	$ 894,404	$ 906,878	$ 920,319	$ 936,878	$ 935,518	$ 952,413	$ 975,254	$ 981,156	$ 11,418,570	DP&L Estimate
30													
31	Winter Energy Savings Benefits due to TOU Rates	$ 1,137,809	$ 1,293,920	$ 1,405,492	$ 1,425,094	$ 1,446,216	$ 1,472,236	$ 1,470,100	$ 1,496,648	$ 1,532,543	$ 1,541,817	$ 17,943,468	DP&L Estimate
32													
33	Prepay Energy Benefits	$ 1,219,869	$ 1,237,808	$ 1,242,933	$ 1,252,375	$ 1,263,300	$ 1,276,249	$ 1,269,235	$ 1,280,026	$ 1,301,202	$ 1,303,900	$ 15,776,939	DP&L Estimate
34													
35	Prepay Demand Benefits	$ 518,517	$ 531,913	$ 547,903	$ 550,097	$ 556,879	$ 571,980	$ 575,991	$ 567,779	$ 588,713	$ 571,716	$ 6,781,831	DP&L Estimate
36													
37	Battery Storage - Initial Pilot - Summer Demand Shift	$ 2,937	$ 3,007	$ 3,026	$ 3,029	$ 3,031	$ 3,072	$ 2,993	$ 3,067	$ 3,124	$ 3,067	$ 48,752	DP&L Estimate
38	Battery Storage - Initial Pilot - Winter Demand Shift	$ 1,747	$ 1,820	$ 1,839	$ 1,818	$ 1,792	$ 1,827	$ 1,708	$ 1,808	$ 1,848	$ 1,742	$ 30,079	DP&L Estimate
39	Battery Storage - Pilot Extension - Summer Demand Shift	$ 19,580	$ 20,044	$ 20,173	$ 20,194	$ 20,210	$ 20,481	$ 19,954	$ 20,448	$ 20,825	$ 20,450	$ 307,032	DP&L Estimate
40	Battery Storage - Pilot Extension - Winter Demand Shift	$ 11,649	$ 12,131	$ 12,262	$ 12,123	$ 11,946	$ 12,182	$ 11,387	$ 12,053	$ 12,321	$ 11,611	$ 188,134	DP&L Estimate
41													
42	Lower Energy Cost from shifting EVs to off-peak charging	$ 669,575	$ 810,738	$ 954,606	$ 1,117,249	$ 1,285,957	$ 1,454,989	$ 1,532,043	$ 1,720,884	$ 1,878,159	$ 1,921,258	$ 15,659,903	DP&L Estimate
43	Avoided Peak Demand Increase due to EV Intelligent Charging	$ 6,798,711	$ 8,029,456	$ 9,460,087	$ 10,830,381	$ 12,422,037	$ 14,198,009	$ 15,674,608	$ 16,719,612	$ 18,534,332	$ 19,016,638	$ 149,066,699	DP&L Estimate
44													
45	**Reliability Benefits**												
46													
47	Average Residential customer benefit per minute from reduced outages (DA/SA)	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 1,013,644	$ 15,683,241	DP&L Estimate
48	Average C&I Single Phase customer benefit per minute from reduced outages (DA/SA)	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 21,419,878	$ 330,903,165	DP&L Estimate
49	Average C&I Poly Phase customer benefit per minute from reduced outages (DA/SA)	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 3,196,447	$ 49,120,270	DP&L Estimate
50													
51	Average Residential customer benefit per minute from reduced outages (AMI)	$ 45,853	$ 46,807	$ 47,781	$ 48,774	$ 49,789	$ 50,825	$ 51,882	$ 52,961	$ 54,062	$ 55,187	$ 784,377	DP&L Estimate
52	Average C&I Single Phase customer benefit per minute from reduced outages (AMI)	$ 863,894	$ 881,863	$ 900,205	$ 918,930	$ 938,043	$ 957,555	$ 977,472	$ 997,803	$ 1,018,558	$ 1,039,744	$ 14,777,956	DP&L Estimate
53	Average C&I Poly Phase customer benefit per minute from reduced outages (AMI)	$ 2,539,238	$ 2,592,054	$ 2,645,969	$ 2,701,005	$ 2,757,186	$ 2,814,535	$ 2,873,077	$ 2,932,837	$ 2,993,840	$ 3,056,112	$ 43,436,761	DP&L Estimate
54													
55	**Customer EV Savings**	$ 10,031,130	$ 11,953,279	$ 14,195,196	$ 16,945,428	$ 19,921,454	$ 22,550,512	$ 25,242,291	$ 27,810,524	$ 30,228,841	$ 32,014,616	$ 246,027,120	DP&L Estimate
56													
57	**Total Customer Benefits**	$ 71,708,889	$ 76,423,977	$ 81,324,605	$ 85,923,299	$ 91,080,777	$ 96,270,621	$ 100,573,826	$ 104,647,868	$ 109,873,077	$ 112,069,022	$ 1,217,784,172	Sum Lines 1-55
58													

