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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO
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BOOK II – Customer Conservation and Energy Management Programs

CHAPTERS, SCHEDULES AND WORKPAPERS

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

Chapter 1
Executive Summary
of
The Dayton Power & Light Company Customer Conservation and Energy Management Programs

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1 Introduction to DP&L's Customer Conservation and Energy Management Programs

1.1 Vision of Customer Conservation and Energy Management

The Dayton Power and Light Company ("DP&L" or "Company") remains focused on providing customers with safe, low-cost, reliable electric service, and through this Customer Conservation and Energy Management ("CCEM") filing is seeking approval to recover the required funding to develop its infrastructure, offerings, and operations. DP&L needs to take these steps in order to serve its customers better by: (1) providing them with tools to control their energy expenditures, (2) reducing environmental impact, (3) improving the efficiency of the distribution system, and (4) increasing the reliability of service provided to customers. The Company's plan for CCEM and the investments needed to achieve it are necessary to continue to meet the needs of its customers and to comply with Ohio law contained in Am. Sub. S.B. 221, signed into law by Governor Strickland on the 1st of May 2008. DP&L's program includes energy efficiency and demand response options, the supporting infrastructure which is needed for them to function and be effective, and state-of-the-art network automation technologies.

In this application the Company will lay out the specifications, benefits, and costs for the various components of the program separately. In reality, however, they all go together and all are necessary in order to make customers more informed, to enable customers to choose among options to tailor and control their utility service, to continue to provide customers with low-cost and reliable electric service and to meet the targets contained in S.B. 221.

The Company's CCEM vision is a technologically-advanced, modern distribution system allowing customers to manage their energy consumption and enabling DP&L to deliver that energy reliably and efficiently utilizing real-time, automated controls. DP&L's plan for CCEM is a fully-networked system that includes Automated Metering Infrastructure ("AMI"), energy efficiency ("EE") and demand response ("DR") programs, and distribution and substation automation. This integrated system will be capable of monitoring and communicating grid status and the impact of consumption decisions to automated decision-making systems. It will allow

DP&L to deliver energy more efficiently while providing customers with valuable information for better decision making on how and when to use energy.

The AMI infrastructure is the foundation for efficiency and demand response programs which give customers the ability to control their energy usage; but to capture the benefits of AMI there must also be modern telecommunications and information technology systems. Lower cost to customers depends on a modernized delivery infrastructure including investments in smart grid technologies.

DP&L's CCEM programs will provide tangible and intangible benefits to all customers and the community. It will bring environmental benefits today, as well as to future generations. Customers will have options and choices when it comes to the amount and type of power they purchase, and when to use those energy resources. DP&L's distribution system will be more reliable. The Company will experience lower line losses and customers will use less electricity, both of which should create a reduced need for building additional capacity. Utility operating costs will be lower as a result of automation and better visibility into operational aspects of the grid, leading to more efficient and effective use of resources and lower costs to customers.

1.2 Customer Conservation and Energy Management Road Map

This Application proposes a seven-year roadmap to establish the building blocks of the CCEM programs. The three fundamental building blocks of DP&L's CCEM programs are:

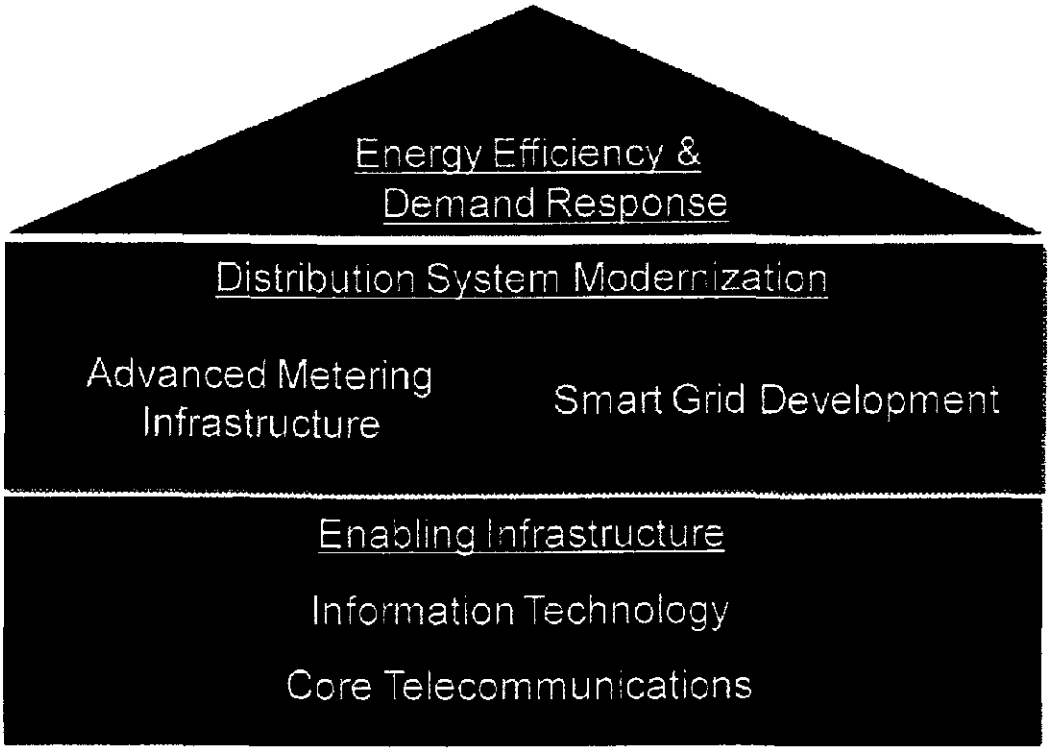
1. **Energy Efficiency & Demand Response.** Establishment of a robust set of energy efficiency and demand response programs targeted toward giving customers the ability to control their own energy usage and expenditures.
2. **Delivery System Modernization.** Building an Advanced Metering Infrastructure and developing key elements of the smart grid such as distribution and substation automation.
3. **Enabling Infrastructure.** Addressing gaps in DP&L's existing information technology and telecommunications infrastructure to be able to support and realize the full potential of both advanced metering and smart grid functionality.

Exhibit 1.2 summarizes the components of DP&L's CCEM programs.

Customers will experience immediate benefits of energy efficiency programs and substation control (part of smart grid development). As meters are swapped out, customers will be eligible for demand response programs and will realize reliability benefits. By the end of the seven-year program, DP&L will have replaced 100% of meters and all customers will have access to demand response programs. Sixteen percent of circuits and 34% of substations will be automated by the end of the seven years.

To complete the CCEM programs the Company intends to launch a second phase in 2016 which will consist primarily of the full-scale implementation of smart grid components.

Exhibit 1.2 Components of DP&L's Customer Conservation and Energy Management (CCEM) Programs



2 Overview of CCEM Programs

2.1 Energy Efficiency & Demand Response

2.1.1 Objective

The Company's Energy Efficiency and Demand Response Plan represents a commitment by DP&L to enhance customers' energy value through implementation of a robust and flexible portfolio of energy efficiency and demand response solutions.

Table 2.1 summarizes the impact on energy and demand of these programs over the next 7 years, as well as the costs DP&L will incur to achieve that impact. In sum, the Company estimates that it will achieve a total reduction, by year 7, of 2,475 GWh of energy and of 178 MW of demand from energy efficiency and demand response programs.

Programs will be voluntary. Customers who choose to participate will gain the ability to exercise more control over their energy usage and expenditures.

2.1.2 Executive Summary of Energy Efficiency & Demand Response Plan

DP&L's Energy Efficiency and Demand Response programs are tailored to meet the needs of all customer segments. Therefore, customers will gain immediate access to such benefits as in-store discounts for high efficiency lighting and rebates for high efficiency commercial and industrial equipment. DP&L plans to launch most programs in January of 2009. Other programs cannot begin until underlying infrastructure such as AMI meters and select IT systems are in place. Those programs will be made available to customers as soon as the necessary infrastructure is operational. See Exhibit 4.1 for a detailed deployment schedule. The Plan has three primary elements.

1. ***Residential Portfolio of Programs.*** The residential portfolio of programs offers customers multiple opportunities to better control their energy usage and costs while promoting comprehensive actions that can create the most value for customers. Specific program elements include:

- **Residential Lighting.** This program will initially focus on buying down the cost of compact fluorescent light bulbs ("CFL") sold at the retail level. Over time, DP&L may expand this program to include energy-efficient fixtures as well as other types of efficient lighting.
- **Residential Heating, Ventilation and Air Conditioning ("HVAC") Diagnostics & Tune-Up.** Under this program HVAC technicians are trained in proper refrigerant charge and airflow techniques, and customers are offered incentives to have their residential HVAC units tuned up.
- **Residential HVAC Rebates.** This program provides rebates to customers who purchase new energy-efficient HVAC units.
- **Residential Appliance Recycling.** This program provides customers with an incentive payment and free removal of an inefficient window air conditioner, refrigerator or freezer.
- **Residential Appliance Rebates.** This program provides rebates to customers that purchase qualifying Energy Star freezers, dishwashers, room air conditioning units, dehumidifiers and ceiling fans.
- **Residential Low Income.** DP&L will fund energy audits for low-income customers. Recommendations from the audit that are found to have a benefit-to-cost ratio better than 1.0 will be directly funded and implemented through this program.
- **Residential Direct Load Control.** DP&L will offer customers a programmable thermostat installed at no cost in exchange for allowing DP&L to signal the central air conditioning unit to cycle on and off during peak periods.
- **Residential Time-of-Use Pricing.** A voluntary time-of-use pricing option will be made available to residential customers once sufficient infrastructure is in place. This tariff will feature a lower rate during off-peak hours and a higher during on-peak

hours. Customers choosing to participate in this pricing option will have the ability to save money by shifting usage to off-peak periods.

- **Residential Peak-Time Rebate Pricing.** Under this pricing option, customers that reduce their energy consumption during peak periods below a pre-established baseline will receive a rebate from DP&L. This service will be offered in 2011 to residential customers who have advanced meter infrastructure in place. Based on the success of this effort, DP&L intends to make the program available to all residential customers with interval meters.
- **Home Energy Displays ("HED").** DP&L will provide customers with home energy displays that will provide information on current energy consumption and prices. The display will also receive and display signals regarding peak and/or critical peak pricing periods. While many customers will choose to get information on energy usage, pricing, and trends from DP&L's website portal available via the Internet, this home energy display will allow customers who do not have Internet access to obtain the same information.

DP&L will also continue to explore opportunities to influence the efficiency of the new housing stock via partnering with home builders and architects; however, given low new home growth at this time, the Company does not plan to launch a broad-scale new construction program. As circumstances change the Company will re-evaluate based on the estimated value proposition to customers from such programs. In the meantime, DP&L plans to pursue small opportunities with existing residential homes to gather energy consumption and premise-performance data that will help us to refine and refresh the overall program portfolio. The Company is evaluating an innovative energy information system that will allow customers to monitor the efficiency of their end-use activities and equipment.

2. ***Non-Residential Portfolio of Programs.*** The portfolio includes a wide variety of individual technology and/or device incentives. Specific program elements include:

- **Non-Residential Prescriptive Incentives.** This program offers incentives for designated commercial and industrial efficiency measures such as improved lighting technologies, efficient motors and drives, and efficient compressed air systems. Incentives will be fixed and paid on a per-measure basis. As the Company gains experience with the program and customer needs, the list of prescribed measures will be revised. All measures for which a prescriptive incentive is offered will have a benefit-to-cost ratio of greater than 1.0.

- **Non-Residential Custom Incentives.** This program offers incentives for more complex measures, including industrial process improvements and new building construction. Any cost-effective measure that improves a customer's electric energy efficiency will be considered for an incentive. Incentive levels will be project-specific and based on prescribed calculations. In order to receive an incentive, a project must have a benefit-to-cost ratio of greater than 1.0.

- **Non-Residential Direct Load Control.** A direct load control program will be made available to small customers whereby customers receive a free programmable thermostat in exchange for allowing DP&L to cycle their central air conditioner during periods of peak demand.

- **Non-Residential Time-of-Use Pricing.** Several time-of-use pricing tariffs will be offered to non-residential customers. The electric rates are higher during peak hours and lower during off-peak hours, and some tariffs will offer a critical peak pricing feature whereby the electric rate during extreme peak hours is significantly higher than the rate during all other hours.

3. ***Education / Awareness / Market Transformation Activities.*** DP&L recognizes the importance of customer education. The Company will implement educational outreach initiatives to build and expand consumer energy management awareness. DP&L plans to launch these programs January 1, 2009. DP&L will use and enhance existing energy education venues and networks such as its website, various customer communications

modalities and school presentations to maximize the public's exposure to these initiatives. The Company will also explore partnering with energy efficiency vendors and channel partners to build an energy efficiency showcase and educational facility.

Although the Company believes, based on best available current information, that this Plan provides the best suite of programs to aid DP&L's customers in achieving energy and demand reductions, DP&L also knows that it is in all parties' best interest that flexibility is maintained to alter the programs as well as add or delete programs over time in response to evolving customer needs, implementation experience, technology development, and market conditions.

Table 2.1.2 Summary of Anticipated Energy Efficiency and Demand Response Program Costs and Savings 2009-2015

	Cumulative O&M Costs ($Millions)	Cumulative Capital Costs ($Millions)	Cumulative Energy (GWh)	2015 Peak Demand (MW)
Residential				
Lighting	20.1	0.0	765	17
HVAC Diagnostic & Tune-Up	8.4	0.0	77	18
HVAC Rebates	11.0	0.0	40	10
Appliance Recycling	2.5	0.0	89	4
Appliance Rebates	1.4	0.0	23	1
Low Income	7.7	0.0	48	1
Direct Load Control	7.1	0.0	15	23
Time of Use Pricing	1.3	0.0	0	6
Peak Time Rebate Pricing	1.3	0.0	0	8
Home Energy Displays	*	*	309	0
Total Residential	**61.0**	**0.0**	**1,367**	**87**
Non-Residential				
Prescriptive Incentives	22.3	0.0	791	60
Custom Incentives	14.0	0.0	314	17
Direct Load Control	1.1	0.0	3	5
Time of Use Pricing	1.3	0.0	0	4
Time of Use with Critical Peak Pricing	1.3	0.0	0	5
Total Commercial	**40.0**	**0.0**	**1,108**	**91**
Community Programs				
Education & Outreach	11.8	0.5	0	0
Total Community Programs	**11.8**	**0.5**	**0**	**0**
EM&V	**5.7**	**0.0**	**0**	**0**
Total Energy Efficiency & Demand Response	**118.4**	**0.5**	**2,475**	**178**

* Home Energy Display costs are captured as part of AMI rollout

2.2 AMI

2.2.1 Objective

Advanced Metering Infrastructure ("AMI") is the foundation for the demand response programs outlined above. It transforms the meter from a simple measuring and counting device, to one element of an integrated system of hardware, software, and meaningful information that

can be used to better manage the electric services. AMI is not simply a tool to capture customer consumption of energy, but a hardware and software architecture capable of capturing consumption, demand, voltage, current and other information on a near-real-time basis. Data can be provided at the customer level and for other enterprise-level systems either on a scheduled basis or on demand. A typical AMI network will communicate this data to a central location, sorting and analyzing it for a variety of purposes such as customer billing, outage response, system loading conditions and demand-side management. The AMI network will also send this information to other systems, customers and third parties, as well as send information back through the network and meters to capture additional data, control equipment, and update the configuration of the equipment and software load.

AMI introduces new functionality that will support utilities in improving operations and providing greater value to customers. The availability of near-real-time consumption data supports time-differentiated rates for customers. Utility representatives will have access to more complete and current customer data when addressing customer concerns. Further, the interval data and accurate load shapes can be made available to customers to help them manage energy costs.

During outages, AMI will make it possible to recognize quickly and accurately service restoration needs, allowing improved crew dispatch, reduce unneeded trips to customers who have already been restored, and improve communications with customers and the community. The AMI system provides the ability to detect outages without customer call-ins.

The proposed AMI system will help to minimize the cost of energy by permitting customers to access various demand response programs that improve system load factor and help to defer the construction of new generation facilities. AMI is a necessary enabling technology for the success of demand response, because:

- AMI provides the reliable interval data necessary to measure and verify load reductions achieved by customers, individually and as groups.
- AMI provides information necessary for customers, individually and as groups, to determine the impact on their own actual load of specific demand response actions

they might take.

- AMI provides a platform to engage customers in demand response. Time-based pricing programs can be tailored carefully and precisely with AMI. Customers can be notified when demand response would save them the most money. Prices and financial incentives can target specific outcomes (e.g., peak load reduction for reliability purposes, reduction of peak energy prices, control of local peak loads that may stress the distribution system).

The utility industry considers the implementation of an AMI system to be the fundamental enabling component of the smart grid. Much of the benefit to implementing a smart grid infrastructure relies on the capture of data detailed enough and timely enough to communicate the status of the utility distribution system to process-intelligent controls for the distribution equipment. Properly utilized, AMI can capture meter-level activities and data for smart grid applications, for example:

- SCADA voltage telemetry data at feeder breakers in the substations can indicate the quality of the power supply to the distribution network, but voltage information at service transformers and customer delivery points is necessary to discern circuit or transformer level problems for more effective Volt/VAR control.
- Substation breaker and reclosure operations can be used to evaluate the large-scale extent of an outage, but meter-level outage and restoration notification events are necessary to optimize outage restoration efforts.

2.2.2 Executive Summary of AMI Plan

The Company believes that there are four primary components necessary for an AMI system configuration.

- ***Meters and Modules.*** The proposed AMI system calls for the replacement of all residential and commercial meters during this seven-year time period with digital electronic meters and meter module combinations that provide full AMI functionality.

- ***Communications Network & Equipment.*** The AMI communications solution includes communications hardware and software and associated system and data management software that create a two-way communications network between AMI meters and utility business systems which allows collection and distribution of information to customers and the utility. This network is necessary for customers and the Company to realize the value of the meters themselves.
- ***Home Energy Displays (HED).*** DP&L's plan includes support for a customer Home Area Network and includes energy display devices that are easily accessible and easy to use that show customers their current energy usage, trends, and current energy prices. DP&L will make energy displays available to customers who do not have Internet access.
- ***IT Systems.*** Effective implementation of AMI technology requires acquisition and implementation of supporting IT systems including a customer information system ("CIS"), meter data management system ("MDMS") and e-Services. These system investments are required to make it possible for DP&L to manage the enhanced operational environment as well as to allow customers to access data and interact with DP&L.

Table 2.2.2.a Total AMI Deployment Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	5,809,402	12,148,452	14,462,527	19,488,035	18,961,517	18,930,040	675,343	90,495,316
Communications	30,011,707	16,775,233	2,551,256	2,500,995	2,356,231	1,128,761	-	55,324,182
Home Energy Displays	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	13,438,485
IT	24,133,196	23,814,338	21,974,828	12,111,736	9,526,633	3,418,843	779,803	95,759,377
Total	59,954,305	54,406,166	41,044,733	37,204,912	34,191,628	26,760,572	1,455,146	255,017,361

source: WPH-1

Table 2.2.2.b Total AMI Deployment O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	506,885	1,284,859	1,819,622	2,124,535	2,286,175	2,444,442	2,097,929	12,564,146
Communications	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,126	1,788,074	10,141,080
Home Energy Displays	-	83,407	186,213	341,420	507,778	671,924	671,924	2,462,667
IT	293,767	1,391,330	4,789,216	7,202,230	7,701,528	8,175,079	8,336,662	37,889,811
Total	1,074,231	3,859,526	8,495,867	11,402,945	12,261,975	13,068,571	12,894,590	63,057,704

source: WPH-1

2.3 Smart Grid Development

2.3.1 Objective

The Company believes that the ultimate impact of a smart grid will be a greatly improved delivery system that improves the efficiency of delivery and enhances reliability. With AMI and robust energy efficiency and demand response programs as a foundation, additional smart grid components will create a digital energy system that will:

- Detect and address emerging problems on the system before they affect service;
- Respond to local and system-wide inputs and have much more information about broader system problems;
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances;
- Automatically adapt protective systems to accommodate changing system conditions;
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem;
- Enable distributed resources to be integrated into operations;
- Improve reliability and security as key factors; and
- Provide system operators with advanced visualization tools to enhance their ability to oversee the system.

