BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 18-1875-EL-GRD
18-1876-EL-WVR
18-1877-EL-AAM

Distribution Modernization Plan

DIRECT TESTIMONY
OF DONALD A. GEBELE

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

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Donald A. Gebele. My business address is 1900 Dryden Road, Dayton, Ohio 45439.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as Director, Operations.

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

A. I assumed my present position in July 2010. Prior to that time, I was Manager, System Operations at DPL Inc. from May 2007 until July 2010.

Q. What are your responsibilities in your current position and to whom do you report?

A. In my current position, I am responsible for system operating, trouble call dispatch, and NERC compliance. I report to the Sr. Director of Operations, Bruce Coppock.

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

A. I received a Bachelor of Science Degree in Engineering from Wright State University in 1985 and a Bachelor of Science Degree in Electrical Engineering in 1990. I graduated from Xavier University with a Master of Business Administration in 2010. I have held a variety of roles within DP&L including distribution planning, operations management, reliability operations, and vegetation management.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to support and explain the programs and systems that support the Self-Healing Grid component of DP&L's Distribution Modernization Plan ("DMP"), including Field Automation, Substation Automation, Operational Communications Infrastructure, and Operational Analytics.[1] Additionally, I support the Telecommunication component and the capabilities required to ensure reliable and robust communication with all the field devices proposed as part of the DMP.

Q. Which workpapers are you supporting?

A. I am supporting the following workpapers:

1. WP-2.1 – Distribution Automation ("DA")
2. WP-2.2 – Substation Automation ("SA")
3. WP-2.3 – Advanced Distribution Management System ("ADMS")
4. WP-2.4 – Conservation Voltage Reduction ("CVR"), Volt/VAR Optimization ("VVO")
5. WP-2.6 – Geographic Information System ("GIS")
6. WP-2.7 – Mobile Workforce Management System ("MWFM")
7. WP-3.2 (line 8) – Customer ePortal / Mobile App Capital and O&M
8. WP-5.0 – Telecommunications

[1] The nomenclature used to describe these groups of technologies aligns with those outlined on pages 15 and 16 of *PowerForward: A Roadmap to Ohio's Electricity Future.*

II. OVERVIEW OF SCOPE OF PROJECTS

Q. Please describe DP&L's plan for implementing technology systems and telecommunications as part of its DMP.

A. DP&L proposes a multi-year plan for the implementation of new systems that will provide a self-healing grid which will streamline operations, improving distribution network reliability, and enhancing customer service. The technology systems, including an ADMS, CVR/VVO, Geographic Information System ("GIS") Expansion, MWFM and Telecommunication infrastructure, will support DA and SA. Additionally, investments in operational communications infrastructure will be needed to support all aspects of the program.

Q. What is included in the scope of DP&L's cost estimates?

A. DP&L's estimates include the cost of hardware, software, and labor required to implement each system completely through all phases of the system development lifecycle. The estimates also include the costs of ongoing maintenance within a period of 20 years from the start of the DMP to support the operation of these systems.

Q. Are the implementation estimates and timelines appropriate and reasonable?

A. Yes, the dollar investments outlined in the corresponding Workpapers are reasonable and prudent. DP&L will have a formal project management office as described by Witness Hall, that will be established to ensure standard and reliable methods are used to execute projects. Appropriate governance, testing, and internal and external labor costs were added to the estimates based on DP&L's experience with similar projects in the past including the deployment of the MPLS and two-way radio systems and the migration to an SAP based ERP system. We have also leveraged the experiences from our sister company, Indianapolis Power and Light, to validate that the estimates are reasonable and prudent.

DP&L's implementation strategy that takes into consideration the relative complexities and interdependencies of the various systems and interfaces that will be required to achieve the vision of the DMP. Each system estimate was subjected to several reviews for reasonableness by soliciting the opinions of internal and external software project managers and support personnel, who have experience with similar programs. DP&L will further refine its technology system costs upon completion of a comprehensive, formal RFP process that will be employed to evaluate and select the systems required to support the current and future operating needs of the future-state distribution system.

Q. Will there be controls in place to ensure project success?

A. Yes, consistent with program and project management principles, there are mechanisms and processes to manage the project effectively to facilitate success. These processes include but are not limited to: quality management; status reporting; effective work planning; issue/risk management; scope and change management; and budget/ financial management. The IT department at DP&L has developed and instituted an Enterprise Project Management Methodology ("EPMM") that will be followed for the DMP Programs to ensure successful completion. The EPMM is managed by the IT Department's PMO. DP&L's EPMM is currently in use to control, monitor, and support the successful execution and completion of all enterprise technology initiatives. IT PMO resources are using the EPMM to achieve success.

Q. Are DP&L's DMP components consistent with existing open standards?

A. Yes. While there may not be a universally agreed upon set of 'open' standards related to the operations of a distribution system, the infrastructure to be installed as part of DP&L's DMP will integrate and communicate with many management and control systems that are currently available in the market. To best align with the PowerForward guidance on supporting existing and open standards DP&L will select equipment for the various systems that utilize specific and open standards where possible. Doing so will allow DP&L to effectively integrate these systems with other existing, new, and future systems as well as with DP&L's existing core network infrastructure. This familiarity will allow the Company engineers and technicians to seamlessly design, configure and install components for new and future equipment.