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Societal Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-C
Page 1 of 2
Witness Responsible: Tom Hulsebosch

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	10 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	**Summary of Total Societal Benefits**												
2													
3	Reduced Greenhouse Gas												
4	Tons of GHS Savings through Reduced Vehicle Miles due to MWFS	28	28	28	85	142	142	142	142	142	142	1,025	DP&L Estimate
5	Tons of GHG Saved from Optimized Distribution (VVO and CVR)	0	0	0	0	0	0	28,179	57,423	88,014	119,284	292,900	DP&L Estimate
6	Tons of GHS Savings Reduced for Unaccounted Energy (CIM and Theft)	0	3,525	20,270	37,015	53,759	70,504	70,504	70,504	70,504	70,504	467,090	DP&L Estimate
7	Tons of GHG Savings due to Few Truck Rolls due to decrease in Meter Investigations and Connect/Disc	0	11	64	117	170	224	224	224	224	224		DP&L Estimate
8	Tons of GHS Savings Through reduced consumer consumption due to ePortal and TOU rates	0	0	46	1,445	6,793	12,914	16,592	20,269	23,947	27,625	109,631	DP&L Estimate
9	Tons of GHS Savings Through Pre-Pay	0	0	0	76	222	355	3,532	10,883	17,947	19,962	52,978	DP&L Estimate
10	Tons of GHS Savings Associated with Conversion of Gasoline to Electric Vehicles	0	274	956	2,000	3,576	5,328	6,721	7,879	8,758	9,738	45,230	DP&L Estimate
11	Tons of GHG Savings from TLM	196	413	638	869	1,105	1,346	1,601	1,865	2,143	2,421	12,598	DP&L Estimate
12	Tons of GHG Savings from Community Solar Demonstration	0	0	0	988	4,938	7,901	7,901	7,901	7,901	7,901	45,433	DP&L Estimate
13													
14	Cost of GHG per Ton	$ 9.18	$ 9.83	$ 9.89	$ 9.94	$ 10.60	$ 10.60	$ 11.20	$ 11.20	$ 11.20	$ 11.80		Estimate
15	**Annual GHG Savings**	$ 2,063	$ 41,812	$ 217,559	$ 423,519	$ 749,319	$ 1,046,137	$ 1,516,053	$ 1,982,911	$ 2,458,678	$ 3,041,210	$ 11,479,261	Sum Lines 4-12 * Line 14
16													
17	**Economic Impact**	$ 138,487,296	$ 178,871,403	$ 144,243,005	$ 116,705,602	$ 129,901,162	$ 95,743,109	$ 65,136,674	$ 8,908,197	$ 9,083,240	$ 9,261,925	$ 896,341,613	Estimate

The Dayton Power and Light Company
Case No. 18-1875-EL-GRD
Distribution Modernization Plan
Societal Benefits

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).:

WP-C
Page 2 of 2
Witness Responsible: Tom Hulsebosch

Line No.	Description	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	20 Yr Total Sum (D)-(M)	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	**Summary of Total Societal Benefits**												
2													
3	Green House Gas Reduction												
4	Tons of GHS Savings through Reduced Vehicle Miles due to MWFS	142	142	142	142	142	142	142	142	142	142	2,449	DP&L Estimate
5	Tons of GHG Saved from Optimized Distribution (VVO and CVR)	149,105	149,105	149,105	149,105	149,105	149,105	149,105	149,105	149,105	149,105	1,783,947	DP&L Estimate
6	Tons of GHS Savings Reduced for Unaccounted Energy (CIM and Theft)	70,504	70,504	70,504	70,504	70,504	70,504	70,504	70,504	70,504	70,504	1,172,132	DP&L Estimate
7	Tons of GHG Savings due to Few Truck Rolls due to decrease in Meter Investigations and Connect/Disc	224	224	224	224	224	224	224	224	224	224		DP&L Estimate
8	Tons of GHS Savings Through reduced consumer consumption due to ePortal and TOU rates	31,302	34,980	37,856	38,047	38,238	38,429	38,619	38,810	39,001	39,192	484,106	DP&L Estimate
9	Tons of GHS Savings Through Pre-Pay	19,962	19,962	19,962	19,962	19,962	19,962	19,962	19,962	19,962	19,962	252,603	DP&L Estimate
10	Tons of GHS Savings Associated with Conversion of Gasoline to Electric Vehicles	10,869	12,518	14,337	16,524	18,764	20,529	22,140	23,580	24,827	24,589	233,908	DP&L Estimate
11	Tons of GHG Savings from TLM	2,663	2,905	3,147	3,389	3,631	3,873	4,115	4,357	4,599	4,841	50,119	DP&L Estimate
12	Tons of GHG Savings from Community Solar Demonstration	7,901	7,901	7,901	7,901	7,901	7,901	7,901	7,901	7,901	7,901	124,446	
13													
14	Cost of GHG per Ton	$ 11.85	$ 12.51	$ 12.56	$ 13.22	$ 13.27	$ 13.98	$ 14.09	$ 14.80	$ 14.91	$ 15.62		Estimate
15	**Annual GHG Savings**	$ 3,468,702	$ 3,729,950	$ 3,808,407	$ 4,041,501	$ 4,093,823	$ 4,343,491	$ 4,406,518	$ 4,656,194	$ 4,715,900	$ 4,943,410	$ 53,687,158	Sum Lines 4-12 * Line 14
16													
17	**Economic Impact**	$ 4,477,956	$ 4,571,097	$ 4,666,176	$ 4,763,232	$ 4,862,308	$ 4,963,444	$ 5,066,683	$ 5,172,070	$ 5,279,649	$ 5,389,466	$ 945,553,694	Estimate

INT-1-34. The Stipulation and Recommendation on page 6 indicates that the IIR recovery of costs will cease and the IIR shall be set to zero if DP&L does not file a distribution rate case by January 1, 2025.

a) If DP&L does not file a distribution rate case by January 1, 2025, will the operational savings continue to be credited to customers until DP&L files a distribution rate case?

b) If so, what is the level of operational savings that will be credited to consumers on an annual basis after 2025?

c) Will the operational savings continue to be credited to customers through the IIR?

d) Assuming that DP&L files a distribution rate case by January 1, 2025, when does the Company expect to file a rate case subsequent to this rate case?

e) Does the Stipulation include any provisions associated with dates when subsequent rate cases must be filed?

RESPONSE: General Objections Nos. 3 (privileged and work product), 11 (calls for a legal conclusion), 13 (mischaracterization). DP&L further objects because this request seeks work product information. DP&L further objects because it does not know what will happen in the future.

PJA-04

FILED UNDER SEAL

INTENTIONALLY OMITTED

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

12/18/2020 11:03:56 AM

in

Case No(s). 18-1875-EL-GRD, 18-1876-EL-WVR, 18-1877-EL-AAM, 19-1121-EL-UNC, 20-0680-EL-UNC

Summary: Testimony Public Version Direct Testimony of Paul J. Alvarez, President, Wired Group In Opposition to the Joint Stipulation and Recommendation on Behalf of The Office of The Ohio Consumers' Counsel electronically filed by Mrs. Tracy J Greene on behalf of O'Brien, Angela D