2.3.2 Executive Summary of Smart Grid Development

The Company's long-term plan for a smart grid includes a fully network-connected system that communicates grid status and automates transmission and distribution decision-making systems. By means of this application, the Company is proposing to roll out a limited set of technologies and smart grid concepts pertaining to distribution and substation automation. While DP&L expects immediate customer benefits from some of the well-proven concepts such as substation control, the Company also plans to introduce other automation technologies in order to validate how they operate in combination with AMI systems and demand response

programs to achieve operational, reliability, and efficiency benefits.[1] Following this 7-year "development" phase DP&L expects to submit an expanded proposal for full deployment of full-scale smart grid implementation.

The 7-year development plan will focus on implementation of distribution automation technology which requires installation of a series of controls, switches and monitors as well as a supporting communication infrastructure. DP&L plans to automate 4 circuits per year in years 2009 through 2014 and starting in 2015 will begin more aggressive rollout with the automation of between 30 and 50 circuits. Subsequent to this seven-year development phase, the Company expects to continue at the rate of 30 to 50 circuits per year through 2023; however DP&L is only seeking recovery, at this time, for costs incurred through 2015.

In addition, the Company proposes to automate substations by upgrading relay protection and communication systems in substations to enable fault isolation and load redistribution in conjunction with the distribution automation technology being deployed in the development phase. In order to realize the reliability improvements enabled by real-time distribution of substation loads under fault conditions, the Company proposes the simultaneous deployment of substation automation and distribution automation. In years 2009 through 2014, DP&L plans to automate 6-7 substations per year and in the final year of the development phase, 2015, will automate an estimated 12 substations. Subsequent to the 7-Year development phase the Company expects to continue to automate substations the rate of 12 per year through 2023.

Table 2.3.2.a Total Smart Grid Development Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Distribution Automation	1,643,261	1,817,976	1,840,162	1,844,183	1,818,115	1,796,869	8,768,997	**19,529,563**
Substation Automation	5,895,123	5,409,807	3,262,554	1,945,521	1,385,234	1,673,764	2,500,938	**22,072,941**
Total	7,538,384	7,227,783	5,102,715	3,789,704	3,203,350	3,470,632	11,269,935	41,602,503

source: WPI-1

[1] See detail of DP&L's proposed energy efficiency & demand Response programs and AMI plan in *The Dayton Power & Light Energy Efficiency & Demand Response Plan* and *The Dayton Power & Light Advanced Metering Infrastructure Plan*

Table 2.3.2.b Total Smart Grid Development O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Distribution Automation	108,579	131,884	154,908	177,663	200,278	222,641	244,762	1,240,715
Substation Automation	-	353,840	474,160	540,395	572,889	577,808	582,871	3,111,961
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPI-1

2.3.3 Energy and Demand Savings

DP&L expects to begin to realize a reduction in line losses of 54,110 MWh from grid automation through 2015. This reduction will be accomplished through the efficient placement of capacitor banks and modeling the distribution circuit which, with the help of the AMI information, will allow DP&L to reduce energy losses on the distribution system.

Elements of distribution and substation automation can also be utilized to assist the reduction of power demands on peak load days. One of the operational characteristics of the distribution system that can be managed through distribution automation is the voltage profile along the feeder. Since loads are dynamic and the amount of current affects the voltage drop along the feeder, by use of voltage monitoring and dynamic switching of capacitors and regulators, it is possible to control the voltage profile. Based on successes at other utilities, DP&L expects to be able to trigger voltage changes at peak times, also known as dynamic voltage control ("DVC"), thus reducing peak demand by 5.3 MW in year 2015.

Table 2.3.3 Summary of Energy and Demand Savings

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Energy Savings (MWh)	1,405	2,823	4,086	5,508	6,928	8,339	25,023	54,110
Demand Savings (MW)	0.3	0.6	0.9	1.2	1.5	1.8	5.3	

3 Integrated Business Case for CCEM Programs

3.1 Total Costs

Over a seven-year period the Company will require $297M in capital and $186M in O&M to build the necessary infrastructure and service offerings to provide immediate customer benefits, to offer customers the ability to control their energy usage, to continue to meet the needs of customers for safe, low-cost, and reliable electricity and to meet the targets set forth in S.B. 221.

Table 3.1.a Total CCEM Deployment Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Energy Efficiency & Demand Response	-	504,950	-	-	-	-	-	504,950
AMI	59,954,305	54,406,165	41,044,733	37,204,912	34,191,526	26,760,572	1,455,146	255,017,361
Smart Grid Proof of Concept	7,538,364	7,227,783	5,102,715	3,789,704	3,203,350	3,470,632	11,269,935	41,602,503
[illegible]	[illegible]	62,138,898	46,147,449	40,994,616	37,394,876	30,231,204	12,725,081	297,124,814

source: WPG-1, WPH-1, WPI-1

Table 3.1.b Total CCEM Deployment O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Energy Efficiency & Demand Response	8,968,078	13,512,652	16,465,389	17,751,721	19,539,193	20,723,309	21,457,239	118,437,680
AMI	1,074,231	3,869,626	8,495,867	11,402,945	12,261,975	13,068,571	12,894,590	63,067,704
Smart Grid Proof of Concept	108,579	495,724	629,068	718,058	773,167	800,447	827,633	4,352,677
[illegible]	10,150,888	17,867,902	25,590,325	29,872,723	32,574,335	34,592,326	35,179,462	185,847,961

source: WPG-1, WPH-1, WPI-1

3.2 Total Benefits

3.2.1 Operational Benefits

As a direct result of CCEM implementation, the Company can expect to achieve operational savings or capital deferral in the amount of $52.8M over the seven years covered in this filing request. Detail of 7-year operational benefits can be found in *The Dayton Power & Light Company Advanced Metering Infrastructure Plan* and *The Dayton Power & Light Company Smart Grid Development Plan.*

Table 3.2.1 Total CCEM Operational Benefits 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Energy Efficiency & Demand Response	-	-	-	-	-	-	-	-
AMI	117,483	1,054,683	2,816,216	7,680,445	10,789,423	13,822,779	15,429,601	51,712,630
Smart Grid Proof of Concept	22,858	62,598	104,740	147,314	189,986	235,438	364,932	1,127,866

source: WPH-1, WPI-1

3.2.2 Societal Benefits

Other savings resulting from the implementation of CCEM programs will accrue to customers, the market, and to society. To assist in presenting and quantifying these societal benefits, DP&L in conjunction with other Ohio utilities, commissioned The Electric Power Research Institute ("EPRI") to prepare the study entitled, "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investment." The EPRI report developed a framework for organizing and valuing societal benefits associated with AMI. DP&L adapted the framework to capture benefits from the integrated CCEM proposal. Exhibit 3.2.2.a summarizes the approach to understanding and valuing the overall societal benefits of the CCEM programs.

Exhibit 3.2.2.a Societal Benefits Framework

Source of Benefits	CCEM Initiative	Value Component
Demand Response Products	Demand Response Programs (enabled by AMI)	Capacity Energy
Improved Utilization Efficiency	Energy Efficiency Programs HED	Capacity Energy
Other Products and Services	Not Applicable	Revenue
Enhanced Service Quality	AMI Smart Grid Development	Outage Duration
Macroeconomic Impacts	Not Applicable	Unemployment/Wages
Externalities (Carbon Emissions)	Demand Response Programs Energy Efficiency Smart Grid Development	Market Value of Emissions
Distribution Network Efficiency	Smart Grid Development	Capacity Energy

Sourced: Based on Framework Developed by EPRI

Demand Response Products

Universal deployment of AMI enables greater demand response by making all consumers potential participants in time-varied pricing or load control programs. Increased participation in demand response programs results in both capacity and energy savings.

Improved Utilization Efficiency

CCEM programs improve end-use efficiency in two ways: (1) the rollout of AMI and corresponding HEDs and enhanced web information provide consumers with timely and readily available information about their electricity usage pattern and its corresponding cost, knowledge that will result in a reduction in the overall use of electricity; and (2) DP&L's proposed energy efficiency programs provide incentives to further curtail energy consumption. Improved utilization efficiency results in both energy and capacity savings.

Other Products and Services

EPRI suggests that new revenue streams may become viable as supplemental services are enabled by AMI. DP&L is not seeking recovery for any investment associated with new products and services at this time.

Enhanced Service Quality

The source of this benefit is advanced metering and smart grid capabilities that enable the utility to reduce the frequency or duration of electrical outages.

Macroeconomic Impacts

EPRI suggests that changes in regional economic output, such as employment and wages, may be attributable to AMI. It would be speculative to quantify such impacts at this time.

Externalities

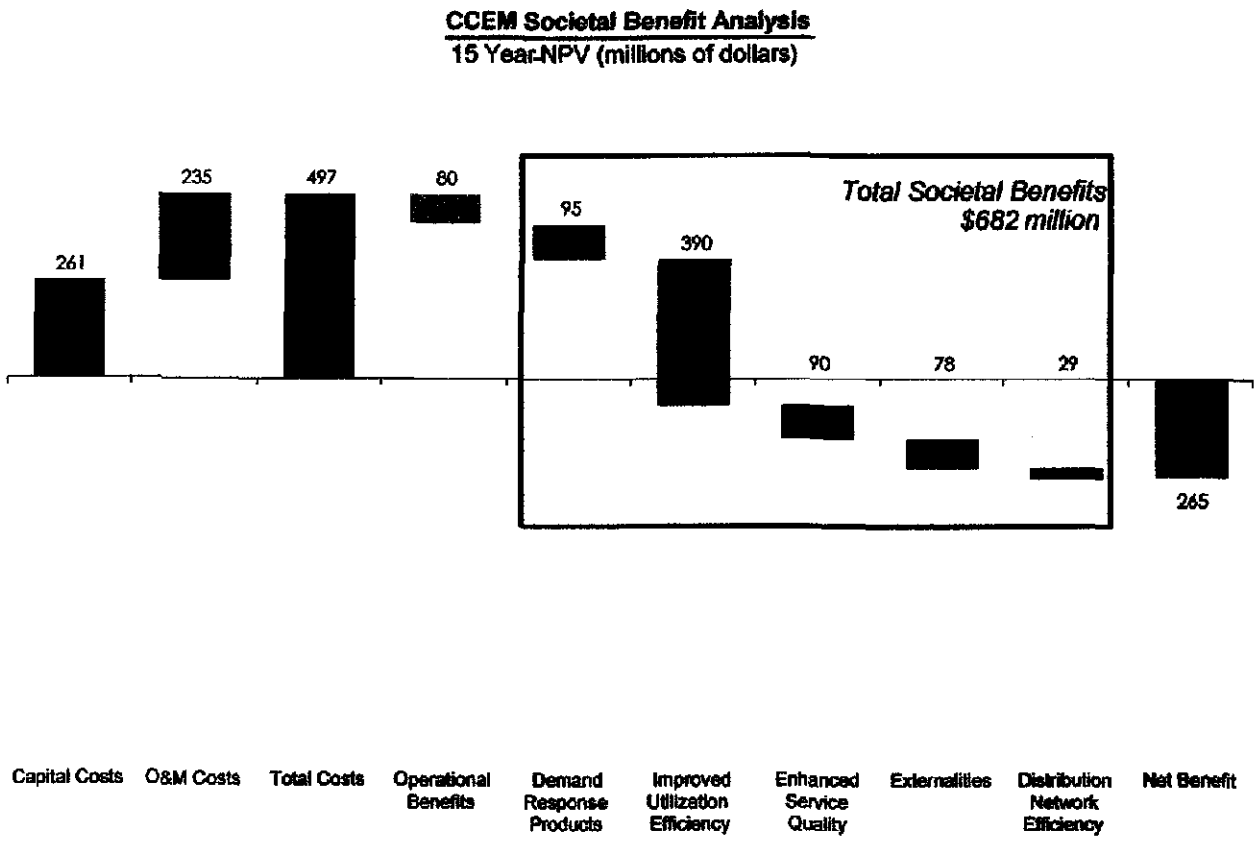
Reductions of externalities are secondary benefits associated with kW and kWh impacts attributable to another benefit source, such as demand response or feedback. For the purposes of quantifying externalities from CCEM programs, DP&L has estimated the value of reduced carbon emissions associated with demand response, energy efficiency programs, and reduced line losses from smart grid development.

Distribution Network Efficiency

DP&L added this category of societal benefits to the EPRI framework. This category accounts for the reduction in energy and peak demand associated with the smart grid investments. In particular, the investments in distribution and substation automation will reduce line losses and allow reductions in peak demand via dynamic voltage control.

Exhibit 3.2.2.b summarizes the results of DP&L's societal benefits analysis and presents a view of the total costs and benefits of CCEM. The Company needed to select an appropriate period to measure the societal benefits from CCEM programs. The Company selected 15 years because that period coincides with the depreciable life of the AMI meters and with the end of the total program expenditures for the CCEM project.

Exhibit 3.2.2.b Total Costs vs. Benefits of CCEM

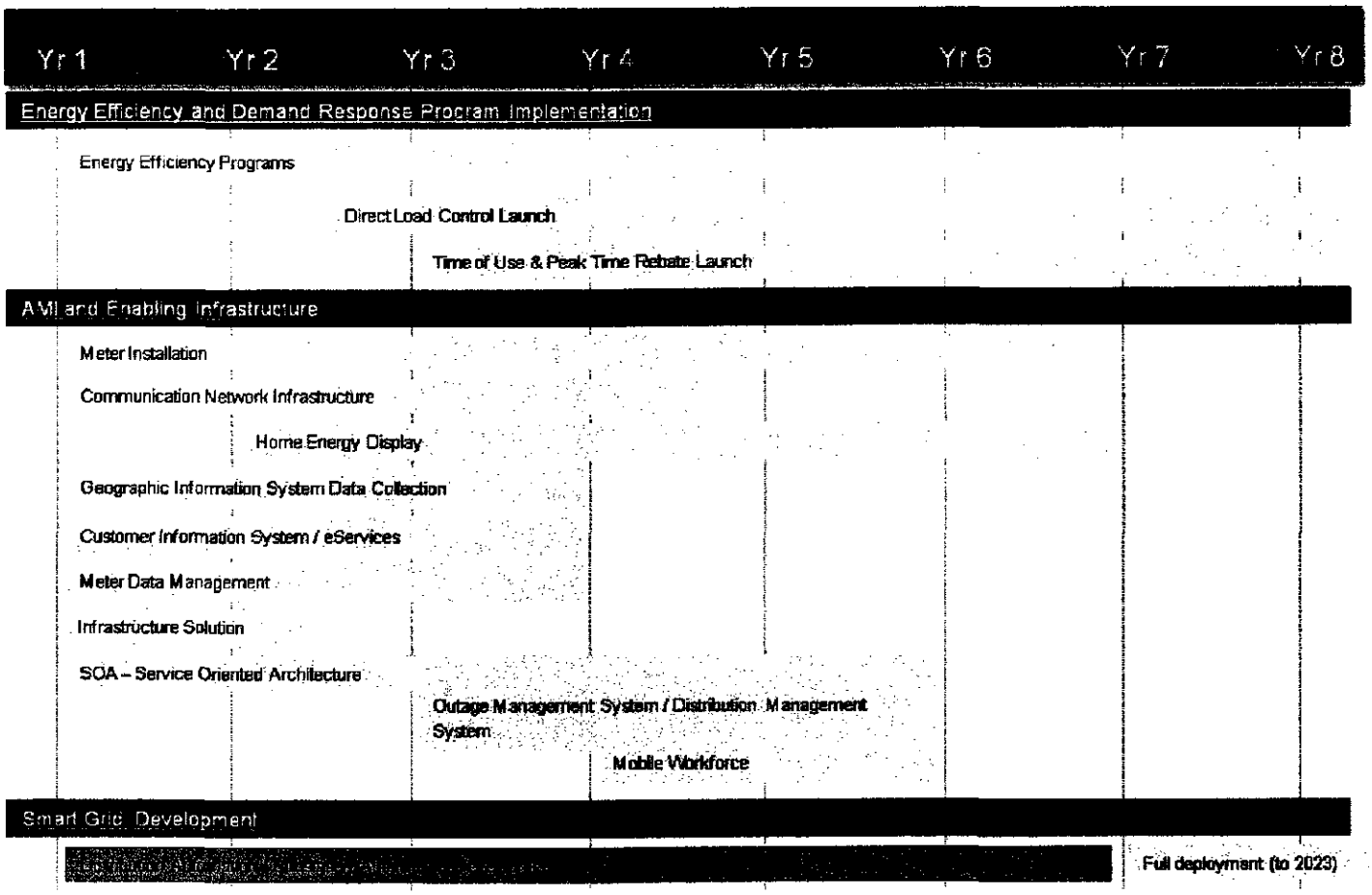


4 CCEM Implementation Plan

4.1 Deployment Schedule

The Company expects to begin implementation of energy efficiency programs in January of 2009 and the remainder of CCEM initiatives within 30 days of Commission approval. For purposes of the exhibit below, it is assumed that all implementation begins in January of 2009.

Exhibit 4.1 DP&L's CCEM Deployment Pan



4.2 Change Management

As with any major organizational undertaking, the introduction of CCEM programs will necessitate significant changes to all levels of the organization. These enterprise-wide changes

will impact both the systems and infrastructure the DP&L employees use on a day-to-day basis and the way in which they do their jobs.

Ultimately, the value derived from this project depends on the people using the systems and the way in which they use them. Change management is much more than training and includes the following three components:

- Job Design which assists in designing the new way the DP&L employees will do their work (business process design) and analyzing the organization to ensure the right skills will be there to support the way work is done in the future.
- Training and Performance Support which consists of developing and executing the specific training needs for the new systems and business processes, and developing the appropriate performance metrics to help ensure that the employees are focused on the performance goals. Which they need to accomplish in order for DP&L to achieve maximum success.
- Communications and Employee Engagement which consists of developing a communication plan in order to ensure the key messages are delivered at the right time to all levels of the organization. One of the many questions the communication plan will answer is the critical "why should I do this" question that is frequently asked by employees during periods of significant change.

A comprehensive change management program will be required to successfully deploy CCEM programs. Benefits of a successful change program include:

- Significantly reduced business disruption – disruptions to customer service, field activities and productivity are controlled and minimized.
- Benefits realized – behavior shifts are achieved on schedule and new ways of working are "institutionalized."
- Sustainable solutions– continuous improvement occurs naturally without external support and there is no "going back."

- Enhanced leadership capability – high-performing companies take advantage of changes as a "crucible of leadership" to build leadership skills down to the front-line supervisor level.
- Reliance on departing workforce minimized – "institutional memories" are captured and support tools enabled to allow for on-going use.
- Union employees are involved in the "right" way – these employees participate in the changes and experience them as a normal part of the way of doing business in their self-interest.

5 Customer Rate Impact

The CCEM programs are an integrated infrastructure improvement and energy efficiency plan. The infrastructure improvements are targeted at enabling the energy efficiency programs. Without the infrastructure improvements the energy efficiency programs could not be offered on a wide scale, they could not be operated effectively and their impact could not be measured and verified. Moreover, the infrastructure investment and energy efficiency programs could not effectively function independently. When the Company refers to infrastructure improvement or energy efficiency programs, it refers to the integrated programs and jointly considers their impact.