Q. What specific standards will be used across the DMP's Self-Healing Grid systems?

A. The DMP will use engineering standards for substation and distribution systems from the Institute of Electrical and Electronics Engineers ("IEEE") and the International Electrotechnical Commission ("IEC") for communications, safety, configuration, construction, and operations, where applicable. Additionally, by utilizing open communication, security, engineering, integration and operational standards as defined by the National Institute of Standards and Technology ("NIST") for Smart Grid Cyber Security in NISTR-7628, DP&L will ensure that industry adopted standards for component and system cyber security and communications protocols are followed. Further, as is typical in a utility, engineering practices will continue to be based on the applicable standards from NEC, NFPA, NEMA, OSHA and others.

III. DISTRIBUTION/SUBSTATION AUTOMATION ("DA/SA")

Q. What is the purpose of DA and SA?

A. DA and SA offer enhanced capabilities to isolate and identify line faults, which aim to minimize the impact of service disruptions. To realize the reliability improvements enabled by real-time distribution of substation loads under fault conditions, DP&L will simultaneously deploy DA/SA equipment throughout the deployment period. This equipment will also allow DP&L to reconfigure the distribution system based upon changing conditions due to customer integration of Distributed Energy Resources ("DERs") and load profile alterations.

Q. How do you plan to execute the DA and SA initiatives under DP&L's DMP?

A. The initial phase for the reliability enhancements portion of the DMP focuses on SA by upgrading the communication systems and relays (electromechanical to digital) in substations to enable fault isolation and load redistribution in conjunction with the DA technology being deployed. Additionally, DP&L will implement DA technology, which requires the installation of a series of controls, switches, and monitors—such as capacitor banks, regulators, reclosers, and line sensors—as well as additions to the supporting communication infrastructure. DP&L will incorporate an approach that prioritizes DA and SA initiatives, in part, based on reliability and efficiency needs. DP&L proposes a seven-year infrastructure deployment plan, through which the Company will deploy various technologies that are critical to improving operations on DP&L's grid.

Q. How does DP&L currently monitor and manage its distribution system?

A. The distribution system comprises a variety of operating devices such as air break switches, single and three-phase reclosers, fixed and switched capacitor banks, and voltage regulators. Manual switches and reclosers are used to sectionalize circuits and to pick up load during planned and unplanned events. Reclosers are programmed to react automatically to fault conditions and to minimize the number of affected customers. Capacitor banks and regulators are set to maintain voltage and maximize the power factor along the feeder which, in turn, minimizes line losses. Simple controls operate at pre-set times or temperature set points. More complex controls evaluate voltage and reactive power to determine optimal operation. Each device operates independently of the other devices on the circuit; there is no communication between the various components or a centralized control system. These devices are not currently monitored or controlled by the system operators who currently have visibility only into substations via the existing Transmission Supervisory Control and Data Acquisition ("T-SCADA") system. The result is a manually operated distribution system.

A. DISTRIBUTION AUTOMATION

Q. Please explain how DA works.

A. DA utilizes a combination of sensors, switches, monitors, and controls to enable automated rerouting of power flows and fault isolation. Each monitor and control device will use two-way communications to interface with operators and systems—either through Distribution Management System ("DMS") suggested actions with operator confirmation or directly, via system-controlled actions—to respond quickly to adverse events on the distribution system. DA enables systems and system operators to simultaneously reconfigure and re-energize the distribution system to minimize the number of affected customers following an adverse event.

Q. How does DP&L plan to deploy DA?

A. DP&L will deploy automation technology on circuits across its regions based on opportunities to strengthen reliability, utilize strong tie capabilities between circuits, and benefit the greatest number of customers during restoration efforts. DP&L's DA deployment plan includes two elements:

i. Deploying field devices and equipment; and

ii. Implementing supporting technology systems.

Q. Which device types are included as part of DP&L's DA project plan?

A. The field devices and equipment that DP&L intends to deploy, along with their corresponding benefits, are summarized in the following table:

Field Devices and Equipment	Primary Benefit
Automatic Reclosers	Minimize number of customers affected by a fault
Smart Switches	Control in re-energizing sections of circuits during outage events
Capacitor Banks with Controls	Facilitate Volt/VAR Optimization
Air Break Switch Controls	System load balancing and circuit isolation capabilities
Single Phase Sensors	Automate load monitoring and fault detection
Voltage Regulator Controls	Improved power quality; energy and demand savings

Q. Please describe Automatic Reclosers.

A. Automatic reclosers are a class of switchgear that is designed for use on overhead electricity distribution networks to detect and interrupt momentary faults. DP&L plans to install three-phase reclosers with communications and controls to minimize the number of customers affected by circuit operations. These devices operate automatically to isolate or restore faulted line sections and will be used for circuit reconfiguration schemes.

Q. Please describe Smart Switches.

A. Smart switches are automated devices that are capable of opening and closing in response to signals sent from embedded intelligence in the switches' local controls, a centralized computer, or utility personnel in a control center. DP&L will deploy smart switches across its service territory. Smart switches allow for improved control in re-energizing sections of distribution circuits during outage events. Additionally, smart switches will reduce the wear and tear on distribution facilities from repeatedly reclosing into a faulted line.