A brief background discussion on the proposed rate riders is helpful in understanding the customer impacts. Both the CCEM Infrastructure Investment Rider ("IIR") and Energy Efficiency Rider ("EER") are cost recovery mechanisms; each is separate and intended to recover a specific cost structure. The IIR is reflective of the specific cost characteristics of the CCEM Infrastructure Investment which contains the AMI (metering) system, smart grid and complex billing system (software) costs. The metering and billing systems are customer-related costs and their proposed recovery is through a customer-based charge. The remaining costs are associated with the more efficient delivery of energy and they are recovered on an energy (kWh) basis. The costs recovered by the EER rider are entirely dedicated to the more efficient use of energy by all DP&L users and the proposed recovery is through an energy-based (kWh) charge.

The traditional perspective of a typical customer impact is not descriptive of these programs; the key perspective is from that of a program participant versus a non-participant. For the residential class, the contrast between participating customers and non-participating customers can be made at typical consumption levels (750 & 1,000 kWh monthly usage), and 1,500 kWh is representative of the residential heating class. For the C&I classes it works best to select representative customers, who are reflective of the class, for their usage characteristics. The single-phase secondary customer bills were calculated with 1,543 kWh and 8 kW and the three-phase secondary bills were calculated with 30,000 kWh and 101 kW. Primary customer bills were calculated at 200,000 kWh and 500 kW.

For this purpose, DP&L assumed rates will remain about the same through 2010 with two known changes. First the Residential Generation discount will expire in December of 2008, and second, the Environment Investment Rider ("EIR") will change in January 2009 and in January 2010. Rate structures could change significantly when the Rate Stabilization Period expires in 2010 and that new structure is unknown at this time. Therefore, for the purposes of this analysis, the Company assumed the current rate structures remain in place through the seven-year project horizon and that all rates other than IIR and EER riders increase at 3.25% per year (beyond 2010) to reflect the impact of inflation. The IIR components will remain constant while the EER will be reflective of program costs.

Table 5.a lists the level of monthly savings a participating customer can earn versus a non-participating customer. These comparisons are based on 2009 rates and assume that a participating customer takes part in all EE programs applicable to them and a non-participating customer takes part in none of the programs. In each case participating customers lower their energy costs by taking advantage of the EE programs available to them.

Table 5.a Energy Efficiency Program Participation vs. Non-Participant Savings

Description	Non Participant	Participant	Difference	Percent
Residential: 750 kWh 1,000 kWh	 $92.67 $117.45	 $78.80 $101.29	 ($13.87) ($16.16)	 -14.97% -13.76%
Resi Heat (s) 1,500 kWh	$166.61	$142.47	($24.14)	-14.49%
Resi Heat (w) 1,500 kWh	$147.67	$129.68	($17.99)	-12.18%
Secondary Single Phase	$228.03	$177.59	($50.44)	-22.12%
Secondary Three Phase	$2,869.01	$2,607.24	($261.77)	-9.12%
Schools	$4,359.51	$4,123.05	($236.46)	-5.42%
Primary	$14,954.49	$14,016.42	($938.07)	-6.27%

Table 5.b lists the monthly impact of EE programs on customers by comparing participating customer bills against customer bills where there were no EE programs. Residential and C&I Single-Phase, Three-Phase and Primary customers are significantly better off with EE and DR programs than without. Many of the largest customers are already involved with their own EE and DR programs so that they may have the option of participating in DP&L's programs or opting out. Large C&I customers (Primary-Substation and High Voltage) each have unique consumption characteristics and they would have to be evaluated on a case-by-case basis to assess program impacts so they are excluded from the table.

Table 5.b Energy Efficiency Program Participation Bills vs. No Energy Efficiency Programs Implemented

Description	Participant With EE	No Programs Implemented	Difference (Savings)	Percent
Residential: 750 kWh 1,000 kWh	 $78.80 $101.29	 $87.18 $111.20	 ($8.38) ($9.91)	 -9.61% -8.91%
Resi Heat (s) 1,500 kWh	$142.47	$158.86	($16.39)	-10.32%
Resi Heat (w) 1,500 kWh	$129.68	$139.92	($10.24)	-7.32%
Secondary Single Phase	$177.59	$210.41	($32.82)	-15.60%
Secondary Three Phase	$2,607.24	$2,765.97	($158.73)	-5.74%
Schools	$4,123.05	$4,216.48	($93.43)	-2.22%
Primary	$14,016.42	$14,341.16	($324.74)	-2.26%

The savings grow about 20% over the period because the IIR is fixed throughout the period while the EER increases to keep pace with program expenditures. All other rates and charges are increased at 3.25% to account for the cost of inflation. Participants will continue to see savings during the period 2009 – 2015. Exhibits 5.a through 5.h show the savings participating customers can expect versus those customers who do not participate.

Exhibit 5.a **Residential (750 kWh)**

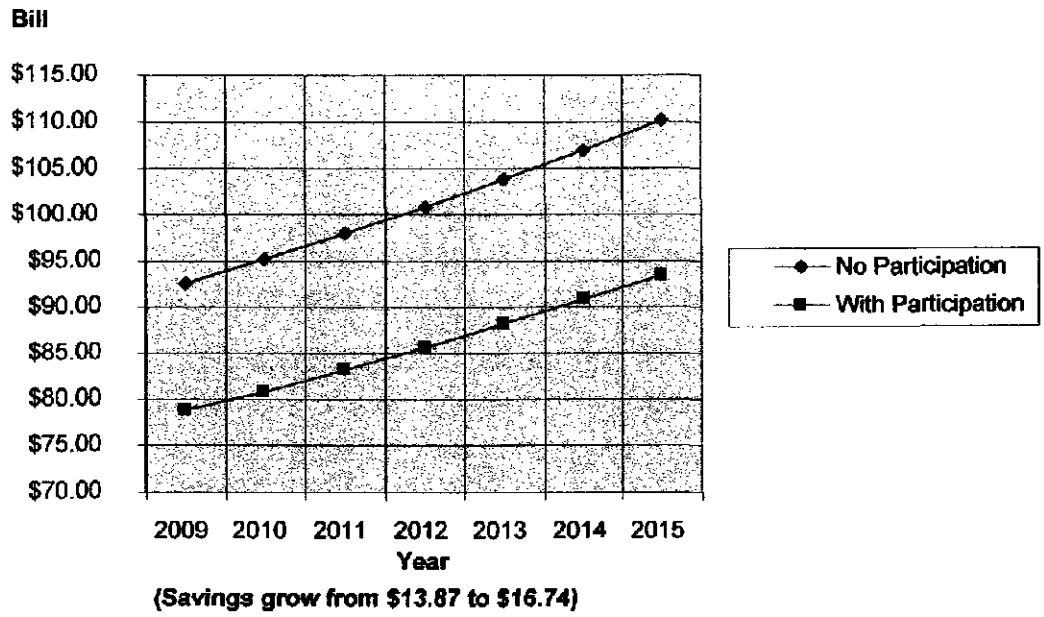


Exhibit 5.b **Residential (1,000 kWh)**

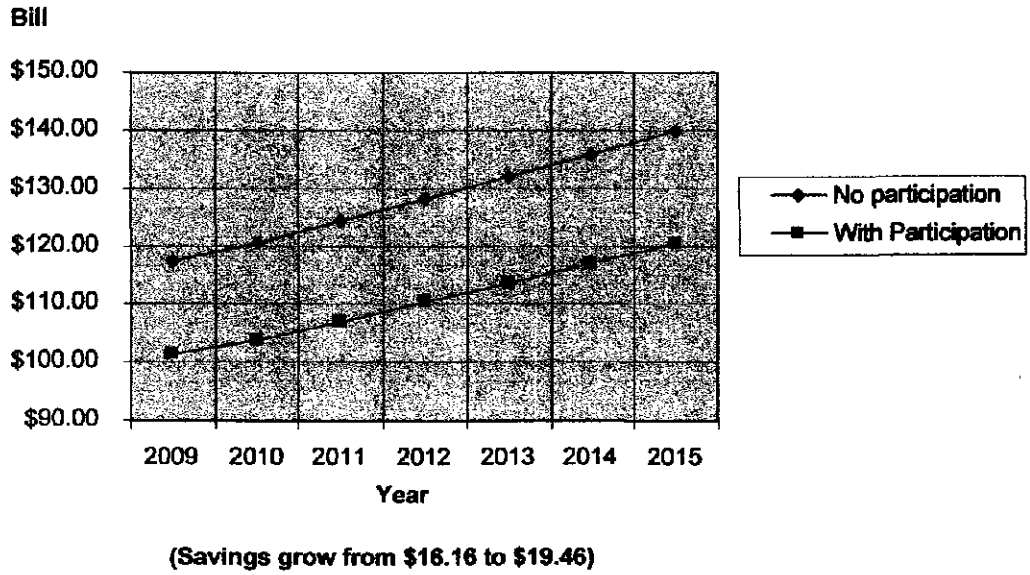


Exhibit 5.c **Residential Heat (S)**

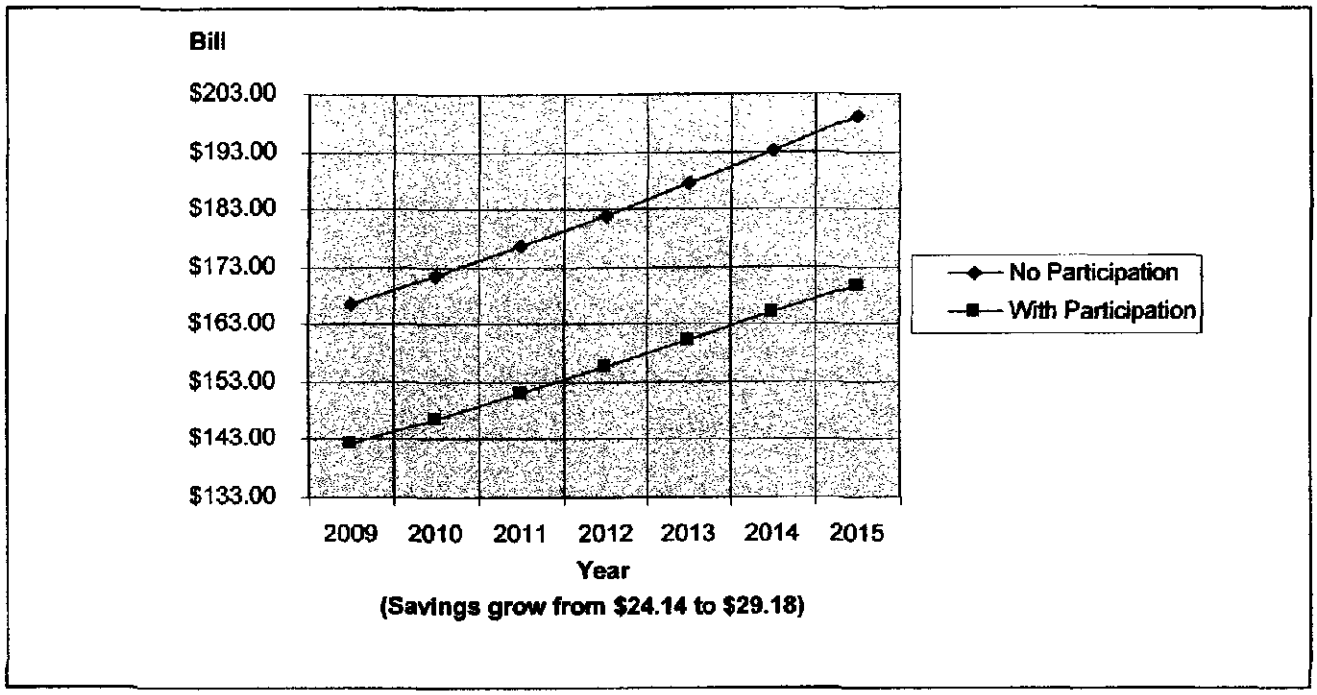


Exhibit 5.d **Residential Heat (W)**

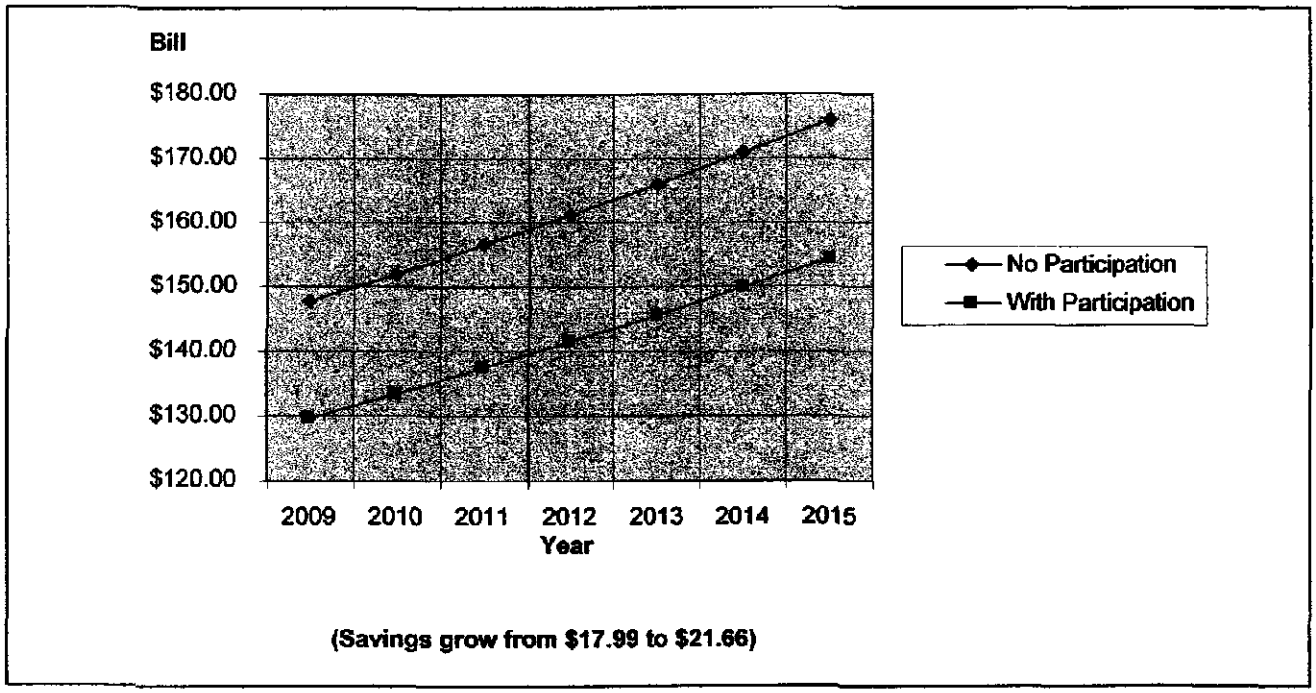
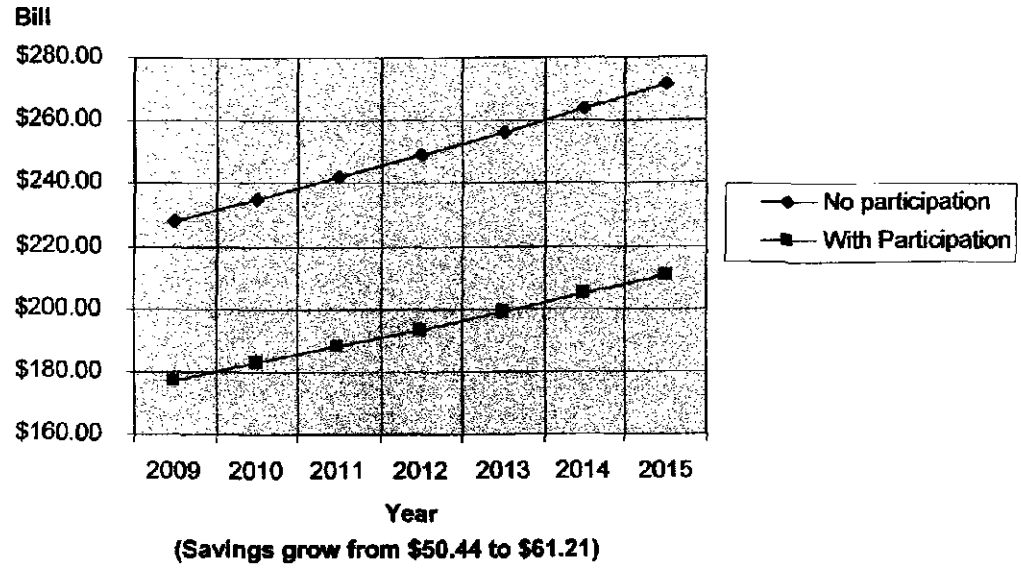
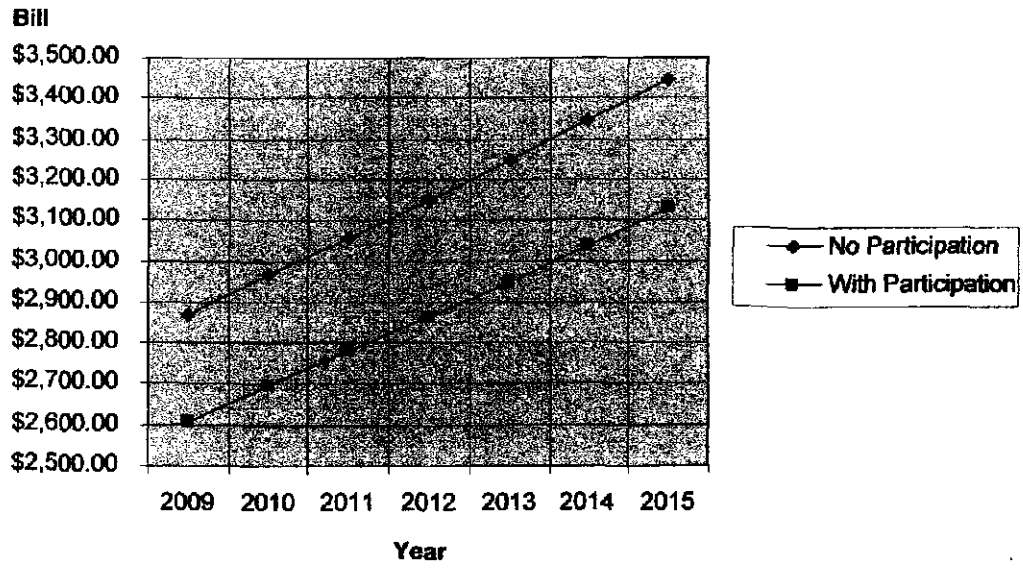


Exhibit 5.e **Secondary – Single Phase**



(Savings grow from $50.44 to $61.21)

Exhibit 5.f **Secondary – Three Phase**



(Savings grow from $261.77 to $317.75)

Exhibit 5.g **Primary Service**

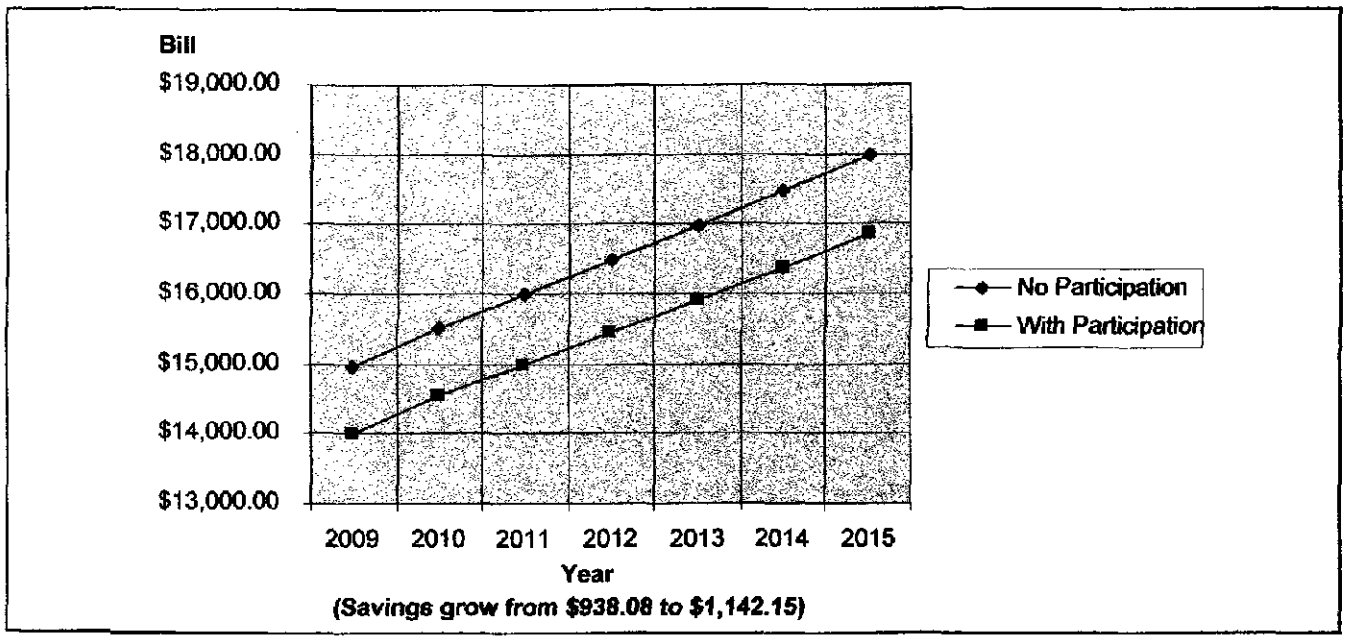
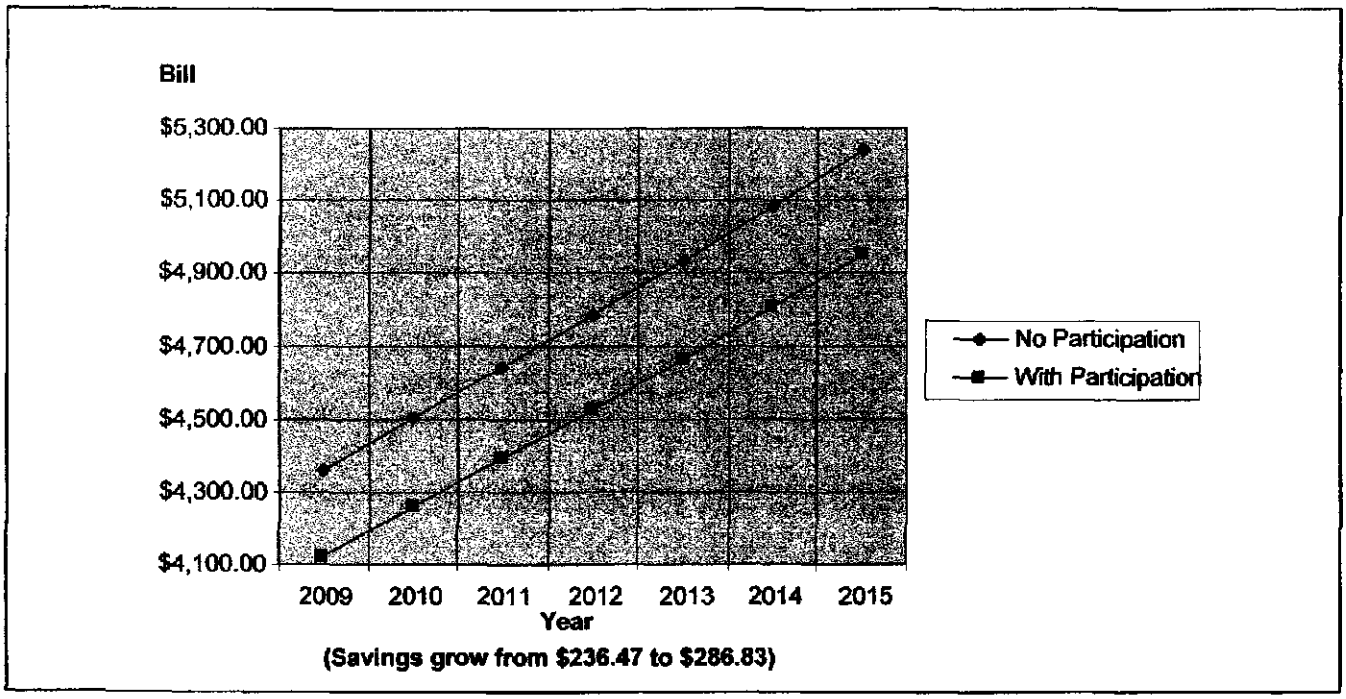


Exhibit 5.h **Schools**



Customers will have the ability to control their energy costs by participating in the Company's EE programs. In order to maximize savings, customers need to participate in as many programs as possible and to maintain that participation year after year. The range of programs is wide enough that every customer should be able to participate in some of the programs and gain an opportunity to save. Rate structures may change during the period but that should not significantly change the customer's opportunity to save on their bill. In fact new rate structures will offer customers new opportunities to save. The key for customers is to participate in as many programs as possible and keep participating to secure lower energy costs in the future.

6 Infrastructure Investment Rider

The Infrastructure Investment Rider ("IIR") is designed to recover the costs associated with the new automated metering infrastructure (AMI) systems, telecom systems, substation automation systems, and IT systems including a new billing system. These are all functions that are necessary to build a delivery system of the future, or smart grid system, which is the necessary platform for which all of the energy efficiency programs can be provided to customers. Therefore, DP&L proposes that the IIR be non-bypassable for all customers.

The IIR was developed by calculating a revenue requirement based on the costs expected to be incurred for the infrastructure improvement portion of the CCEM programs. A rate of return based on June 30, 2008 DP&L capital structure was applied to capital investments over the initial seven year period. Operational and maintenance expenses, as well as depreciation expenses, taxes other than income taxes were added to form the base revenue requirement. The Company incurred project development costs beginning in 2007 and is incurring additional expenses in 2008. A carrying cost, equal to the rate of return, was applied to those costs until they are fully recovered via the IIR and EER riders. This cost was either directly assigned or allocated to the EER and IIR and built into rate recovery over a three-year period.

As part of the CCEM comprehensive plan, the Company will be implementing AMI meters system-wide over a six-year period. All meters currently in service will be replaced by more advanced meters. The meters that are taken out of service before the end of their useful

lives, less any salvage value, will be stranded. Thus, the stranded cost of meter investment is added to the IIR revenue requirement on a net plant basis, consistent with the timing at which the meter is taken out of service. The gross plant value of the retired meters is subtracted from the gross plant balance for each year during CCEM deployment, so that the value is not double-counted in the rate recovery calculation. In addition, the cost of preparing and litigating the CCEM case before the Commission is calculated on Schedule C-8, added to the revenue requirement, and is assumed to be recovered over a three-year period, consistent with Commission precedent. Two separate gross revenue conversion factors were calculated on Schedule A-4, and applied to debt and equity return components to reflect the relevant tax impacts.

To appropriately account for the O&M expenses that will be saved from implementing the infrastructure improvements as well as depreciation savings, fifty percent of this amount was credited to the revenue requirement. This approach is consistent with ORC §4928.143(B)(2)(h) which permits shared savings to be included in a utility's energy delivery modernization plan. The fifty percent factor allocates the savings to the utility and customers equally.

ORC §4928.143(B)(2)(h) also provides for incentives and revenue decoupling mechanisms with respect to a utility's energy delivery modernization plan. DP&L is proposing a flat per month per bill recovery mechanism for a portion of the infrastructure investment costs. The Company recognizes that the majority of these infrastructure improvement costs are customer-driven costs, costs that vary based on the number of customers served by DP&L, or based on the number of bills rendered on a monthly basis. The per-customer per-month fee was calculated by taking the average annual revenue requirement over the initial seven-year period and determining how much of this amount was customer-related. The average annual customer-related IIR revenue requirement was then assigned to the various tariff classes based on a weighted average number of customers. The weighting factor from the Company's last rate case cost of service study, Case No. 99-1687-EL-ETP was used to allocate the IIR revenue requirement to each tariff class. The allocated revenue requirement was then divided by 2007 average number of customers and the result is a price per customer per month for Infrastructure Improvements. Because this rate design levelizes the IIR charges, in the early years recovery is

occurring faster than the investment is being made. For that reason, the time value of money was calculated for the years in which speedier recovery was expected, and the resulting carrying costs were subtracted from the revenue requirement such that it reduced the total amount of revenue recovered from customers overall.

Finally, the remainder of the IIR revenue requirement was divided by adjusted sales to derive an average rate per kWh of approximately 0.14 cents. Through the normal course of business the Company prepares a corporate sales forecast. The expected energy efficiency savings that result from implementing the energy efficiency programs contained in this plan were subtracted from the corporate sales forecast by year. The resulting adjusted sales were used as the denominator to develop the IIR per kWh charge rate.

The IIR is contained on Tariff Sheet No. D42 which can be found in Schedule E-3 of this filing.

7 Energy Efficiency Rider

In compliance with ORC §4928.66, DP&L is required to implement energy efficiency and demand response programs to meet the annual targets set forth in this section of the legislation. The Energy Efficiency Rider ("EER") is designed to recover the costs associated with energy efficiency and demand response programs that DP&L plans to offer to customers beginning in 2009. For a more detailed explanation of the programs DP&L will be offering, see Section 2.1 of this document.

The EER was developed from cost estimates for developing and implementing the energy efficiency programs, which were used to calculate a revenue requirement for the EER. Although there is very little capital costs associated with the EE programs DP&L plans to implement, a rate of return was applied to the capital investment expected to be incurred. Operational and maintenance expenses, as well as depreciation expenses, taxes other than income taxes were added to form the base revenue requirement. The Company incurred project development costs beginning in 2007 and is incurring additional expenses in 2008. A carrying cost, equal to the rate of return, was applied to those costs until they are fully recovered via the IIR and EER. This cost was either directly assigned or allocated to the EER and IIR and built into rate recovery over

a three-year period. Two separate gross revenue conversion factors were calculated on Schedule A-4, and applied to debt and equity return components to reflect the relevant tax impacts.

Consistent with ORC §4928.143(B)(2)(h), the Company calculated the lost revenues that will occur as a result of implementing the energy efficiency programs. The estimated energy savings impact from the EE programs was calculated by year by tariff class. Estimated rates by tariff class were applied to those energy savings to determine the amount of lost revenue the Company will experience. The level of fuel expenses that is currently built into rates was backed out of this calculation with the expectation that if the retail energy sale did not occur, the fuel expense would not be incurred by the Company. Thus, the lost revenue was lowered to account for unused fuel. The lost revenues that resulted were summed and added to the EER revenue requirement.

The resulting total revenue requirement was then divided by sales to determine an energy efficiency rate per kWh by year. The energy efficiency rate is approximately $0.0015 / kWh starting in 2009, and grows to approximately $0.0068 / kWh by 2015. This rate increases each year as additional spending on energy efficiency programs is incurred each year to meet the increasing annual energy and demand reduction targets contained in S.B. 221. Consistent with 4928.66(A)(2)(c), this charge is bypassable by a mercantile customer that implements its own energy efficiency measures and meets the Commission's rules that carry out this provision.

The EER is contained on Tariff Sheet No. D43 which can be found in Schedule E-3 of this filing.

8 CCEM Acronyms

Several acronyms, defined here, are referenced throughout the body of DP&L's Customer Conservation and Energy Management filing.

Acronym	Definition
AMI	Advanced metering infrastructure
BPL	Broadband over powerline
C&I	Commercial & industrial
CAP	Community Action Partnership
CFL	Compact fluorescent lights
CIS	Customer information system
CPP	Critical peak pricing
DA	Distribution automation
DAD	Dispatch administration database
DEER	Database for energy efficient resources
DMS	Distribution management system
DR	Demand response
EE	Energy efficiency
EM&V	Evaluation, measurement and verification
EPP	Electric Partnership Program
EPRI	Electric Power Research Institute
EIR	Environment Investment Rider
GIS	Geographic information system
GW/GWh	Gigawatt
HAN	Home area network
HED	Home Energy Display
HVAC	Heating, ventilation and air conditioning
HWAP	Home Weatherization Assistance Program
II	Infrastructure Investment
IP	Internet protocol
IVR	Interactive voice response
KW/kWh	Kilowatt/Kilowatt hour
LMS	Load management system
MDMS	Meter data management system
MWFMS	Mobile workforce management system
O&M	Operating and maintenance
OMS	Outage management system
PLC	Powerline carrier
RF	Radio frequency
RFP	Request for proposal

RTU	Remote terminal unit
SA	Substation automation
SCADA	Supervisory control and data acquisition
SOA	Service oriented architecture
SONET	Synchronous optical networking
TCMS	Trouble call management system
TRC	Total resource cost
VAR	Volt-ampere reactive power
WANS	Wide area network systems

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

Chapter 2
Energy Efficiency and Demand Response Plan 2009-2015
The Dayton Power & Light Company

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1 Introduction

1.1 Overview

1.1.1 Background

The Dayton Power and Light Company ("DP&L" or "Company") remains focused on providing customers with safe, low-cost, reliable electric service, and through this filing is seeking to offer customers tools to control further their energy usage and costs. With the advent of new technologies, increased environmental awareness and new state legislation creating energy efficiency and peak demand targets, DP&L seeks to offer its customers an aggressive and comprehensive set of Energy Efficiency (EE) and Demand Response (DR) programs. By this filing, DP&L also seeks approval for the recovery of the costs and lost revenues involved in providing these programs.

This filing conforms to the requirements in Ohio law contained in Am. Sub. S.B. 221, signed into law by Gov. Strickland on the 1st of May, 2008. With the suite of programs and initiatives to be implemented, and given that technology advances will make additional cost-effective opportunities reasonably available in future years, DP&L should meet the energy and demand reduction targets set out in this Bill.

1.1.2 Objective

The Company's Energy Efficiency and Demand Response Plan ("Plan") represents a commitment by DP&L to enhance our customers' energy value through implementation of a robust and flexible portfolio of energy efficiency and demand response solutions. Customers who choose to participate will gain the ability to exercise more control over their energy usage and expenditures. These solutions together with the Company's advanced metering and smart grid plan, supported in *The Dayton Power and Light 2009-2015 Advanced Metering Infrastructure Plan* and *The Dayton Power and Light 2009-2015 Smart Grid Development Plan*, will also reduce the region's environmental impact by dramatically slowing the growth rate of energy usage and peak demand. These results are in line with the requirements of R.C. Section 4928.66 and will allow DP&L to offer more efficient, reliable electric service as well as an enhanced customer experience and improved customer service.

1.2 Executive Summary of Energy Efficiency and Demand Response Plan

DP&L's Plan is targeted toward all customer segments. The Plan has three primary elements.

1. ***Residential Portfolio.*** The residential portfolio offers customers multiple opportunities to control their energy usage and costs while promoting comprehensive actions that can create the most value for customers. Specific program elements include:

   - **Residential Lighting.** This program will initially focus on buying down the cost of compact fluorescent light bulbs ("CFL") sold at the retail level. Over time, DP&L may expand this program to include energy efficient fixtures as well as other types of efficient lighting.

   - **Residential Heating, Ventilation and Air Conditioning ("HVAC") Diagnostic & Tune-Up.** Under this program HVAC technicians are trained in proper refrigerant charge and airflow techniques, and customers are offered incentives to have their residential HVAC units tuned up.

   - **Residential HVAC Rebates.** This program provides rebates to customers who purchase new energy efficient HVAC units.

   - **Residential Appliance Recycling.** This program provides customers with a payment for a working, inefficient window air conditioner or a second refrigerator or freezer. The program also provides for the removal and recycling of these inefficient appliances.

   - **Residential Appliance Rebate.** This program provides rebates to customers that purchase qualifying Energy Star freezers, dishwashers, room air conditioning units, dehumidifiers and ceiling fans.

   - **Residential Low Income Affordability.** DP&L will fund energy audits for low-income customers. Recommendations from the audit that are found to have a benefit-

to-cost ratio better than 1.0 will be directly funded and implemented through this program.

- **Residential Direct Load Control.** This program provides eligible participants with a programmable thermostat installed at no cost in exchange for allowing DP&L to cycle the central air conditioning unit on and off during peak periods.
- **Residential Time-of-Use Pricing.** A voluntary time-of-use pricing option will be made available to residential customers once sufficient infrastructure is in place. This tariff will feature a lower rate during off-peak hours and a higher rate during on-peak hours. Customers choosing to participate in this pricing option will have the ability to save money by shifting usage to off-peak periods.
- **Residential Peak Time Rebate Pricing.** Under this pricing option, customers that reduce their energy consumption during peak periods below a pre-established baseline will receive a rebate from DP&L. This service will be offered in January, 2011 to residential customers who have advanced meter infrastructure in place. Based on the success of this effort, DP&L intends to make the program available to all residential customers with interval meters.

2. ***Non-Residential Portfolio.*** The portfolio includes a wide variety of individual technology and/or device incentives. Specific program elements include:

- **Non-Residential Prescriptive Rebates.** This program offers incentives for designated commercial and industrial efficiency measures such as improved lighting technologies, efficient motors and drives, and efficient compressed air systems. Incentives will be fixed and paid on a per measure basis. As the Company gains experience with the program and customer needs, the list of prescribed measures will be revised. All measures for which a prescriptive incentive is offered will have a benefit-to-cost ratio of greater than 1.0.
- **Non-Residential Custom Rebates.** This program offers incentives for more complex measures, including industrial process improvements and new building construction.

Any cost-effective measure that improves a customer's electric energy efficiency will be considered for an incentive. Incentive levels will be project-specific and based on prescribed calculations. In order to receive an incentive, a project must have a benefit-to-cost ratio of greater than 1.0.

- **Non-Residential Direct Load Control.** The Direct Load Control program provides eligible participants with a programmable thermostat that is installed at no cost, and can be programmed via the internet. During peak summer conditions or periods of regional operating constraints, DP&L can signal the thermostat to cycle the air conditioner on and off, which will reduce load on DP&L's system and result in a temperature increase of only a few degrees Fahrenheit.
- **Non-Residential Time of Use Pricing.** Several time-of-use pricing tariffs will be offered to non-residential customers. The electric rates are higher during peak hours and lower during off-peak hours, and some tariffs will offer a critical-peak pricing feature whereby the electric rate during extreme peak hours is significantly higher than the rate during all other hours.

3. ***Education / Awareness / Market Transformation Activities.*** In addition to the Residential and Non-Residential Portfolios, DP&L will implement educational outreach initiatives to build and expand consumer energy management awareness. DP&L will leverage and enhance existing energy education venues and networks such as its website, various customer communications modalities and school presentations to maximize the public's exposure to these initiatives. We will also explore partnering with energy-efficiency vendors and channel partners to build an energy efficiency showcase and educational facility.

4. ***Infrastructure Enhancements.*** In addition to these programs, energy and demand reductions shall also be achieved through the proposed distribution automation system enhancements and home energy displays discussed in *DP&L's Advanced Metering Infrastructure Plan* and *DP&L's Smart Grid Development Plan*.