Q. Please describe Capacitor Banks with Controls.

A. A capacitor bank is a grouping of several identical capacitors interconnected in parallel or in series with one another. These groups of capacitors are used to correct or counteract undesirable characteristics, such as power factor lag or phase shifts. As part of this DMP, DP&L will analyze each distribution circuit's reactive power and develop a master plan for both fixed and switched capacitor banks. DP&L may install new capacitor banks or existing banks may be utilized, re-deployed, or re-built with new controls and communications. The ability to control capacitor banks will allow for Volt/VAR Optimization ("VVO"). VVO increases overall system efficiency by improving feeder power factor, which results in a more consistent voltage profile across the entire circuit. The voltage can then be reduced via controls, thereby reducing overall demand and energy consumption. A reduction in line losses is an additional benefit of improved power factor. Voltage levels, while reduced, will still meet or exceed the industry-required range to provide consistent quality service to the customer.

Q. Please describe Air Break Switch Controls.

A. Motor operators and associated communications devices will be installed on certain unitized existing air break switches. This additional equipment is required to integrate the existing switches into the DA program and will be selectively installed on those switches capable of integrating with the motor operator mechanism. These switches are used to isolate circuit sections and to pick up load from other sources resulting in the elimination of outages or shorter outage times for customers. The unitized switches will reduce the need for maintenance and adjustment of the operating mechanism.

Q. Please describe Single Phase Sensors.

A. Single phase sensors are used to monitor loads and detect faults at various points on the distribution system. The sensors act as fault indicators, helping to more accurately identify where the outage exists on the circuit. The sensors will provide line loading data to the ADMS system in real time to identify loading conditions associated with overload and phase imbalance. The sensors can also measure conductor temperature for potential future dynamic line rating applications. The data from these devices provides planning engineers with information which allows for reconfiguration of the system due to imbalance or loading concerns, which will enhance overall reliability for customers.

Q. Please describe Voltage Regulator Controls.

A. The new voltage regulator controls will monitor, regulate and optimize voltage on the circuit in a VVO scheme, maintaining "first and last" customer voltage levels within industry requirements. By monitoring and controlling load tap changers, voltage regulators, and capacitor banks, the distribution system can be optimized to reduce line losses while maintaining first and last customer voltage levels within standards. By lowering the voltage profile throughout the circuit while maintaining voltages within standard, customers' consumption will decrease.

Q. How did you determine the number of devices to deploy as part of the DA Project?

A. We reviewed outage data from the past five years to prioritize feeders by frequency and duration of interruptions, along with number of customers impacted. We then modeled the expected impacts to system interruption figures based on scenarios of deployment of DA devices at varying levels of customer segmentation. Finally, we did a cost-benefit analysis to weigh device costs against projected customer benefits to arrive at an optimized approach for the proposed DA deployment.

Q. What are the expected impacts to the system interruption metrics, as calculated as part of the DMP?

A. Based on the cost-benefit analysis and planned deployments of ADMS, Advanced Metering Infrastructure ("AMI"), and DA devices, DP&L expects at least 30%

improvement in the System Average Interruption Duration Index ("SAIDI"), which is the average outage duration for each customer served by DP&L, within the DMP timeline. Based on this same analysis and optimization, DP&L expects at least 35% improvement in the System Average Interruption Frequency Index ("SAIFI"), a measure of the average number of service interruptions a customer experiences, within the DMP timeline. These projected performance improvement percentages are calculated relative to baseline performance metrics, which represent averages from the past five years under a system that does not employ AMI. Additionally, the volume and accuracy of DP&L's system interruption metrics collected through the use of AMI will exceed what is possible today. As a result, baseline performance metrics could vary from those which are available in the future based on the amount of data available and the frequency with which it can be collected. In summary, DP&L projects that with the DMP, customers will experience a 30% reduction in the duration of outages and a 35% reduction in the frequency of outages.

Q. What is the expected impact to the Customer Average Interruption Duration Index?

A. The Customer Average Interruption Duration Index ("CAIDI") is a measure of the average outage duration any impacted customer would experience, or in other words, average restoration time. As a consequence of optimizing the reduction in both SAIFI and SAIDI in DP&L's territory, DP&L's CAIDI is expected to increase. As DA devices are deployed on feeders and SAIFI and SAIDI improve, a smaller subset of customers will be impacted by a given service outage or interruption than occurs currently. Thus, the CAIDI metric calculation regarding the average time to restore service to that subset of customers would be spread over a smaller subset of customers versus a larger subset of its customers today that would be impacted by an outage. DP&L believes that fewer of its customers losing service (SAIFI) for an aggregate average reduction in outage time (SAIDI) are the appropriate metrics to measure the benefits of DP&L's DMP given that the methodology used to calculate CAIDI in the industry fails to account for outage isolation on its feeders.

B. SUBSTATION AUTOMATION

Q. Please describe the Substation Automation project.

A. Effective implementation of SA technology requires upgraded relay protection and communication systems in substations to enable fault isolation and load redistribution. Specific technology and infrastructure required to fully automate a substation will include digital relays and communication gateways.

Q. Please describe Digital Relays.

A. A relay is a device that senses a change in the electrical system (e.g., electrical faults) and sets in motion various protection devices to isolate the fault area from the rest of the electrical system. Digital relays are quick to operate and can be programmed to respond to a variety of field conditions. To fully enable smart grid technologies, existing electromechanical relays need to be replaced with digital, programmable relays, and the associated relay schemes. Digital relays store event data that can be accessed to aid in the diagnosis of circuit problems. Digital relays are more reliable because they are electronic and do not rely on mechanical components to operate. As such, the digital relays do not require on-going calibration and can be adjusted remotely, via secure communications, for changing field conditions.

Q. Please describe Communication Gateways.

A. Substation communication gateways are devices used to collect and transmit metering, status, event, and fault report data from intelligent substation devices. These gateways will be installed at various substations to facilitate secure communications with the planned ADMS system along with supporting other critical functions such as security monitoring. The substation communication gateways also function as the substation remote terminal unit ("RTU") or communicate to the substation RTU for supporting data flow to the ADMS and other support systems.

C. BENEFITS OF DA/SA

Q. What are the expected benefits associated with the DA and SA projects?

A. Expected benefits from DA and SA implementation include incremental reduction in line losses and significant improvements in system reliability and customer service. The DA and SA infrastructure is expected to enhance both operational performance and customer experience by allowing DP&L to:

i. Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem;

ii. Enable DERs and demand response loads to be integrated into operations;

iii. Detect and address emerging problems on the system before they affect service;

iv. Improve reliability and resiliency; and

v. Provide system operators with advanced visualization tools to enhance their ability to oversee, manage, and troubleshoot the system.

Q. When does DP&L expect work on the DA/SA projects to begin and to be completed?

A. DP&L expects to begin implementation of the SA project in the first year following Commission's approval of the DMP and finish implementation over a period of seven years. Implementation of the DA Project is expected to begin in the third year following the Commission's approval of the DMP, in alignment with the conclusion of the ADMS implementation, and finish implementation during year seven of the project.

Q. What investments does DP&L anticipate making to implement the DA/SA project?

A. **Workpapers WP-2.1** and **WP-2.2** contain the year-by-year breakdown of DA/SA costs. The capital costs include hardware, software, and implementation labor. The O&M costs include the ongoing maintenance of the system within a period of 20 years from the start of the DMP to support the operation of the associated infrastructure and systems. DP&L has captured the essential business processes and configuration requirements resulting in a DA/SA estimate that is appropriate for the level of functionality that will be provided. The DA cost per feeder was benchmarked against other utilities across the country, and DP&L's cost estimate fell within the range of the average cost per feeder.

IV. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

Q. What is included in the scope of the ADMS?

A. The ADMS combines, on a single platform, the functionality of an Outage Management System ("OMS") and DMS with the information from a D-SCADA system and other field operations systems (e.g., DA and SA). The ADMS offers modernized capabilities for managing the distribution system through a centralized platform, which can be used to monitor and control new field devices to be installed on the distribution system.

Q. What is the purpose of an ADMS and why is it needed to support the DMP?

A. The ADMS is an enabling technology that provides a wealth of data on distribution system status and loading, and provides the basis for load forecasting. Resulting from DP&L's DMP implementation, the number of data points being managed by the new ADMS will dramatically increase over what currently in DP&L's T-SCADA system. Today, DP&L monitors fewer than 15,000 data points through its T-SCADA system; however, the ADMS will communicate with an estimated 80,000 data points once the DMP has been implemented.

Q. Which systems will interface with the ADMS?

A. Coupling AMI information stored within the Meter Data Management System ("MDMS") with GIS, D-SCADA, OMS, and eventually SA and DA inputs will be critical to enable the full range of potential capabilities of the ADMS.

Q. What operational benefits will be realized by integrating the ADMS and D-SCADA systems?

A. The integration of ADMS and D-SCADA at DP&L will also provide the following benefits:

i. A single, up-to-date network model used for analysis to increase operator efficiency;

ii. Simplified data engineering via coordination of D-SCADA point and GIS data changes;

iii. Improved operations by close integration of ADMS applications with D-SCADA leading to shorter outage times; and

iv. Tools to minimize the number of customers affected by an outage.

These operational benefits will also lead to a better customer experience through the minimization of both the frequency and duration of outages. This also results in quantifiable benefits for customers as explained by Witness Hulsebosch.

Q. What is an OMS and why is this included in the scope of the ADMS deployment?

A. An OMS provides tools and information to restore power to DP&L customers efficiently. For DP&L to maximize the benefits of implementing an AMI system, we will need to replace the legacy OMS with a more flexible and robust system. The current OMS accepts Integrated Voice Response ("IVR") information and actual customer contact information for the generation of outage events. However, a new OMS is needed to incorporate the additional data, such as outage alarms, restoration alarms, and low-and high-voltage alarms generated in near real-time from the AMI system. The new OMS will receive and process various inputs for outage analysis, outage location prediction, crew management, as well as permit dynamic circuit model changes along with maintaining historical data. DP&L's current outage system was not designed or built for many of these advanced features.

Q. Why is a more robust OMS required to support the DMP?

A. A robust OMS is needed to manage the large amount of information generated from multiple diverse sources and to facilitate the efficient transfer of information concerning network status changes. The OMS will provide several operational layers that perform essential tasks related to outage detection, analysis, diagnosis, and restoration. Specifically, the OMS will be able to identify and evaluate various input types by reconciling the divergent system, subsystem, and endpoint sources. Further, the OMS will be able to diagnose the most likely source(s) of an outage and then transfer this knowledge to efficiently utilize DP&L's available restoration resources.

An important objective of DP&L's DMP is to improve network reliability by evaluating power outage data in real time from sources such as AMI, DA, SA, D-SCADA, and IVR, and then use this data to pinpoint power outages more rapidly and shorten restoration time.