Although we believe that this Plan provides the best suite of programs to aid DP&L's customers in achieving energy and demand reductions, we shall evaluate customer participation and recognize that we may need to alter the individual programs as well as add and/or delete programs in response to implementation experience and market conditions.

Table 1.2 Summary of Costs and Energy/Demand Savings 2009-2015

	7-Year O&M Costs	7-Year Capital Costs	7-Year Energy Savings (kWh)	Yr. 7 Demand Savings (kW)
Residential Portfolio				
Lighting	$20,143,118		765,028,964	16,637.7
HVAC Diagnostic & Tune-Up	$8,442,276		77,165,688	17,779.7
HVAC Rebate	$11,030,628		39,977,000	9,649.5
Appliance Recycling	$2,470,570		89,448,507	3,850.3
Appliance Rebates	$1,413,207		23,023,161	744.0
Low Income Affordability	$7,715,198		47,744,116	901.6
Direct Load Control	$7,101,913		15,467,850	23,083.2
Time of Use Pricing	$1,333,934			6,076.1
Peak Time Rebates	$1,333,934			8,494.5
Subtotal	$60,984,778		1,057,855,286	87,216.6
Non-Residential Portfolio				
Prescriptive Rebates	$22,302,841		791,147,872	59,840.1
Custom Rebates	$13,957,683		313,852,249	16,649.6
Direct Load Control	$1,101,392		3,336,438	4,898.4
Time of Use Pricing	$1,333,934			4,107.5
Critical Peak Pricing	$1,333,934			5,029.0
Subtotal	$40,029,784		1,108,336,559	90,524.6
Education and Outreach				
Education and Outreach	$11,759,324	$500,000		
Infrastructure Enhancements				
Home Energy Display	*	*	308,650,344	
Smart Grid	*	*	54,110,000	5,300.0
	$0	$0	362,760,344	5,300.0
Other				
Evaluation Measure & Verif.	$5,663,694			
Total	$118,437,580	$500,000	2,528,952,189	183,041.2

*The costs of these initiatives are supported in *DP&L's Advanced metering Infrastructure Plan* and *DP&L's Smart Grid Development Plan.*

2 Process of Program Selection

2.1 Overview

DP&L set out to develop its Plan according to the following guiding principles:

- The Plan must be relevant for all customer classes.
- The initial suite of programs should be modeled after programs proven to be effective at other utilities across the nation. DP&L should first leverage lessons learned by other utilities before embarking on more complex programs.
- The program suite should provide a reasonable opportunity to meet the targets for energy and peak demand reduction set in R.C. Section 4928.66.

The Company did not engage in primary engineering studies to determine the theoretical potential of specific efficiency measures; instead, we drew the initial list of measures from leading utilities with similar climate and economic profiles across the nation. This decision was based on the preference to initially utilize funds directly toward energy efficiency programs (such as incentives) rather than on extensive research. Over time, DP&L will revise the individual programs and the suite of programs based on program performance and customer feedback. In the future we may revisit the topic of primary engineering studies and engage an engineering firm to uncover new or innovative opportunities unique to our service territory.

DP&L conducted a three-phased screening process to develop its proposed suite of programs.

- ***Review of Best Practices.*** The Company thoroughly reviewed best-practice energy efficiency and demand response programs from across the nation.
- ***Customer Research.*** Best-practice programs were tested with DP&L residential and non-residential customers to determine local relevance and estimated participation levels.
- ***Cost Effectiveness Screen.*** All short-listed measures were tested for cost effectiveness using the Total Resource Cost test (TRC) as defined by the *California Standard Practice Manual.*

2.2 Review of Best Practices

An initial list of EE and DR program options was developed from a review of the most successful programs at other utilities across the nation. Programs were evaluated based on energy conservation achieved, peak demand reduction and relevance to the DP&L market.

The programs evaluated were drawn from a review of a number of well-respected assessments of program best practices such as The American Council for an Energy Efficient Economy's (ACEEE) "Compendium of Champions: Chronicling Exemplary Energy Efficient Programs from Across the U.S."[1] and reviews of program best practices sponsored by the California Public Utilities Commission and the Energy Trust of Oregon. The initial list is also based on a review of the types of programs implemented by utilities often considered to be leaders in the field such as Xcel Energy, Northeast Utilities, Pacific Gas & Electric, and the Wisconsin Focus on Energy. Programs were excluded from consideration if it was determined that their success was dependent upon specific local circumstances such as weather patterns, high energy prices, or extremely high or low public concern about the environment.

A small set of programs consistently emerged as highly effective in most regional, price, and regulatory contexts. These programs were used as the baseline set of programs that were reviewed by a cross-functional project team, tested with customers, and analyzed for cost effectiveness. Table 2.2.d outlines the best-performing programs by customer segment.

[1] *ACEEE Compendium of Champions: Chronicling Exemplary Energy Efficient Programs from Across the U.S* February 2008

Table 2.2.d. Best Performing Programs by Customer Segment

Category	Program/Program Category
Residential	Manufacturer buydown and marketing/ promotion of Energy Star ™ CFLs Incentives for HVAC tune-up and efficient replacement. Including training of local vendors Rebates for energy efficient appliances Direct Load Control utilizing either programmable thermostats or switch devices Peak Time Rebates
Small C&I	Lighting and HVAC retrofit incentives
Large C&I	Prescriptive Lighting Prescriptive HVAC Prescriptive Motors Custom Incentives

2.3 Customer Research

A short list of programs with the best track records was analyzed in depth to determine which would be most effective for DP&L. Five rounds of customer research were conducted to determine the optimal suite of programs and to estimate participation rates for selected programs. Interviews, focus groups, and surveys focused on the following:

- Identifying customers and customer segments with the highest opportunity for energy conservation or peak reduction opportunities.
- Gauging interest/relevance of measures and programs.
- Estimating participation rates in narrowed list of programs.
- Testing price points to set incentives.

Table 2.3.a. provides an overview of DP&L's customer research efforts.

Table 2.3.a. Customer Research

Round	Date	Description
One	August 2007	Survey of 300 residential customers
Two	July-October 2007	Interviews with large C&I and public assembly customers Hospital focus group Small industrials focus group
Three	March – April 2008	Survey of 300 residential customers
Four	March-April 2008	Survey of 100 small C&I customers (10-50KW)
Five	March-April 2008	Survey of 200 medium C&I customers (50-300KW)

2.4 Cost Effectiveness Testing

All proposed programs were screened to ensure that they passed the Total Resource Cost (TRC) test as defined by the *California Standard Practice Manual*.

2.4.1 Total Resource Cost Test

Definition[2]

The Total Resource Cost test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The test is applicable to conservation, load management, and fuel substitution programs.

The benefits calculated in the Total Resource Cost test are the cost of avoided supply and the reduction in transmission and generation capacity, all valued at the marginal cost for the period the load reduction is expected to be achieved.

The costs in this test are the total program costs (paid out by the utility and/or the participants) plus the increase in supply costs for the periods in which load is increased (in the case of load shifting). Thus all costs associated with equipment, installation, operation and

[2] CPUC. *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.* October 2001

maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

Formulas

The formula for the benefit-cost ratio (BCRTRC) is presented below:

BCRTRC = BTRC /CTRC

Where:

BCRTRC = Benefit-cost ratio of total costs of the resource

BTRC = Benefits of the program

CTRC = Costs of the program

UACat = Utility avoided supply costs

UICt = Utility increased supply costs

PAC = Participant avoided supply costs

PRC = Utility program costs

PCN = Net participant costs

The B_{TRC} C_{TRC} terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

Net to Gross Ratio

The product of per-unit measure savings and the number of measures adopted (governed by the program participation rates) yields an estimate of annual gross savings. These savings must be adjusted to reflect two phenomena:

- Free Riders: Some customers who participate in a program (i.e., receive incentives for participation) would have installed the measures for which they received the incentives even in the absence of the program. These customers are known as "free riders" and the savings that result from their actions must be subtracted from gross savings.
- Spillover effect: Some customers are influenced to install measures for which program incentives are available, but do not take advantage of such incentives. This is known as the "spillover" effect. A combination of program advertising, changes in the product mix of retailers and trade allies as a result of programs, and word-of mouth can lead to customers investing in energy efficiency without being prompted by program incentives. Savings associated with the spillover effect should be added to gross savings.

The combined effect of free-ridership and spillover is reflected in what is called a "net-to-gross" ("NTG") ratio, a factor that is applied to an estimate of gross savings to derive the net level of savings that can be attributed to a program. The analysis of program cost effectiveness is based on net program savings estimated using NTG ratios included in the California Database of Energy Efficiency Resources ("DEER"). These ratios are based on over a decade of evaluated program impacts, are the most consistent set of such data available and are generally accepted in the industry.

2.4.2 Methodology

Utility and Participant Costs

Measure Savings and Costs

The key source of data for DP&L's analysis of energy efficiency measures was the DEER maintained by the California Energy Commission. This database is recognized as the most comprehensive and consistent database of such measures and is regularly updated. Energy efficiency measure savings, and costs for measures not affected by local climate, were taken in most cases directly from this database. The savings associated with a few measures, however, are affected by local climate and are therefore weather-sensitive. For example, the savings associated with an efficient central air conditioner is directly related to the number of cooling degree-days experienced in a particular area. Savings associated with these measures were estimated using data reported by other utilities in similar geographic regions. See WPG-1.18 for detailed TRC data by measure.

Administration and Evaluation Costs

These costs include all the costs incurred to operate the programs including marketing, administration, measurement and evaluation. Cost estimates were based on experience at other utilities.

Participation Rates

Participation rates for each program were estimated based in part on other utility program experience and on DP&L's assessment of reasonable levels of participation given the composition of its market. DP&L conducted extensive customer research to develop sound assumptions regarding participation in each program. See Table 2.3.a for a description of the five phases of research.

Economic Benefits

Value of Avoided Energy and Capacity

DP&L obtained avoided energy and capacity costs using power market forward prices. Estimated energy and demand savings were broken into 24 pricing periods corresponding to

monthly and on- or off-peak as defined by PJM. In order to allocate program savings to price period, DP&L leveraged both end-use load curve information from the Bridge Strategy Group as well as load shape data available from DP&L customers with interval meters. These customers represent industries which collectively account for most of DP&L's non-residential demand.

DP&L used the load shapes resulting from the aforementioned analysis to allocate the avoided energy and capacity associated with each efficiency measure. The market values were then applied to these volumes to determine the avoided costs per measure.

Ratio Calculation

The present value of both the stream of costs and benefits was calculated using DP&L's Weighted Average Cost of Capital (WACC), supported in Schedule D-1, to discount the cash flows. The incremental cost of the efficiency measures was considered to be a first-year cost, while avoided costs are expected to continue over the life of the measure. By comparing the present value of the benefits over the present value of costs, DP&L evaluates programs to determine which programs are cost-effective under the TRC test. See Table 2.4.a for a listing of the TRC test results by program.

Table 2.4.a Program TRC Results

Residential Lighting	4.9
Residential HVAC Tune-up	1.5
Residential HVAC Rebate	1.2
Residential Appliance Recycling	2.0
Residential Appliance Rebate	3.3
Residential Direct Load Control	1.8
Non-Residential Prescriptive Rebates	3.9
Non-Residential Custom Rebates	2.7
Non-Residential Direct Load Control	2.4

3 Programs

3.1 Residential Portfolio

3.1.1 Residential Lighting

Description

This program is designed to increase the number of Energy Star qualified compact fluorescent lamp (CFL) bulbs sold by providing incentives to decrease consumer costs. The program also will to increase consumer awareness and acceptance of energy-efficient lighting technology. The program will have an educational component to promote use, and proper disposal of, CFL bulbs.

Target Market

This program is designed for residential customers who purchase bulbs through retail channels. All customers taking delivery service from DP&L are eligible for this program regardless of their choice of supplier.

Implementation Plan

DP&L and implementation partners selected through an RFP process will negotiate discounts with bulb manufacturers, establish partnerships with retailers and/or their suppliers, oversee the implementation of cooperative advertising, audit retail outlets to confirm appropriate promotions are being implemented, and track the number of bulbs purchased and recycled.

Marketing Plan

The program will utilize customer incentives such as in-store instant rewards to encourage bulb procurement. The campaign may incorporate the annual Energy Star "Change a Light" campaign and will include cooperative advertising, point-of-purchase displays and retail education. Customers will learn of the program through bill stuffers, the enhanced website and

other public education and outreach activities. The incentives and marketing strategy will change based on response, market prices and manufacturer/distributor co-funding.

Annual Savings per Participant

Measure impacts of 47 kWh and 0.004 kW per bulb have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of CFLs	501,663	604,425	606,493	608,570	610,651	612,742	614,839

Estimated Budget

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$1,203,490	$1,664,586	$1,724,260	$1,786,762	$1,850,883	$1,917,882	$1,986,545
Marketing & Admin	$794,303	$1,098,627	$1,138,012	$1,179,263	$1,221,583	$1,265,802	$1,311,120
Total Costs	$1,997,793	$2,763,213	$2,862,272	$2,966,025	$3,072,466	$3,183,684	$3,297,665

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	23,578	28,408	28,505	28,603	28,701	28,799	28,897
Incremental Demand Savings (MW)	2.0	2.4	2.4	2.4	2.4	2.5	2.5

Total Resource Cost Test

The initial TRC test resulted in a ratio of 4.9.

3.1.2 Residential HVAC Diagnostic & Tune-Up

Description

This program is designed to obtain energy and demand savings by increasing the efficiency of residential central air conditioners. Under this program, DP&L will pay a portion of the cost of specific diagnostic and tune-up services performed by HVAC contractors that are certified by a third party to perform such tune-ups. Among other points, the tune-up will verify the unit's refrigerant charge and air flow.

Target Market

This program is designed for residential customers with central air conditioning units in owner-occupied, single-family residential dwellings. All targeted customers taking delivery service from DP&L are eligible for this program regardless of their choice of supplier.

Implementation Plan

Channel partners must undergo training and certification provided by an approved third party prior to being able to provide this service to DP&L's customers under this program. Customers may schedule appointments directly with the approved HVAC contractors and DP&L will pay a $100 incentive after completion of the HVAC tune-up. This incentive is available for a qualifying account every three years.

Marketing Plan

The program will utilize cooperative advertisements with certified contractors as well as promotion through DP&L Call Center personnel, bill stuffers, telemarketing, DP&L's enhanced website and other public education and outreach activities. The incentives and marketing strategy will change based on response and market prices.

Annual Savings per Participant

Measure impacts of 394 kWh and 0.35 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of Tune-ups	5,288	7,521	7,546	7,572	7,598	7,624	7,650

Estimated Budget

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$528,800	$776,543	$804,479	$833,450	$863,513	$894,600	$926,798
Marketing & Admin	$264,400	$388,272	$402,240	$416,725	$431,757	$447,300	$463,399
Total Costs	$793,200	$1,164,815	$1,206,719	$1,250,175	$1,295,270	$1,341,900	$1,390,197

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	2,083	2,963	2,973	2,983	2,994	3,004	3,014
Incremental Demand Savings (MW)	1.9	2.6	2.6	2.7	2.7	2.7	2.7

Total Resource Cost Test

The initial TRC test resulted in a ratio of 1.5.

3.1.3 Residential HVAC Rebates

Description

There are substantial energy efficiency and demand reduction opportunities associated with the proper sizing and installation of new central HVAC systems, as well as with the installation of premium efficiency equipment. This program provides a rebate to qualifying customers that serves to pay a portion of a new HVAC unit.

Target Market

This program is designed for any homeowner or landlord purchasing an HVAC unit that will be installed at a residence within the DP&L service territory. All targeted customers taking delivery service from DP&L are eligible for this program regardless of their choice of supplier.

Implementation Plan

DP&L will partner with HVAC contractors that become certified to participate in the program and sign a partnership agreement. Contractor incentives will be provided for documented installations that meet the requirements. DP&L anticipates paying an average of $168 per central HVAC system from 2009 through 2015.

Marketing Plan

The program will take advantage of replacement opportunities identified through the HVAC Diagnostic & Tune-Up program. It will also utilize cooperative advertisements with certified contractors as well as promotion through DP&L Call Center personnel, bill stuffers, telemarketing, DP&L's enhanced website and other public education and outreach activities. The incentives and marketing strategy will change based on response and market prices.

Annual Savings per Participant

Measure impacts of 280 kWh and 0.25 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of Systems	2,299	5,998	6,019	6,039	6,060	6,081	6,101

Estimated Budget

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$347,149	$935,148	$968,939	$1,003,742	$1,039,957	$1,077,492	$1,116,178
Marketing & Admin	$243,004	$654,604	$678,257	$702,619	$727,970	$754,244	$781,325
Total Costs	$590,153	$1,589,752	$1,647,196	$1,706,361	$1,767,927	$1,831,736	$1,897,503

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	644	1,679	1,685	1,691	1,697	1,703	1,708
Incremental Demand Savings (MW)	0.6	1.5	1.5	1.5	1.5	1.5	1.5

Total Resource Cost Test

The initial TRC test resulted in a ratio of 1.2.

3.1.4 Residential Appliance Recycling

Description

The program is designed to promote the retirement and recycling of inefficient appliances from households by offering a turn-in incentive for working equipment as well as information and education on the cost of keeping an inefficient unit in operation. DP&L will provide an incentive of $50 for the removal of an inefficient second refrigerator or freezer and an incentive of $25 for the removal of an inefficient window air conditioner. DP&L will also fund the removal and arrange the appropriate recycling for the inefficient units. DP&L may revise the list of eligible appliances based on current market conditions, technology developments and program implementation experience.

Target Market

This program is designed for residential customers with working inefficient room air conditioners and working second refrigerators or freezers. All targeted customers taking delivery service from DP&L are eligible for this program regardless of their choice of supplier.

Implementation Plan

DP&L will work with a third party that will remove the qualifying unit, arrange for the appropriate recycling and provide to DP&L the customer information to facilitate the rebate. The vendor(s) will be selected through an RFP process.

Marketing Plan

There will be a strong consumer marketing and education component emphasizing the cost of operating an inefficient room air conditioner, second refrigerator or freezer. The advertising campaign will also promote the availability of program incentives.

Annual Savings per Participant

Measure impacts of 1,707 kWh and 0.27 kW has been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of Appliances	920	1,846	2,315	2,323	2,331	2,339	2,347

Estimated Budget

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$44,151	$91,469	$118,435	$122,701	$127,133	$131,709	$136,455
Marketing & Admin	$97,132	$201,232	$260,557	$269,942	$279,693	$289,760	$300,201
Total Costs	$141,283	$292,701	$378,992	$392,643	$406,826	$421,469	$436,656

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	1,570	3,151	3,952	3,965	3,979	3,993	4,006
Incremental Demand Savings (MW)	0.2	0.5	0.6	0.6	0.6	0.6	0.6

Total Resource Cost Test

The initial TRC test resulted in a ratio of 2.0.

3.1.5 Residential Appliance Rebate

Description

This program is designed to increase the sales of Energy Star qualified ceiling fans, room air conditioners, dishwashers, freezers and dehumidifiers through rebates.

Target Market

Residential customers of existing and new homes within the DP&L service territory, regardless of their choice of energy supplier.

Implementation Plan

The delivery strategy will focus on generating participation from appliance retailers within DP&L's service territory, and participating customers will mail in the appropriate information to receive a rebate. DP&L expects to partner with a fulfillment party to contact appliance outlets and to generate the customer refunds. DP&L anticipates paying an average of $30 per appliance from 2009 – 2015.

Marketing Plan

The program will utilize cooperative advertisements with appliance retailers as well as promotion through DP&L Call Center personnel, bill stuffers, DP&L's enhanced website and other public education and outreach activities. The incentive and marketing strategy will change based on response and market pricing.

Annual Savings per Participant

Measure impacts of 207 kWh and 0.19 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	[illegible]	[illegible]
Number of Appliances	2,759	3,691	4,630	4,646	4,661	4,677	4,693

Estimated Budget

Budget Category	Year 1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incentive Costs	$73,638	$101,724	$131,770	$136,499	$141,368	$146,484	$151,772
Marketing & Admin	$44,183	$61,034	$79,062	$81,899	$84,821	$87,890	$91,063
Total Costs	$117,821	$162,758	$210,832	$218,398	$226,189	$234,374	$242,835

Estimated kW and kWh Savings

Savings	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incremental Energy Savings (MWh)	571	764	958	962	965	968	971
Incremental Demand Savings (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Total Resource Cost Test

The initial TRC test resulted in a ratio of 3.3.

3.1.6 Residential Low Income Affordability

Description

Low-income electric customers meeting the program guidelines may undergo an energy audit where the auditor will review the energy efficiency of the home and provide feedback on areas of improvement. The auditor will then work with the customer to create a mutually beneficial plan for improving the energy efficiency of the home. Those electric solutions that are found to have a benefit / cost ratio better than 1.0 will be funded through this program. The expected types of solutions include efficient lighting; refrigerator, freezer and/or window A/C replacements; HVAC tune-ups and/or replacements, caulking, insulation and education. The cost of the efficiency solutions funded through this program can be a maximum for any single family home of $5,000, and a multi-family home of $50,000.

Target Market

This program is available to low-income residential electric customers within the DP&L service territory with household incomes up to 200% of the federal poverty level. Eligible households include single-family homes and multi-family homes where 80% of the tenants meet the income requirements of the program. This program is available to all qualifying electric customers taking delivery service from DP&L, regardless of their choice of supplier.

Implementation Plan

DP&L will partner with local non-profit agencies to bring low-income customers the benefits of this program. The Department of Energy Home Weatherization Assistance Program, the Ohio Electric Partnership Program (EPP) and the Community Action Partnership (CAP) agencies have been involved in energy efficiency activities for years. Through this new program DP&L will help to fund the agencies, audits and solutions to expand the reach of these programs and help to make electricity more affordable to the qualifying low-income customers within the Company's service territory.

Marketing Plan

The partner agencies will promote the programs through their daily interactions with qualifying customers. Agencies are normally limited to serving customers with incomes up to 180% of the federal guidelines. DP&L's program will add an additional tool for the agencies that expands their breadth of services to the equally at-risk population between 180% - 200% of the federal poverty guidelines. Additionally, DP&L Call Center personnel will educate qualified customers about the program, and information about this program will be posted on DP&L's website and provided in an annual bill stuffer.

Annual Savings per Participant

Measure impacts of 1,999 kWh and 0.151 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of Customers	853	853	853	853	853	853	853

Estimated Budget (in thousands of dollars)

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$789,025	$814,666	$841,143	$868,482	$896,708	$925,855	$955,949
Marketing & Admin	$210,265	$217,097	$224,151	$231,436	$238,959	$246,722	$254,740
Total Costs	$999,280	$1,031,763	$1,065,294	$1,099,918	$1,135,667	$1,172,577	$1,210,689

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	1,705	1,705	1,705	1,705	1,705	1,705	1,705
Incremental Demand Savings (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Total Resource Cost Test

Due to the charitable nature of the program DP&L did not perform a TRC test for this program.

3.1.7 Residential Direct Load Control

Description

The Direct Load Control program provides eligible participants with a programmable thermostat that is installed at no cost, and can be programmed via the internet. During peak summer conditions or periods of regional operating constraints, DP&L can signal the thermostat to cycle the air conditioner on and off, which will reduce load on DP&L's system and result in a temperature increase of only a few degrees Fahrenheit.

Target Market

This program targets residential customers within the DP&L service territory who have central air conditioning. This program is available to all qualifying electric customers taking delivery service from DP&L, regardless of their choice of supplier.

Implementation Plan

DP&L plans to finalize the specific terms and conditions of the program in 2009 to begin implementing the program in the summer of 2010 for customers who have advanced meter infrastructure in place. Based on the success of this effort, DP&L intends to make this service available to all residential customers with advanced metering infrastructure commencing the summer of 2011. DP&L anticipates that it will pay $324 per household to install a programmable thermostat from 2010 through 2015.

DP&L will choose a qualified implementation partner through an RFP process. The selected vendor(s) or contractor(s) will work with DP&L to deliver services to the area. Elements or the vendor's role may include customer recruitment, thermostat installation, demand response implementation, and quality control inspection.

Marketing Plan

Recruitment of eligible customers will occur through bill stuffers, website communication, public education and outreach activities, and possibly through initiatives undertaken by an implementation partner.

Annual Savings per Participant

Measure impacts of 369 kWh and 1.38 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of New Thermostats Installed	0	288	1,250	2,323	3,496	4,677	4,693

Estimated Budget (in thousands of dollars)

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Thermostats	$0	$98,911	$441,175	$724,706	$1,109,456	$1,509,876	$1,542,167
Thermostat Maintenance	$0	$4,946	$27,141	$60,226	$116,737	$194,247	$274,833
Marketing & Admin	$0	$189,504	$201,438	$105,302	$189,623	$175,388	$136,238
Total Costs	$0	$293,361	$669,754	$890,234	$1,415,816	$1,879,511	$1,953,238

Estimated kW and kWh Savings

Incremental Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	-	107	463	860	1,294	1,730	1,736
Incremental Demand Savings (MW)	-	0.4	1.7	3.2	4.8	6.5	6.5

Total Resource Cost Test

The initial TRC test resulted in a ratio of 1.8.

3.1.8 Residential Time-of-Use Pricing

Description

The Time-of-Use Pricing tariff encourages participating customers to shift electric usage from peak to off-peak hours, particularly during the summer season. The time-of-use rates will be designed so that the price per kWh during the peak summer season will be higher during the peak hours and lower during the off-peak hours. Those customers who reduce consumption during peak periods or who switch their consumption to off-peak hours should see a lower annual energy bill.

Target Market

This program is available to all residential customers taking delivery service from DP&L who elect to purchase transmission and generation service from DP&L.

Implementation Plan

Prior to 2011, DP&L will conduct the rate design studies needed to establish the revenue-neutral prices and will determine the specific terms and conditions of the program, such as defining the applicable months as well as the on- and off-peak hours and rates. DP&L plans to offer the Time-of-Use Pricing program beginning in 2011 to customers that have advanced metering infrastructure in place. Based on the success of this effort, DP&L intends to make this service available to all residential customers with advanced metering infrastructure.

Marketing Plan

Recruitment of eligible customers will occur through bill stuffers, website communication, public education and outreach activities, and possibly through initiatives undertaken by an implementation partner.

Annual Savings per Participant

An average impact of 0.40 kW has been used for planning purposes. DP&L currently assumes no energy savings from this program, as the emphasis is on shifting electric consumption.

Estimated Participation

Participation	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incremental Participants	0	0	313	0	3,846	5,145	5,163

Estimated Budget (in thousands of dollars)

Budget Category	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Marketing & Admin	$0	$0	$250,000	$258,125	$266,514	$275,176	$284,119
Total Costs	$0	$0	$250,000	$258,125	$266,514	$275,176	$284,119

Estimated kW and kWh Savings

Incremental Savings	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incremental Energy Savings (MWh)	0	0	0	0	0	0	0
Incremental Demand Savings (MW)	0.0	0.0	0.1	0.0	1.6	2.2	2.2

Total Resource Cost Test

A TRC test is not applicable for pricing arrangements.

3.1.9 Residential Peak Time Rebate Pricing

Description

The Peak Time Rebate rider gives customers a rebate per kWh for curtailing energy below a pre-established baseline projection during peak conditions. The amount of curtailed energy is based on actual consumption during the applicable hours compared with a customer's baseline, which is calculated as the average energy consumed during comparable days preceding the day of peak conditions. Customers will receive advanced notification of a peak event, which will occur only on a weekday during the summer period.

Target Market

This program is targeted towards all residential customers taking delivery service from DP&L. This program is available to all qualifying electric customers, regardless of their choice of supplier or DP&L tariff option.

Implementation Plan

Prior to 2011, DP&L will conduct the rate design studies needed to establish the refund value and will determine the specific terms and conditions of the program, such as how the customer-specific baseline calculation will be conducted. DP&L will introduce the Peak Time Rebate program beginning in 2011 to customers who have advanced metering infrastructure in place. Based on the success of this effort, DP&L intends to make this service available to all residential customers with advanced metering infrastructure.

Marketing Plan

Recruitment of eligible customers will occur through bill stuffers, website communication, public education and outreach activities, and possibly through initiatives undertaken by an implementation partner.

Annual Savings per Participant

An average impact of .37 kW has been used for planning purposes for Peak Time Rebates. DP&L currently assumes no energy savings from this program, as the emphasis is on shifting electric consumption.

Estimated Participation

Participation	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incremental Participants	0	0	313	0	6,153	8,232	8,260

Estimated Budget (in thousands of dollars)

Budget Category	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Marketing & Admin	$0	$0	$250,000	$258,125	$266,514	$275,176	$284,119
Total Costs	$0	$0	$250,000	$258,125	$266,514	$275,176	$284,119

Estimated kW Savings

Incremental Savings	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Incremental Demand Savings (MW)	0.0	0.0	0.1	0.0	2.3	3.0	3.1

Total Resource Cost Test

A TRC test is not applicable for pricing arrangements.

3.2 Non-Residential Portfolio

3.2.1 Non-Residential Prescriptive Rebates

Objective

The Non-Residential Prescriptive Rebates program is designed to provide a simple set of solutions for non-residential customers that wish to become more energy efficient. The initial set of solutions and corresponding incentive rebates (as contained in WPG-1.10a) represents proven products that provide energy savings over the standard products in each category. Rebate amounts are determined based on cost effectiveness and will not exceed 50% of the measure cost. The rebate listing will be available on DP&L's website and will be updated periodically to account for new and improving technologies. DP&L does not envision placing a cap on the amount that a customer may receive under this program.

Target Market

This program is designed for all non-residential customers seeking to improve the energy efficiency of their new and existing facilities within the DP&L service territory. The program may be utilized by all non-residential customers regardless of their choice of energy supplier. Approximately sixty percent of DP&L's non-residential customers fall into the segments of office space, retail and manufacturing. Therefore, specific outreach efforts will be directed to these segments.

Eligible Measures

Initially DP&L will offer incentives for an array of efficient technologies, including lighting, HVAC, motors and drives, and compressed air. A listing of the specific measures included in this program is found in WPG-1.10a. DP&L reserves the right to modify this set of measures and incentives.

Implementation Plan

Upon completion of a qualifying project, the customer will file a rebate application, which will identify the measure taken and document the project's costs. DP&L's marketing efforts for this program will focus heavily on educating channel partners about the incentive program and the qualifying measures. A random sampling of applications and every rebate application over $10,000 will be subject to on-site verification prior to any payment being made.

Marketing Plan

DP&L's marketing efforts for this program will focus heavily on educating channel partners about the incentive program and the applicable measures. DP&L will also market this program directly to non-residential customers using bill stuffers, a dedicated section DP&L's enhanced website, direct customer contact, and other outreach activities. In addition to these activities, the utility will focus specific efforts on reaching its key non-residential customer segments, which account for significant load and savings opportunities. The incentives and marketing strategy will change based on customer response, market prices and manufacturer/distributor co-funding.

Estimated Participation

Participation estimates by measure and year can be found in WPG-1.10a.

Estimated Budget (in thousands of dollars)

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$1,305,904	$1,590,031	$1,897,646	$2,268,886	$2,719,210	$2,807,580	$2,896,827
Marketing & Admin	$574,598	$699,614	$834,964	$998,310	$1,196,452	$1,235,335	$1,275,484
Total Costs	$1,880,502	$2,289,645	$2,732,610	$3,267,196	$3,915,662	$4,042,915	$4,174,311

Estimated kW and kWh Savings

Energy Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental MWh	20,454	24,140	28,223	32,868	38,423	38,423	38,423
Incremental MW	5.5	6.5	7.6	8.9	10.4	10.4	10.4

Total Resource Cost Test

The initial TRC test resulted in a ratio of 3.9.

3.2.2 Non-Residential Custom Rebates

Description

This program provides financial assistance to non-residential customers to support implementation of efficiency opportunities available for new equipment purchases, facility modernization and industrial process improvement. The incentive will be calculated based on expected demand and energy savings. As an optional part of the program, DP&L will establish an audit program to assist customers in evaluating the energy efficiency opportunities available to them.

Target Market

This program is targeted to existing non-residential customers with cost-effective efficiency opportunities that do not qualify for prescriptive rebates, but nonetheless provide efficiency opportunities that are worthy of implementing. This program is available to qualifying customers taking delivery service from DP&L regardless of their choice of supplier.

Implementation Strategy

The program will employ both incentive reservation and application stages. Prior to undertaking a project, applicants must submit a rebate reservation form that provides all data necessary to determine an incentive level. The Company will review the reservation and verify the incentive. For large projects, DP&L reserves the right to perform a site visit to verify baseline conditions. If approved, DP&L will reserve the incentive amount and approve the level of funding to support the project. Upon completion of the project, the customer will file a rebate application, which will be similar to the reservation application but will also require documentation of project costs. On-site verification prior to any payment will be performed for both a random sampling of applications and every rebate application over $10,000.

DP&L's marketing efforts for the custom rebate program will focus heavily on educating trade allies about the incentive program. In addition to these activities, the utility will focus specific efforts on reaching the key non-residential customer segments mentioned earlier, which

account for significant load and savings opportunities. Finally, DP&L anticipates making audits available to non-residential customers to identify energy efficiency opportunities.

Marketing Strategy

DP&L's marketing efforts for the custom rebate program will focus heavily on educating trade allies about the incentive program. In addition to these activities, DP&L will focus specific efforts on reaching its key non-residential customer segments, which account for significant load and savings opportunities. The program will also be promoted to non-residential customers using bill stuffers, a dedicated section of DP&L's enhanced website and other outreach activities.

Estimated Participation

Participation will be based upon the number of projects approved.

Estimated Budget

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incentive Costs	$261,311	$1,091,540	$1,412,458	$1,470,575	$1,528,851	$1,589,020	$1,651,202
Marketing & Admin	$143,721	$600,347	$776,852	$808,816	$840,868	$873,961	$908,161
Total Costs	$405,032	$1,691,887	$2,189,310	$2,279,391	$2,369,719	$2,462,981	$2,559,363

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	2,903	11,746	14,721	14,844	14,946	15,046	15,143
Incremental Demand Savings (MW)	0.5	2.2	2.7	2.8	2.8	2.8	2.8

Total Resource Cost Test

The initial TRC test resulted in a ratio of 2.7.

3.2.3 Non-Residential Direct Load Control

Description

The Direct Load Control program provides eligible participants with a programmable thermostat that is installed at no cost, and can be programmed via the internet. During peak summer conditions or periods of regional operating constraints, DP&L can signal the thermostat to cycle the air conditioner on and off, which will reduce load on DP&L's system and result in a temperature increase of only a few degrees Fahrenheit.

Target Market

This program targets small non-residential customers within the DP&L service territory that have central air conditioning units. This program is available to all qualifying electric customers taking delivery service from DP&L, regardless of their choice of supplier or DP&L tariff option.

Implementation Strategy

DP&L plans to finalize the specific terms and conditions of the program in 2009 and to introduce the program beginning the summer of 2010 to customers that have advanced meter infrastructure in place. Based on the success of this effort, DP&L intends to make this service available to all residential customers with advanced metering infrastructure commencing the summer of 2011.

DP&L will choose a qualified implementation partner through an RFP process. The selected vendor(s) or contractor(s) will work with DP&L to deliver services to the area. Elements of the vendor's role include customer recruitment, thermostat installation, demand response implementation, and quality control inspection.

Marketing Strategy

Recruitment of eligible customers will occur through bill stuffers, website communication, public education and outreach activities, and possibly through initiatives undertaken by an implementation partner.

Annual Savings per Participant

Measure impacts of 517 kWh and 1.93 kW have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Number of New Thermostats Installed	0	80	183	343	520	702	710

Estimated Budget (in thousands of dollars)

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Thermostats	$0	$27,475	$64,588	$107,006	$165,022	$226,627	$233,313
Thermostat Maintenance	$0	$1,374	$4,641	$9,453	$17,867	$29,507	$41,701
Marketing & Admin	$0	$52,640	$29,490	$15,548	$28,205	$26,325	$20,611
Total Costs	$0	$81,489	$98,719	$132,007	$211,094	$282,459	$295,625

Estimated kW and kWh Savings

Incremental Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	0	41	95	178	269	364	368
Incremental Demand Savings (MW)	0.0	0.2	0.4	0.7	1.0	1.4	1.4

Total Resource Cost Test

The initial TRC test resulted in a ratio of 2.4.

3.2.4 Non-Residential Time-of-Use Pricing

Objective

The Time-of-Use rates encourage participating customers to shift electric usage from peak to off-peak hours, particularly during the summer peak season. The Time–of-Use rates will be designed so that the price per kWh during the peak summer season will be higher during the peak hours and lower during the off-peak hours. Those customers that are able to reduce consumption during peak periods or to shift their consumption to off-peak hours should see a lower annual energy bill. This program differs from the Residential Time-of-Use Pricing program in that non-residential customers may elect the Critical Peak Pricing (CPP) option, whereby the rate for power consumed on the off-peak hours is further reduced in exchange for a significantly higher rate during critical peak events. Customers will receive prior notification of a CPP event.

Target Market

This program is targeted towards all non-residential customers taking delivery service from DP&L that elect to purchase transmission and generation service from DP&L.

Implementation Strategy

Prior to 2011, DP&L will conduct the rate design studies needed to establish the revenue-neutral prices and will determine the specific terms and conditions of the program, such as defining the critical peak pricing differential. DP&L plans to introduce the Time-of-Use Pricing program beginning January, 2011 to customers that have advanced metering infrastructure in place. Based on the success of this effort, DP&L intends to make this service available in 2012 to all non-residential customers with advanced metering infrastructure.

Marketing Strategy

DP&L's marketing efforts will focus heavily on educating eligible customers about the program and may include bill stuffers, a dedicated section DP&L's enhanced website, direct customer contact, and other outreach activities. The marketing strategy will continue to be refined based on customer response.

Annual Savings per Participant

Measure impacts of 1.62 kW for Time of Use and 1.99 kW for Critical Peak Pricing have been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental TOU Participants	0	0	196	367	557	752	761
Incremental TOU CPP Participants	0	0	196	367	557	752	761

Estimated Budget (in thousands of dollars)

Budget Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Marketing & Admin	$0	$0	$500,000	$516,250	$533,028	$550,352	$568,238
Total Costs	$0	$0	$500,000	$516,250	$533,028	$550,352	$568,238

Estimated kW Savings

Based on benchmarking results DP&L estimates that the Time-of-Use Pricing program will provide the following demand savings. Since this rate option is expected to shift load rather than reduce it, there are no energy savings associated with this program.

Incremental Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental TOU Demand Savings (MW)	0.0	0.0	0.3	0.6	0.9	1.2	1.2
Incremental TOU CPP Demand Savings (MW)	0.0	0.0	0.4	0.7	1.1	1.4	1.5

Total Resource Cost Test

The TRC test is not applicable for pricing arrangements.

3.3 Education and Outreach Activities

3.3.1 Education/Awareness Building/Market Transformation Activities

Description

The program will use education and outreach activities as well as energy efficiency enhancements to the Company's website to educate customers, community leaders and children. The education and outreach activities will be targeted to schools, government leaders, civic organizations and local media. Significant enhancements will be made to the Company's website and will feature tools for conserving energy, custom applications that grant customers insights into the usage characteristics of their premises, as well as detailed information on DP&L's programs and participating channel partners.