Q. Why is it important for the ADMS to interface with GIS and AMI systems to support OMS functionality?

A. DP&L's GIS and AMI systems will provide the additional customer status and location information necessary to advance OMS capability beyond the system inputs of our current Trouble Call Management System ("TCMS") and T-SCADA system. While these traditional methods of obtaining outage information are certainly valuable, they do not provide sufficient detail (e.g., customer to transformer connectivity) or the geographic visibility necessary to deploy work crews in the most efficient manner. The addition of real-time outage information originating from AMI meters, coupled with the customer's location provides the missing ingredients for efficient outage response, particularly during the occurrence of major outage events.

Q. Please explain DP&L's plan for implementing the ADMS Project.

A. DP&L plans to implement a packaged, integrated DMS/OMS software solution over a three-year period. OMS functionality will be implemented first, followed by DMS functionality, since DMS performance is heavily reliant on the availability of the OMS and accurate geospatial data. A comprehensive, formal RFP process will be followed to evaluate and select the OMS/DMS system that will best meet DP&L's current and future operating requirements. A project team consisting of both internal DP&L resources and external consultants with experience specific to OMS/DMS implementations will be selected to develop and execute a project plan that will follow the standard system development lifecycle (analyze, design, build, test, deploy) methodology employed by DP&L for these types of projects. Business processes will be created or re-designed to minimize system customizations and maximize the significant new functionality available in the new OMS/DMS system. A project manager will be used to manage project goals, timeline, budget, and risk. Critical success factors will be established to measure continually the success of the project and to ensure that it is meeting DP&L's objectives. Additionally, the ADMS project includes support for modeling distribution substations in GIS and importing one-line diagrams from GIS for use in D-SCADA and ADMS.

Q. When does DP&L expect work on the ADMS Project to begin and to be completed?

A. DP&L expects to begin implementation of the ADMS project soon after the Commission's approval of the DMP and finish implementation over a period of three years.

Q. What investments does DP&L anticipate making to implement the ADMS Project?

A. **Workpaper WP-2.3** contains the year-by-year breakdown of ADMS costs. The capital cost includes the hardware, software, and implementation labor. O&M costs include the ongoing maintenance of the system within a period of 20 years from the start of the DMP to support the operation of the associated infrastructure and systems. DP&L has captured the essential business processes and configuration requirements resulting in an estimate that is appropriate for the level of functionality that will be provided.

Q. Will integrating the ADMS and OMS improve DP&L's ability to process information?

A. Yes. The following ADMS/OMS capabilities will allow DP&L to process information through all stages of an outage:

i. Capture and store meter events and alarms created by the AMI system;

ii. Display the location of meter-related events and alarms on an electronic map;

iii. Associate meter events with specific isolation and sectionalizing equipment within the DP&L distribution system;

iv. Provide automated grouping of both IVR and AMI related inputs to predict outage locations along with probable source and isolation/sectionalizing equipment;

v. Provide outage updates to customers throughout a service outage event;

vi. Provide automated restoration confirmation to affected customers upon re-energizing sectionalizing equipment for restoration purposes; and

vii. Provide automated reliability index reporting based upon actual outage and restoration times.

Q. What are the operational efficiency benefits associated with an ADMS?

A. Implementing an ADMS at DP&L will enable the Company to more efficiently:

i. Perform system analysis;

ii. Plan daily operations;

iii. Manage planned events;

iv. Provide faster restoration following unplanned events;

v. Optimize the distribution system;

vi. Monitor equipment condition; and

vii. Balance feeder load.

The ability to analyze near real-time or actual distribution load data obtained by AMI meters and stored in the MDMS can generate savings. These savings occur through a reduction of system technical losses and a reduction in future capital expenditures for distribution infrastructure, through right-sizing of conductors, substation and distribution transformers, and appropriate timing for circuit/substation upgrades due to load growth.

Q. What are the overall customer benefits associated with an ADMS?

A. As an enabling technology, an ADMS will provide increased visibility of the grid through real time information and mapping, outage analysis and prediction, load shedding, and reduced restoration time, all of which benefit the customer. Specifically, an ADMS can manage fault detection, isolation, and recovery and Volt/VAR control while interfacing with other systems. While many of the customer benefits facilitated by the ADMS are captured within workpapers for individual technologies (e.g., Distribution/Substation Automation, Conservation Voltage Reduction), an ADMS ties many of these investments together to generate customer benefits.

Furthermore, as technologies mature and DERs approach parity with traditional generation sources, customers are installing rooftop solar, EVs, and other grid-connected devices that DP&L must accommodate. As policies that increase reliability and renewable energy penetration are implemented, an ADMS will facilitate proper siting and approval processes for these customer-installed DERs while maintaining reliable service for the customer and appropriately leveraging the capabilities of these DERs.

Q. Will any of the information collected by the ADMS be provided to third parties similar to how metering data is shared through the CRES portal today?

A. DP&L understands that the current market paradigm that distribution utilities operate under will change. DP&L expects the distribution system to operate in a manner that is analogous to the transmission grid. Under this scenario, DP&L will publish information through a portal that third parties will utilize to provide services to customers and to DP&L. The ADMS will be the system used internally to collect the data and push it towards the third-party portal. Thus, DP&L will become a market enabler and will operate the collection of OT systems in a grid-as-a-platform environment.