Target Market

This program is designed for all customers taking delivery service from DP&L, regardless of their choice of supplier.

Implementation Strategy

The education and outreach activities will be performed by DP&L employees and selected channel partners. Additional features will be made available on DP&L's website once the appropriate systems are acquired and/or developed.

Marketing Strategy

The website enhancements will be promoted directly by DP&L's call center personnel and through direct marketing to the customers. The education and outreach campaign will utilize both a "push" and "pull" strategy, where DP&L employees will partner with local media, schools and various civic/governmental organizations to promote the education campaign and offer to make presentations. Through word-of-mouth advertising, we anticipate that we will also receive

requests from multiple individuals, corporations and organizations that were not initially targeted.

Estimated Budget

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Education & Outreach Costs	$1,635,000	$1,484,000	$1,619,625	$1,671,553	$1,726,063	$1,782,175	$1,840,908

3.4 Infrastructure Enhancements

3.4.1 Home Energy Display

Description

DP&L will provide customers with home energy displays that will provide information on current energy consumption and prices. The display may also receive and display signals regarding peak and/or critical peak pricing periods. While many customers will choose to get information on energy usage and pricing from DP&L's website portal available via the Internet, this home energy display will allow customers who do not have Internet access to obtain the same information.

Target Market

This program is designed for residential customers who have advanced metering infrastructure in place and do not have access to the internet; however, any residential customer may participate. All targeted customers taking delivery service from DP&L are eligible for this program regardless of their choice of supplier.

Implementation Plan

DP&L or one or more approved vendors will see that these devices are provided to customers who wish to participate.

Marketing Plan

The program will be promoted through DP&L Call Center personnel, bill stuffers, DP&L's enhanced website and other public education and outreach activities.

Annual Savings per Participant

A measure impact of 606 kWh has been used.

Estimated Participation

Participation	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
HED Devices	0	16,610	37,501	69,684	104,883	140,323	140,323

Estimated Budget

Costs are included as part of the AMI deployment.

Estimated kW and kWh Savings

Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Energy Savings (MWh)	0	10,066	12,660	19,503	21,331	21,477	0

3.4.2 Smart Grid

Description

The efficient placement of capacitor banks and regulators will maintain voltage and maximize the power factor along the feeder lines. This, coupled with the effective modeling of the distribution circuits will allow DP&L to reduce line losses on the distribution system.

Implementation Plan

The implementation plan is described in the *Smart Grid Development Plan* contained in this filing.

Estimated Budget

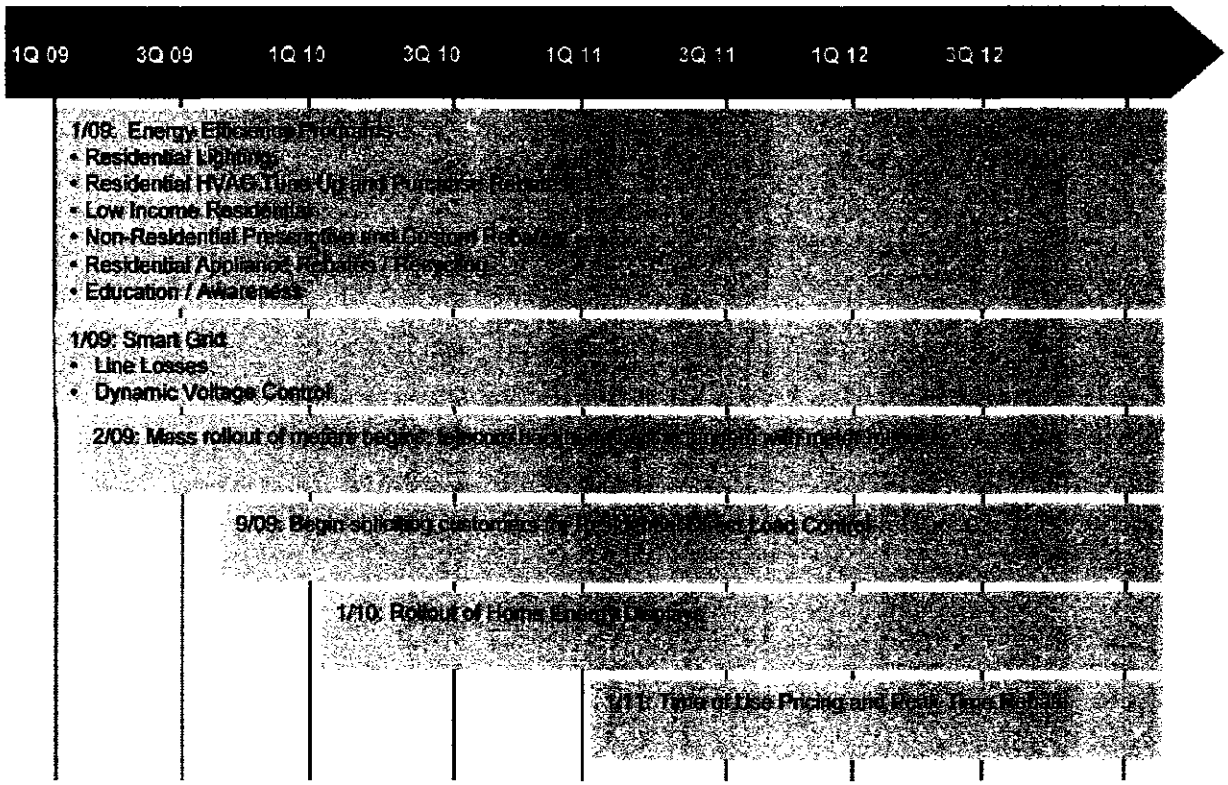
Costs are included as part of the smart grid deployment.

Incremental Savings	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Incremental Smart Grid Energy Savings (MWh)	1,405	1,418	1,263	1,422	1,418	1,413	16,684
Incremental Smart Grid Demand Savings (MW)	0.3	0.3	0.3	0.3	0.3	0.3	3.5

4 Rollout Plan

DP&L expects to launch programs beginning in January of 2009 subject to the availability of underlying infrastructure such as the advanced metering infrastructure for demand response programs and required billing capabilities for Time-of-Use rates. The proposed implementation schedule is based on current estimates of deployment of AMI and IT system upgrades but is subject to change based on the regulatory outcome and actual deployment dates.

Exhibit 4.1.a. Implementation Schedule



5 Program Evaluation & Modifications

5.1 Program Evaluation Plan

DP&L's team will estimate program savings, monitor program performance and ensure that incentives paid are proportionate with achieved savings. To aid in such Evaluation, Measurement and Verification (EM&V) activities, DP&L will select an independent program evaluation contractor through an RFP process to perform the following EM&V activities:

- Impact evaluations – determinations of program savings and cost-effectiveness.
- Process evaluation – assessments of the effect of program structure and how implementation has affected program performance.
- Verification – evaluate program participation, compliance with program terms and actual measure savings.
- Market effects studies – evaluate the extent to which a program has changed the way a market behaves.

5.2 Program Modifications

As the evaluation process and Company experience provides information on program effectiveness and customer participation, the Company plans to utilize those results to expand, revise or potentially discontinue individual programs. This flexibility will allow the Company to achieve the best mix of measures to provide customers with the greatest benefits and to meet the efficiency and demand reduction targets set out by R.C. Section 4928.6.

Chapter 3

The Dayton Power & Light Company's Advanced Metering Infrastructure Plan

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1 Introduction

1.1 AMI Overview

Advanced Metering Infrastructure (AMI) transforms the meter from a simple measuring and counting device, to one element of an integrated system of hardware, software, and people that can be used to better manage the electric service which customers find essential to their lives. AMI is not simply a tool to capture customer consumption of energy, but a hardware and software architecture capable of capturing real-time consumption, demand, voltage, current and other information. Data can be provided at the customer level and for other enterprise level systems either on a scheduled basis or on demand. A typical AMI network will communicate this data to a central location, sorting and analyzing it for a variety of purposes such as customer billing, outage response, system loading conditions and demand-side management. The AMI network will also send this information to other systems, customers and third parties, as well as send information back through the network and meters to capture additional data, control equipment, and update the configuration of the equipment and software load. This is the principal characteristic of what the industry calls a two-way communications network.

AMI introduces new functionality that will support DP&L's efforts to improve operations and provide greater value to its customers. The availability of near-real and/or real-time consumption data supports time-differentiated rates for customers. DP&L representatives will have access to more complete and current customer data when addressing customer concerns. Moreover, the interval data and accurate load shapes can be made available to customers to help them manage energy costs.

During outages, AMI will make it possible to recognize quickly and accurately service restoration needs, allowing improved crew dispatch, reduction in unneeded trips to customers whose service has already been restored and improve communications with customers and the community. The AMI system provides the ability to detect outages without customer call-ins. This may occur in several ways: some AMI systems are configured to enable the meter to send a "last gasp" signal notifying the utility that the meter has lost power; in other systems the AMI system controller listens continually to the meters and notifies the utility that an outage has occurred when the meter stops transmitting. More accurate information can result in more

effective load management activities, and the ability to analyze their impacts. This information can be used to improve load forecasts, hedging, and supply management, as well as distribution system and substation management and planning as the industry gains more experience using the capabilities of AMI.

1.1.1 Enhances Reliability

One of the primary reasons that DP&L is proposing the rollout of AMI is to enhance network reliability and system responsiveness. Only by building an AMI infrastructure can DP&L place sufficient emphasis and dedicate sufficient resources to meeting customers' expectations about the reliability of the electric distribution system.

AMI meters help to enhance reliability by providing:

- Real-time monitoring of the distribution network which allows for earlier outage detection;
- Enhanced ability to locate where an outage has occurred, allowing a utility to dispatch repair crews directly to the location;
- Improved verification of customer service restoration;
- Better control of activity over the distribution systems;
- Additional power quality information, such as voltage, VARs and power factor for residential and C&I customers, which are necessary for better tuning of the distribution network and voltage levels at the substations and regulators along the feeder.

DP&L and the Commission will need to work very closely together on a method to recalibrate some of the reliability metrics currently used once the AMI system is in place. The AMI system will enable DP&L to measure outages more accurately since customer reporting of the outages is no longer necessary. The measured number and length of outages may initially increase due to improved notification and measurement, even though reliability as experienced by customers is expected to improve.

1.1.2 Enables Demand Response

The proposed AMI system will help to minimize the cost of energy and to permit customers to access various demand response programs that improve system load factor and help to defer the construction of new facilities. AMI is a necessary enabling technology for the success of demand response for three primary reasons. First, AMI provides the reliable interval data necessary to measure and verify load reductions achieved by customers, individually and as groups. This allows the market to accurately value customer demand response and allows third parties (e.g., curtailment service providers) to develop demand response programs at a reasonable incremental cost.

Second, AMI provides information necessary for customers, individually and as groups, to determine the load impact of demand responses they might take. This allows customers to make intelligent decisions concerning their levels of participation in various demand response programs available today and in the future.

Third, AMI provides a platform to engage customers in demand response activities. Time-based pricing programs can be tailored carefully and precisely with AMI. Customers can be notified in their homes or businesses when demand response would save them the most money. Prices and financial incentives can target specific outcomes (e.g., peak load reduction for reliability purposes, reduction of peak energy prices, control of local peak loads that may stress the distribution system). Optional load control measures (e.g., home area networks, or chips in the meter that can manage the operation of individual appliances) can help customers optimize their participation in demand response programs without reducing the benefits and value of those appliances to the customer.

The full benefits of demand response cannot be achieved unless the Company is able to implement new programs that encourage load shifting, curtailment and other features. Such programs are part of DP&L's integrated filing and details of those programs are provided in *The Dayton Power and Light Company Energy Efficiency and Demand Response Plan.*

1.1.3 Foundation for Smart Grid

Most utilities consider the implementation of an AMI system to be the fundamental enabling component of the smart grid. Much of the customer benefit of a smart grid

infrastructure relies on the capture of detailed data, timely enough to communicate the status of the utility distribution system to process-intelligent controls for the distribution equipment. AMI can potentially capture meter-level activities and data for smart grid applications, for example:

- SCADA voltage telemetry data at feeder breakers in the substations can indicate the quality of the power supply to the distribution network, but voltage information at service transformers and customer delivery points is necessary to discern circuit or transformer level problems for more effective Volt/VAR control.
- Substation breaker and reclosure operations can be used to evaluate the scale of an outage, but meter-level outage and restoration notification events are necessary to optimize outage restoration efforts.
- Emergency load response activities such as load shedding can alleviate potentially catastrophic system concerns, but at a significant cost to customer satisfaction and company image. Demand response information distributed to the individual premise allows utilities to achieve expected load reductions without sacrificing customer satisfaction.

Implementation of a meter data management system (MDMS) and integration of AMI data with distribution management systems (DMS), outage management systems (OMS), and other systems provide the information and intelligent control necessary to facilitate the operation of the smart grid. A smart grid proposal is included as part of DP&L's integrated filing and details of our smart grid plan are provided in *The Dayton Power and Light Company Smart Grid Development Plan.*

1.2 Executive Summary of AMI Plan

1.2.1 Summary AMI Plan

DP&L expects to spend $255.0M in capital and $63.1M in O&M between 2009 and 2015 to implement its AMI plan. Deployment will begin in January 2009 or upon PUCO approval. There are four primary components of an AMI system configuration.

- ***Meters and Modules.*** The proposed AMI system calls for the replacement of all residential and commercial and industrial (C&I) meters with digital electronic meters and communication module combinations that provide full AMI functionality.

- ***Communications Network & Equipment.*** The AMI communications solution consists of communications hardware and software and associated system and data management software that create a two-way communications network between AMI meters and utility business systems which allow collection and distribution of information to customers and the utility.

- ***Home Energy Displays.*** DP&L's plan includes support for a customer Home Area Network (HAN) and includes energy display devices that are easily accessible and easy to use that show customers their current energy usage, trends, and current energy prices. DP&L will make energy displays available to customers who do not have Internet access or who choose to gain real-time energy usage information through this device rather than through the Internet.

- ***IT Systems.*** Effective implementation of advanced AMI technology requires installation of a MDMS and the modification and/or purchase of supporting IT systems which will make it possible for DP&L to manage the enhanced operational environment and take advantage of the new data that is captured by the AMI system.

1.3 Methodology for Preparing Business Case

Over the past year DP&L has been learning and evaluating the various technologies to implement AMI. Technology vendors have given presentations to cross-functional teams within the Company. DP&L employees attended several conferences and visited utilities that have implemented different components of AMI and smart grid technologies to gain a broader knowledge of the successes and pitfalls others have experienced in the implementations of these technologies.

DP&L also engaged a consulting firm, Bridge Strategy Group, to assist the Company in research and analysis to develop a feasible and cost-effective AMI strategy for its electric services. The principal aspects of the work were: (1) the identification of the goals for AMI and the potential costs and benefits of an effective and efficient advanced metering system, (2) the identification of appropriate technology, and (3) the analysis that reflects these findings.

The assessment of the cost-effectiveness of advanced electric infrastructure has been a complex undertaking. Cost estimates depend on the identification of the appropriate meters, the communication infrastructure, the meter data management systems, and load management system to be employed. Choosing among the available systems requires an understanding of how each possible system would be arrayed across the specific topography and meter locations in the Company's service territory in order to provide the desired degree of timeliness and consistency in the communication of meter data.

The information for estimating meter, communication equipment, and installation costs was developed from proposals provided by vendors based on a formal request for proposal (RFP) process. DP&L worked with a third party IT consulting firm to estimate the IT, IT-related infrastructure and IT integration requirements necessary to support the future AMI capabilities. The project team relied upon the IT firm's experience in utility specific transformation programs, as well as DP&L's knowledge of the existing infrastructure and future operating vision.

Integrated analysis was carried out by projecting the system costs on an overall basis for DP&L and forecasting other costs applicable specifically to each of the distinct areas within DP&L's service territory

Consistent with manufacturers' representations and the regulatory filings made by other utilities regarding expected equipment life, the cost analysis assumed a meter equipment life of 15 years, a communications infrastructure life of 10 years, and an information technology hardware life of 7 years.[1] The plan is for a six year system-wide deployment schedule commencing in January 2009 or upon Commission approval and with a 3.25% inflation rate applied to project costs.

[1] Southern California Edison Testimony Supporting Application for Approval of Advanced metering infrastructure Pre-Deployment Activities and Cost Recovery Mechanism. Volume 3-AMI Preliminary Cost Benefit Analysis (December 21, 2006)

2 DP&L Characteristics

2.1 Existing Metering, Communications, and IT Systems

2.1.1 Meters

Currently DP&L has a wide variety of meter types and technology. The metering technology runs from electro-mechanical to electronic, interval and to usage only. The company made the decision in 2006 to purchase only electronic meters in the future. There are 521,310 meters in the field, 501,826 are self-contained single-phase units and 19,484 are poly-phase and transformer-rated units. There are approximately 112,000 residential self-contained single-phase meters equipped with old one-way mobile reading technology. This figure represents approximately 22% of the residential meters installed in the DP&L service territory. There are 600 meters capable of interval data storage of the 19,484 poly-phase and transformer rated meters.

2.1.2 Communications Network and Equipment

DP&L currently owns and operates the following communication systems:

- An analog 800 MHz system used for voice dispatch of DP&L's mobile workforce.
- A 900 MHz multiple-address radio system for collecting substation SCADA data.
- A microwave back-haul system consists of thirty-two sites of which twenty-two are configured in an OC3 SONET ring. The remaining sites are hot-standby spurs ranging from 16 T1 to DS3 capacity.
- An OC12 SONET fiber system in the metro Dayton area connecting 16 substations in a collapsed-ring configuration. The Microwave and fiber systems are used to transport data for substation RTUs, substation protection, WANS, voice telephones, and the 800 MHz two-way radio system.

2.1.3 IT Systems

DP&L has several key legacy and home-grown IT systems in place to maintain daily operations. Our current customer information system, outage management system and service order processing system were designed and developed independently of each other and, over time, have been integrated with each other as needed. Although they are currently meeting our operational requirements, the advent of AMI will require a more flexible set of IT systems that will be able to meet the needs of our new AMI customer base and to enable customer participation in the evolving energy efficiency and demand response programs. It would be difficult and costly to further customize our existing legacy and home-grown systems in order to take advantage of the new opportunities and benefits afforded by AMI, respond quickly to market and regulatory changes, and create and manage a suite of energy efficiency programs tailor-made for our customers.

DP&L currently has a small Meter Data Management (MDMS) system. The Itron MV-90 system is used as the current data repository and data verification and editing tool for the interval meter data collected on 600 large industrial customers. The system is small, can grow only to approximately 2,000 interval data meters, and will not support the expansion into a fully-implemented AMI system.

2.2 Customer Characteristics

Key customer demographics such as customer type and geography drive feasibility, costs, and strategy for AMI.

2.2.1 Customer Type

Table 2.2.1. Number of Customers in Customer Classes

	Residential	Commercial	Industrial	Public Authority	Highway Lighting	Total
Customers	456,688	49,534	1,816	4,539	1,827	514,404
% of Total Number of Customers	88.8%	9.6%	0.4%	0.9%	0.4%	100.0%

2.2.2 Geography

The Dayton Power and Light service territory is 6000 square miles across southwest Ohio. Of this figure, 600 square miles are densely populated in the Greater Dayton, Ohio area, while 5,400 square miles are rural areas with small towns throughout the area. DP&L serves 24 counties across its territory. Approximately 60% of customers are in the Greater Dayton area, with the remaining 40% of customers in the rural areas.