Q. What investment does DP&L anticipate making to implement a portal to provide this data to third parties?

A. As shown on line 8 in **Workpaper WP-3.2 Customer ePortal / Mobile App**, DP&L has allocated $4.5 million in capital costs, in nominal dollars, to design and deploy this portal to be able to share this information with third parties. DP&L is viewing this as an extension of the existing CRES portal, which is supported by Witness Tatham.

V. CONSERVATION VOLTAGE REDUCTION (CVR) AND VOLT/VAR OPTIMIZATION (VVO)

Q. What is the purpose and operational benefits of CVR/VVO?

A. CVR and VVO enable DP&L to consistently provide customer voltages in the lower end of the acceptable range with the goal of achieving energy and demand reductions for customers. The addition of controlled capacitor banks and voltage regulators, through this CVR/VVO initiative, will result in an improved power factor. These technologies will also increase overall system efficiency through a more consistent voltage profile across the entire circuit and ultimately reduce line losses. In addition, voltage can be reduced via controls, maintaining a consistent first to last customer voltage across the circuit and lowering energy consumption at the meter. Voltage levels, while reduced in select areas, will continue to meet or exceed the industry-required range to provide consistent quality service to the customer. This reduced voltage level will lead to lower consumption for customers.

Q. Does DP&L currently have any CVR/VVO deployed on its system at this time?

A. No, DP&L does not have a CVR/VVO system installed on the distribution system today, although the company does have the ability at select substations to implement a 5% voltage reduction if directed by PJM.

Q. When does DP&L expect work on the CVR/VVO project to begin and to be completed?

A. DP&L expects to begin implementation of CVR/VVO in year six—following the Commission's approval of the DMP—as a "Phase 2" to the ADMS project. CVR/VVO implementation is expected to last five years.

Q. What investments does DP&L anticipate making to implement CVR/VVO?

A. **Workpaper WP-2.4** has the year-by-year breakdown of CVR/VVO costs. The capital costs include the hardware (including capacitor banks and controls), software, and implementation labor. O&M costs include the ongoing maintenance of CVR/VVO software within a period of 20 years from the start of the DMP.

Q. What are the overall customer benefits associated with an VVO?

A. Customers will see reduced consumption when the VVO system is implemented. By maintaining a narrower voltage profile, across the circuit, customer equipment is subjected to less variability to their voltage profile. As a result, customers will see reduced consumption, which has the potential to reduce customer bills.

VI. GEOGRAPHIC INFORMATION SYSTEM (GIS)

Q. Please describe the GIS project.

A. The current ESRI GIS system is a geo-spatial system that shows the location of existing transmission and distribution assets, including poles, wires, transformers, etc. in the field. Planned activities relative to the DMP for the existing GIS include performing a system-wide field inventory to identify electrical connectivity to the individual customer level, which is a requirement to support the implementation of an OMS. The current system does not provide information showing customer to individual transformer connectivity. To provide the data required for an ADMS to function properly and to utilize AMI data to predict outages, this level of detail is needed. Additionally, the GIS project will include implementation of steady-state processes for continuous tracking of field asset deployments. This combined effort will allow the system to more accurately reflect the current state and location of all distribution assets.

Q. When does DP&L expect work on the GIS project to begin and to be completed?

A. DP&L expects to begin implementation of the GIS solution updates in the first year following the Commission's approval of the DMP and finish implementation over a period of two years.

Q. What investments does DP&L anticipate making to implement the GIS Project?

A. **Workpaper WP-2.6** has the year-by-year breakdown of GIS costs. The capital costs represent updates to the existing GIS system and the asset data captured within it. O&M costs include the ongoing maintenance of GIS software within a period of 20 years from the start of the DMP. DP&L has captured the essential business processes and configuration requirements resulting in an estimate that is appropriate for the level of functionality that will be provided.

VII. MOBILE WORKFORCE MANAGEMENT SYSTEM (MWFM)

Q. Please describe the MWFM project.

A. Implementing AMI will benefit DP&L's customers by decreasing meter-related field service order activity such as reading verifications, read and leave-on service orders, and disconnect-reconnect orders; however, to maximize the benefits from the OMS and remaining field service order staffing, DP&L needs to implement a new MWFM. While the existing system provides a level of efficiency for distributing and collecting field service orders generated by CIS, but it does not allow real-time dispatching of priority service orders, service order completion, or generation/dispatch of outage related trouble or service orders. A modern MWFM would enable these functionalities which are not currently available through the existing system.

Q. Please explain DP&L's plan for implementing the MWFM Project.

A. DP&L plans to implement a MWFM software solution over a two-year period. A comprehensive, formal RFP process will be followed to evaluate and select the MWFM system that will best meet DP&L's current and future operating requirements. A project team consisting of both internal DP&L resources and external consultants with experience specific to MWFM implementations will be selected to develop and execute a project plan that will follow the standard system development lifecycle (analyze, design, build, test, deploy) methodology employed by DP&L for these types of projects. Business processes will be created or re-designed to minimize system customizations and maximize the significant new functionality available in the new MWFM system. A project manager will be used to manage project goals, timeline, budget, and risk. Critical success factors will be established to measure continually the success of the project and to ensure that it is meeting DP&L's objectives.

Q. What benefits can be expected from the implementation of a MWFM system?

A. Implementing a new MWFM system will provide DP&L's customers significant benefits by improving the timeliness with which service disruptions are resolved and by decreasing meter-related field service order activity such as reading verifications, read-only service orders, and disconnect-reconnect orders. A new MWFM will:

i. Provide automated resource allocation and least-cost travel routing based upon vehicles, staff, and equipment location and availability;
ii. Provide in-field order initialization and automated order completion within CIS;
iii. Provide DP&L Call Center staff with real-time service order status information;
iv. Coordinate meter-removal service orders with AMI systems to prevent false outage signals; and
v. Generate and dispatch outage orders created by the OMS, and collect real-time outage data from field crews, which can be communicated to customers during a service disruption or other event.

Q. When does DP&L expect work on the MWFM Project to begin and to be completed?

A. DP&L expects to begin implementation of the MWFM in year four after the Commission's approval of the DMP and finish implementation over a period of two years. There is cost associated in the first year that pertains to deployment of field equipment for technicians such as tablets and laptops. This is done to coincide with GIS deployment and the field audit.

Q. What investments does DP&L anticipate making to implement the MWFM Project?

A. **Workpaper WP-2.7** has the year-by-year breakdown of MWFM costs. The capital costs include the hardware, software and labor required to implement and deliver a new MWFM system. The cost of field devices is incurred in the first year of the plan, corresponding with GIS system upgrades. O&M costs include the ongoing maintenance of the system within a period of 20 years from the start of the DMP. DP&L has captured the essential business processes and configuration requirements resulting in a MWFM estimate that is appropriate for the level of functionality that will be provided.

VIII. TELECOMMUNICATIONS INFRASTRUCTURE

Q. Please describe DP&L's existing Telecommunications infrastructure.

A. DP&L currently owns and operates a robust and extensive integrated communication network, which was developed based on the research, development and engineering that led to the investment in this flexible foundation that will support the overall integration to the grid. These developmental costs are included in the Grid Modernization R&D asset that Witness Hall discusses. Those assets include:

i. A private, territory-wide, digital 800 MHz Land Mobile Radio ("LMR") system used for voice dispatch of DP&L's workforce and for some limited DA communications. This system is planned to be used for broader data communication needs, including dispatching and more robust machine-to-machine "M2M" communications for DA.

ii. An IP-based microwave radio network that consists of approximately fifty (50) sites to bring broadband connectivity to key locations in the DP&L service territory. The current iteration of this system provides for 300 Mbps of bandwidth to each location. This infrastructure will be used for AMI communications as well as providing connectivity to substations not currently connected to the microwave network.

iii. A fiber optic communication network connecting approximately 50 substations throughout the Dayton metropolitan area. This network is built to provide direct communication links for protective relaying between substations, interconnect key operating centers and offices, and provide general substation communications. This network also interconnects with the DP&L microwave network at various locations.

iv. A 900 MHz narrowband multiple-address radio system for collecting substation data and controlling substation devices via the T-SCADA system in the more rural parts of the DP&L service territory. This system is approaching end of life which, as part of this DMP, is set to be replaced with a wireless broadband system that will increase bandwidth and provide IP connectivity for SA and DA efforts.

v. The microwave and fiber networks are interconnected utilizing Multi-Protocol Label Switching ("MPLS") technology that allows for the logical separation of data streams; supporting the wide array of traffic types utilizing the communication network. DP&L primarily utilizes the networks to transport T-SCADA data as well as the voice traffic from the LMR system. Several other data flows are also incorporated into the network. The network also provides connectivity to back-up locations in the event a disaster takes down the primary control or data center. As these systems have been upgraded or replaced in the recent past, they have been designed and built with the vision to support future utility applications, including smart grid applications, and with a view towards providing strong cyber-security controls.

Q. Please describe the need for Telecommunications investment.

A. DP&L's previous investment in its communication network continues to serve the communication needs of the company at the sites originally deployed, and the Company plans to continue to use that equipment. To carry out the DMP deployment across its entire service territory, DP&L will need to design and install additional telecommunications infrastructure at sites where no existing communications exist. DP&L envisions that it will use the existing tower infrastructure to implement Point-to-Point ("PTP") microwave radios links between the current towers and the remaining substations not served by either the fiber optic or microwave networks today. Additionally, a Field Area Network ("FAN") will be deployed providing connectivity to the DA equipment that is being called for in the DMP.

Each of these deployments would also include the deployment of an Internet Protocol/Multi-Protocol Label Switching ("IP/MPLS") router and a firewall to deliver the advanced IP/MPLS segmented and secure services for the DMP system components. This deployment is specifically called for to support the DA and SA projects; it provides two-way communication links between the technology systems and the field equipment. Furthermore, it will support current and future cyber-security requirements as needed.

These different communications networks have software management systems, which are individually referred to as Element Management Systems ("EMS"). To efficiently monitor, manage and control these telecommunication systems and to meet the reliability requirements of the business applications, a centralized Network Operating Center ("NOC") must be developed. This centralized system consists of a core Network Management System ("NMS"), also known as a Manager of Managers ("MOM"). The MOM will centralize all the individual Energy Management Systems ("EMS") from the existing and new communications systems, into a "single pane of glass" dashboard to streamline operations for the telecom team.

This MOM will centralize events and, through event correlation, assist the DP&L telecom team in determining root causes of alarms or outages to allow for faster dispatch and a shorter mean time to repair. Additionally, this system will be tied to event, incident and trouble ticketing as well as the MWFM to efficiently dispatch technicians.

Historical trending analytics in the MOM will also assist in telecom asset management and preventive maintenance, which will help reduce outage and connectivity gaps to the smart grid components and grid control devices that are part of the DMP.

The specifics of this system will be determined during requirements gathering, technology and vendor selection during the planning stage and initially implemented as part of the telecommunication expansion in the first year of the plan prior to new devices coming online.

Q. When does DP&L expect work on the Telecommunications project to begin and to be completed?

A. DP&L expects to begin implementation of the Telecommunications project in first year following the Commission's approval of the DMP, and finish implementation over a period of seven years.

Q. What benefits can be expected from the implementation of a Telecommunications system?

A. The telecommunication infrastructure will allow for the flow of information between field devices and the ADMS system – which allows for better information flow to our customers during outage events and provides for monitoring of equipment installed on the distribution system such as DERs. The information flowing to the ADMS from the field devices will allow for dispatchers, and field crews, to pinpoint the location of the fault and quickly resolve the outage. This information will also be used to inform customers of outages and restoration times through the portal and/or mobile application as described by Witness Tatham.

IX. WORKPAPERS

Q. Please describe the process that you used to calculate the figures shown on the Workpapers corresponding to the sections included as part of this testimony.

A. The DP&L team in partnership with external consultants collected information from vendors and internal resources to arrive at cost estimates. The blended consulting / DP&L team, working together to provide the estimate for these systems based on RFP results and other external vendor quotes. Included in the team were subject matter experts knowledgeable in each of the areas that would be affected by the systems. The team defined high level system requirements and contacted vendors for some of the areas where the team might not have robust cost estimates. Vendor responses were averaged to arrive at the implementation and ongoing maintenance estimates shown in the corresponding workpapers. In addition, cost estimates were benchmarked against other utility grid modernization filings to ensure accuracy. For example, DP&L's DA cost per circuit was found to be on the lower end of the benchmark compared.

Q. What is shown on these Workpapers?

A. The associated Workpapers depict the Capital and O&M costs for a twenty-year period. Capital costs include the solution implementation costs, hardware purchases, software purchases and other relevant capital cost that are described in the Workpapers. O&M costs include hardware maintenance, software maintenance, and maintenance labor associated with the ongoing support of the related technology or system.

Q. In Workpapers, under "Summary of *[Project]* Capital Costs," how are "Solution Implementation Costs" calculated?

A. Solution Implementation Costs under the Capital Costs heading for each system comprises capitalized labor costs that represent the labor required to implement a project investment. Capitalized labor costs are calculated by applying a blended labor rate to the estimated number of days required to implement the given technology. The number of estimated work days to implement the system is estimated based on analysis of the specific business requirements and specific vendor experience implementing that technology.

Q. In the associated Workpapers, under "Summary of *[Project]* Capital Costs," how are "Hardware Purchases" calculated?

A. Hardware purchases to support each of the project system implementations include components such as servers, hubs, routers, work stations, printers, storage, etc. for production, development and disaster recovery environments. The hardware purchases figures were driven by the IT department philosophy of standardization of platforms, open systems, and open standards. Industry best practices were used to ensure that the servers and storage estimates ensured adequate growth capability.

Q. In the associated Workpapers, under "Summary of *[Project]* Capital Costs," how are "Software Purchases" calculated?

A. Software purchases to support each of the project system implementations include application and database software licenses and ancillary end user data query tools. The software purchases figures used for our Capital Cost Summary are vendor-neutral and represent a blended cost of reputable industry-established software packages.

Q. In the associated Workpapers, under "Summary of *[Project]* O&M Costs," how is "Hardware Maintenance" calculated?

A. Hardware Maintenance includes the fees payable to the hardware vendor to provide maintenance and support needed to maintain the servers and storage systems. Hardware maintenance is calculated as 5%-10% of the Hardware Purchases Costs. This is a widely recognized standard amount charged by hardware vendors.

Q. In the associated Workpapers, under "Summary of *[Project]* O&M Costs," how is "Software Maintenance" calculated?

A. Software Maintenance includes the fees payable to the software company to provide maintenance and support needed to maintain current system functionality. Software maintenance is calculated as 10%-20% of the Software Purchases Costs. This range is a widely-recognized standard amount charged by software vendors for ongoing maintenance and routine software support of licensed vendor software.

Q. In the associated Workpapers, under "Summary of *[Project]* O&M Costs," how is "Maintenance Labor" calculated?

A. Maintenance Labor includes the incremental DP&L labor costs needed to maintain a particular system or technology. The calculations for maintenance labor were based on a fully-loaded hourly rate multiplied by the number of FTEs required to support the investment. This total number of additional resources is necessary to support the increase in OT infrastructure, databases and associated equipment, and to provide ongoing application support.

X. CONCLUSION

Q. Please summarize your testimony.

A. In summary, the technology and infrastructure that DP&L proposes to implement as part of the DMP will enable its customers to receive near-term benefits. Working together, the proposed investments make it possible for DP&L to take advantage of the improved outage detection and restoration capabilities available in today's mature OMS/DMS systems. Furthermore, they will enable distribution operations personnel to sense, monitor, and analyze information from many data sources at various levels of system granularity, which will allow system planners to utilize this information to optimize use of DP&L's assets. The MWFM will improve communications between the field technicians and the office support staff to deliver improved customer service, optimization of technician time and reduction of windshield time. Investment in telecommunication serves as a foundation for all these benefits to be realized.

Q. Does this conclude your direct testimony?

A. Yes.