3 Proposed AMI Systems Configuration

3.1 Meters and Modules

The proposed AMI system calls for the replacement of substantially all residential and commercial meters with digital electronic meters and communication module combinations that provide full AMI functionality defined as:

- Capable of measuring and recording usage data in time-differentiated registers, including 5 minute, 15 minute, hourly or such interval as is specified by DP&L.
- Allowing electric consumers, suppliers and service providers to participate in all types of price-based demand response programs noted in the project background.
- Providing the utility with key data and functionality that address power quality and other electric service issues. This information can be used to optimize the distribution network and to trouble shoot failed or failing equipment.
- Providing a Home Area Network gateway that can communicate with a variety of other key components necessary for the realization of energy efficiency and demand reduction during peak periods. These devices include programmable thermostats, home energy displays (HEDs), load control relays, and in the future smart appliances and switches and residential energy management systems.

- Supporting Bi-Directional and net metering where the meter can record energy flow in either direction and calculate net usage. This capability will be important in the future as distributed generation becomes a reality.

- All single-phase class 200 meters or less will have remote connect/disconnect capability along with load limiting capabilities

This functionality can reside in the meter alone, or will be provided through a combination of meter and network communications functionality.

The Company's proposed meter rollout schedule is provided in Table 3.1.

Table 3.1 Meter Deployment Schedule

AMI Meter Deployment	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Residential Meters	10,037	50,183	75,274	115,420	125,457	125,457	1,716	503,542
C&I Meters	389	1,897	2,846	4,364	4,744	4,744	-	18,984
Power Quality Meters	10	50	75	115	125	125	-	500
Total Meters	10,436	52,130	78,195	119,899	130,325	130,325	1,716	523,026

3.2 Communications Network and Equipment

3.2.1 Overview of Communication Requirements

The AMI communications solution consists of communications hardware and software and associated system and data management software that create a two-way communications network between AMI meters and utility business systems which allow collection and distribution of information to customers and the utility. The key attributes of the AMI Communications solution are:

- Provide coverage for 100% of meters in DP&L service territory.

- Capable of capturing 15 minute interval reads and reporting all of DP&L residential meters every 60 minutes.

- Capable of capturing 5 minute interval reads and reporting DP&L C&I customer meters every 30 minutes.

- Provides very low latency communications with the meter to do an on demand read/status inquiry of a customer meter while the customer might be on the phone with a DP&L customer care representative, within 10 seconds.

- Provides bandwidth to support the applications of tomorrow. These applications could include applications that create asynchronous message traffic to/from the HEDs and programmable thermostats. For example, emergency messages from the local municipality for weather, fire, or other threats or DP&L's retrieval of thermostat information regarding how often the air conditioner/furnace is in use. This information can be trended to detect when the customer may need a HVAC tune up or when filters should be changed. Applications could also include the need to send billing and usage information back to meter or energy display device when the user requests the information or on a regular or on-demand basis.

- Able to use the user interface of the C&I meter to access the meter remotely when there is a reported issue at a C&I customer, rather than having to put a power quality monitor at the customer's site.

- Able to support capturing the out-of-service and back-in-service transitions for large scale outages.

- The result will be a combination of multiple AMI communication technologies to reach all customers. Multiple technologies will be necessary to serve DP&L's diverse population density and terrain and to serve as an alternate way to reach meters when the primary approach of the AMI communication system does not work for a particular group of meters.

3.2.2 AMI Communications

AMI communications are divided into three key areas: AMI Infrastructure, 2-Way Voice/Data network, and Microwave IP backbone. These three networks make up the critical communications that provide the end-to-end communications to connect the AMI Meters for C&I and residential, new substation control, and the distribution automation devices on the

feeders to the DP&L IT systems that control, monitor, and collect data from these more than 500,000 monitoring devices in the field.

3.2.2.1 AMI Infrastructure

The AMI Infrastructure is the communications hardware and software and associated system and data management software that creates a two-way communications network between AMI meters and the new Microwave IP backbone that connects to the utility business systems which allow collection and distribution of the AMI information to customers and the utility. This infrastructure must provide the connectivity to all the meters in DP&L's service territory which has a very wide variety of coverage requirements, from urban to rural and from outdoor meters to those in a basement or metering closet. DP&L evaluated many AMI communication solutions and chose to use a single AMI solution across its diverse service territory to complement the 2-Way Voice/Data network that is providing AMI connectivity to DP&L's top 500 C&I customers.

The AMI infrastructure is located in DP&L substations and connected to the IP backbone through the new Microwave IP network (section 3.2.2.3) or through existing fiber assets. All of the IP backhaul associated with the AMI Infrastructure and 2-Way Voice & Data solution (section 3.2.2.2) will be owned and operated by DP&L to ensure the highest system reliability, security standards, and lowest overall cost of ownership as compared to purchasing broadband solutions from multiple IP service providers in the DP&L service territory.

3.2.2.2 Licensed 800 MHz IP Fixed Data Solution (2-Way Voice/Data Network)

This wide-area data network will be necessary to provide connectivity to over 500 of DP&L's largest Commercial and Industrial customers for AMI power quality services, to provide connectivity to distribution automation devices, and to ensure standard AMI service to 100% of DP&L's meters anywhere in its service territory.[2]

[2] Distribution Automation (DA) devices as described in *The Dayton Power and Light Company Smart Grid Development Plan.*

This new network was selected to enable the communications to DP&L's top 500 C&I customers while meeting DP&L's requirements for reliability, flexibility, throughput, and very low latency (less than one second response time). The licensed 800 MHz IP fixed data network supports IP communications at 96kbps over the air data rate, enabling DP&L not only to collect 5 minute interval AMI information but also to remotely open the user interface of the C&I meter to analyze key power quality measurements associated with the energy being delivered to DP&L's largest customers. This ability to view real-time power quality information from DP&L's largest customers in an on-demand fashion will enable DP&L to remotely troubleshoot and to monitor any power-related issues for this customer segment. Today's standard AMI solutions have high latency characteristics and cannot provide the real-time power quality feeds from the C&I power quality meters. And, while public carrier based IP solutions can provide real-time power feeds from C&I smart meters, these IP solutions do not have ubiquitous coverage throughout DP&L's service territory. In addition, public carrier-based solutions do not have the operational reliability required by DP&L during critical emergency situations.

The licensed 800 MHz IP fixed data network is also critical to support DP&L's smart grid strategy by providing communications to distribution automation devices that make up the new control and monitoring points in the electrical distribution network.[3] This network provides continuous coverage in the urban and rural areas as well as the reliability and security necessary to support these new critical components in DP&L's electric distribution network. The Company believes that for both safety reasons and for optimal control, the control of these active devices must be through a licensed, secure, and extremely low latency communication link that also has coverage throughout the service territory. It is important that the communication link be IP-based with significant capacity to be able to deliver remote, real-time SCADA information but also be able to remotely configure and troubleshoot control devices.

The third reason to deploy the licensed 800 MHz IP fixed data network is to deliver AMI capabilities to those otherwise excluded from the standard AMI solution due to lack of AI radio

[3] Detail of substation and distribution automation devices provided in *The Dayton Power and Light Company Smart Grid Development Plan.*

coverage for those meters. The number of meters that otherwise would be expected not to have AMI coverage is between 0.5% and 1.0%.

DP&L evaluated several potential solutions to meet the needs of power quality meters, distribution automation, and 100% AMI meter coverage. DP&L concluded that a licensed 800 MHz two-way IP fixed data solution would meet the Company's needs. Due to spectrum constraints in this band, the most cost effective method is to replace the existing analog 800 MHz dispatch solution with a multi-functional 2-way voice/data IP solution that can reuse the 800 MHz frequencies that DP&L already owns. Since the new system is spectrally more efficient it will meet the requirements of the licensed 800 MHz IP fixed data network as well as support the voice dispatch requirements that were previously supported by the existing analog 800 MHz system. Effectively, this new licensed 800 MHz IP fixed data solution will replace DP&L's existing analog 800 MHz system used for voice dispatch of the mobile workforce.

DP&L will see operational improvements associated with dispatch efficiencies from this new solution, as outlined in section 4.2 of this chapter.

3.2.2.3 Microwave IP Backbone

Due to the additional bandwidth needed to support the new data systems for AMI, distribution automation, substation automation, the licensed 800 MHz IP fixed data network, as well as the fact that the current SONET Microwave network is near 80% of its capacity, a new IP-based Microwave system will be installed. This network provides the connectivity to the licensed 800 MHz IP fixed data network base stations and AMI access points, and distribution substation communication gateways, located in substations dispersed throughout DP&L's 6,000 square mile service territory. The upgraded Microwave IP network will allow for IP traffic flexibility and bandwidth for all devices in the field along with bandwidth shaping capability and redundancy in case of any one individual link failure. This network will provide the necessary capacity, reliability, and security to support the extensive communications required for all of DP&L's needs related to AMI, energy efficiency, demand response, and smart grid.

The Company evaluated several options to provide the necessary bandwidth to support the integrated Customer Conservation and Energy Management ("CCEM") initiative. It was determined that the most cost-effective solution is to replace the existing SONET Microwave system. The existing SONET Microwave system does not have the additional capacity to support the communication from the substations, distribution automation components, or the AMI meters. DP&L explored an overlay design that would add an additional Microwave channel on the current ring architecture to carry the IP traffic. DP&L concluded that the most cost effective solution is to replace the existing SONET Microwave network with a new IP-based Microwave system. The primary benefits of this replacement strategy include:

- Reduction of maintenance from two microwave networks to a single network
- Reduction of power, battery back-up, and floor space requirements at the microwave sites
- More expedient switchover to back-up control center during a disaster

The capital and expense benefits of replacing the existing system that led DP&L to decide to replace the current system are outlined in section 4.2 of this chapter.

Also in support of the smart grid strategy, specifically the upgraded SCADA communications to the new communication gateways in the distribution substations, DP&L will deploy broadband IP radios to interconnect the Microwave sites with the remaining distribution substations not served by Microwave fiber. These broadband IP radios will not only support today's real-time SCADA monitoring traffic but also will support the remote configuration management and performance management reporting and troubleshooting capabilities of the new substation automation devices.

3.3 Home Energy Displays

DP&L's plan includes support for a customer Home Area Network (HAN) and includes home energy displays that will provide information on current energy consumption and prices.

The display will also receive and display signals regarding peak and/or critical peak pricing periods. Many customers will choose to get real-time information on energy usage, pricing, and trends from the new website portal that will be available to them via the Internet; however customers can request a home energy display (HED) by DP&L.

3.4 IT Systems

3.4.1 Summary Requirements

Effective implementation of advanced AMI technology requires installation of a Meter Data Management (MDMS) system and the modification and/or purchase of supporting IT systems which will make it possible for DP&L to manage the enhanced operational environment and take advantage of the new data that is captured by the AMI system. The technical integration of these systems will be implemented to ensure a smooth transition to the new operating model.

Exhibits 3.4.1.a and 3.4.1.b list the functional gaps that DP&L has identified in its current IT systems that need to be addressed.

Exhibit 3.4.1.a IT Systems Gap Analysis

Functional Area	Capability Gaps
Meter Data Management	**Currently DP&L's legacy MV90 and Field Collection Systems lack the ability to:** ▪ Capture and store hourly meter interval data required for incentive based rates or demand reduction initiatives ▪ *Capture and store meter related events for immediate action or compilation of data for studies over time* ▪ Calculate the billing determinants that will allow more flexible rate design and energy consumption billing ▪ Provide historical usage data to its residential class of customer that can enable demand reductions and energy conservation
Load Management	**Currently DP&L has no load management system in place and lacks the ability to:** ▪ Control load control devices for Demand Response benefits ▪ Aggregate multiple load control devices across device type or customer class to initiate effective demand response events ▪ Develop control strategies to meet the needs of particular demand response events ▪ Verify the activation of load control devices should a demand response event be called
Customer Information Management	**DP&L's legacy customer information system (CIS) will not readily support:** ▪ New customer rate and billing options (e.g. Critical Peak Pricing, Real-time Pricing) ▪ Online bill payment and customer self-service options ▪ Tracking of customer participation in proposed energy efficiency and demand response programs ▪ Easy integration with other systems critical to AMI ▪ Flexible reporting capabilities resulting in limited ability to report on key energy efficiency and demand response program success measures and targets ▪ Enhanced service order processing ▪ Flexible collection and payment options to maximize the benefits of AMI and energy efficiency and demand response programs ▪ Quick adaptation to new billing, accounting, and financial requirements necessary to manage non-commodity services ▪ Quick adoption of new cash processing methods and flexible payment posting options needed for non-commodity services ▪ Quick redesign of bill formats to show additional data related to AMI ▪ Quick design of customer correspondence and the ability to limit distribution to specific targeted customers ▪ Flexible processing of financial adjustments such as rebates or discounts available as part of new energy efficiency and demand response programs
eServices	**DP&L has a limited web presence and does not have the current capability to:** ▪ Support web-enabled enrollment in new energy efficiency and demand response programs ▪ Support web-enabled sign-up for Customer Energy Audits ▪ Accommodate online Customer Energy Use Surveys ▪ Allow customer to view their bill/bill insert(s) online to see current energy efficiency and demand response program credits and/or debits ▪ Allow customer to view past energy use ▪ Allow customer to view historical interval usage and the associated pricing ▪ *Support outbound web-enabled notification of energy events (e.g. direct load control, capacity load* reduction, scheduled load reduction, critical peak pricing, demand bidding, capacity bidding) ▪ Store and report on critical metrics to gauge program success.

Exhibit 3.4.1.b IT Systems Gap Analysis (Continued)

Functional Area	Capability Gaps
Outage Management	**DP&L's current outage management system lacks the following capabilities to maximize the benefits of the transition to AMI:** ▪ Capture and store meter events and alarms created by the AMI system ▪ Display the location of meter related events and alarms on a geographical electronic map ▪ Associate meter events with specific isolation and sectionalizing equipment within the DP&L distribution infrastructure ▪ Provide automated aggregation of both IVR and AMI related inputs to predict outage failure locations and isolation/sectionalizing equipment ▪ Provide automated restoration confirmation capability upon re-energizing sectionalizing equipment for restoration purposes
Mobile Workforce Management	**DP&L's current service order system lacks the following capabilities to maximize the benefits of the transition to AMI:** ▪ Generate and dispatch outage orders created by the Outage Management System ▪ Display the location service orders on a geographical electronic map ▪ Provide least cost travel routing for service orders ▪ Display real-time vehicle/staff location on a geographical electronic map ▪ Provide automated resource allocation based upon vehicle staffing and equipment availability in a *geographic area* ▪ Associate meter remove service orders with AMI systems and MDMS to prevent false outage signals ▪ Provide in-field order initialization and automated order completion within CIS ▪ Provide real-time service order status with communication to DP&L Call Center staff ▪ Provide service order assignment and scheduling based upon resource capability and geographic location
Distribution Management	**Currently DP&L has no distribution management system (DMS). A DMS would allow DP&L more efficiency to:** ▪ Perform System Analysis ▪ Plan Daily Operations ▪ Manage Planned Events ▪ Analyze Distribution System Optimization
Service-Oriented Architecture	**Current DP&L application integration organization, processes, tools and techniques are unable to:** ▪ Automate AMI and smart grid processes ▪ Capture real-time process data across systems and organizations ▪ *View end-to-end processes regardless of underlying supporting legacy systems, organizations or owners* ▪ *Quickly and efficiently modify end-to-end processes to meet the needs of customers and regulators*
IT Infrastructure	**Current DP&L servers and storage hardware are unable to support new applications.** **Current DP&L Disaster Recovery plans, processes, tools and techniques are unable to adequately support AMI and Smart Grid in the event of a business disruption or disaster at DP&L sites.** **Current DP&L IT infrastructure organization, processes and supporting systems software is unable to:** ▪ Support the increased Service Desk service levels required by users ▪ Schedule batch jobs efficiently and effectively ▪ Manage the many configurations of application versions in production, QA, test and development environments ▪ Monitor and manage the data network ▪ Efficiently plan and manage server and storage capacity ▪ Manage the increased security, identity and access requirements of AMI

3.4.2 Meter Data Management System

The primary purpose of a Meter Data Management System (MDMS) is to provide storage for and access to the massive amounts of data that will be obtained from an AMI system and coordinate/manipulate that data into actionable formats for the various other systems deployed as

a result of AMI. Types of data that will be captured for every AMI meter within the DP&L system include:

- Meter reading interval data
  - Hourly intervals
  - 15 Minute intervals
  - 5 Minute intervals
- Meter events
  - Tamper alarms
  - High/Low Voltage alarms
  - Minimum/Maximum Voltage readings
  - Flicker Counts (No voltage events less than x seconds)
  - Outage events (No voltage events exceeding x seconds)
  - Restoration events (Voltage return after and outage)

While MDMS is primarily a repository of data, it does provide functionality enhancing the capabilities of other systems through more accurate and granular data flow. Typical functionality includes validation, estimation and editing (VEE) of meter reading data and the calculation of billing determinants to be provided to the customer information system (CIS).

AMI coupled with MDMS provides the ability for CIS to generate time differentiated incentive based rates promoting the true cost of energy to its consumers. Additionally, this data, coupled with a more robust eService platform, can provide consumers with a view of their actual usage over time, fostering conservation, lowering the consumer's bills, and providing resulting system demand reductions.

Additionally, the MDMS provides data storage for reviewing consumption patterns for various classes of customers, improving analysis and accuracy for rate design, load forecasting for buy-versus-build decisions for both energy and capital improvements to the distribution infrastructure. MDMS will also act as a gateway to consolidate and communicate data flow from DP&L's various infrastructure systems (CIS, OMS, MWMS etc.) to the multiple AMI systems deployed within DP&L's service territory.

3.4.3 Load Management System

One of the important capabilities for DP&L's AMI deployment is to provide two-way communications to various in-home load control devices for voluntary demand reductions during critical peak periods on the DP&L distribution system. For DP&L to obtain this important benefit it must implement a Load Management System (LMS).

The primary purpose of a LMS is to provide a database of the load control devices that have been enabled through the DP&L CIS and have been installed throughout DP&L's customer base to allow for the aggregation and activation of those devices during a demand response event. In addition to maintaining the types, account numbers, locations, and distribution system information, the system will provide the following functionality:

- Load Control—The ability to control multiple load control devices into one demand response event.
- Demand Response Verification—The ability to verify that when a load control device is activated that it did in fact activate.
- Control Strategies—Maintenance of a table of various load control devices to provide predetermined demand response levels.
- Set Point Configuration—The ability to configure programmable thermostats for various temperature-set forward levels.
- Profile Support—Analysis routines that provide time-based profiles of the estimated achievable load response during a demand response event.
- What If Analysis—Provides the capability to assign and re-assign various load aggregation groups to estimate the most effective load control strategies under varying circumstances.

LMS coupled with AMI provides the ability for DP&L to control direct load control devices (DLC) and programmable thermostats based upon the scenarios and models that are created and stored in the LMS. Another critical function of LMS is to maintain a record of demand response events called for each device so that its use does not exceed the contractual obligations setup in either the rates or Demand Response Programs to which the consumer has consented.

A Load Management System coupled with effective demand response programs will allow DP&L to lower peak demand requirements during high usage or emergency curtailment periods across its distribution system. Additionally Load Management will improve the reliability of DP&L's distribution system for its consumers by allowing voluntary load shedding during system duress periods created by damage to its distribution infrastructure through accidental or storm-related equipment failures.

3.4.4 Customer Information System

DP&L's Customer Information System (CIS) is a set of process-related applications used to manage customer information for metering, billing, orders, collections, customer segmentation, rate activity, and payment processing. DP&L views the CIS as central to performing daily operations and key to customer satisfaction, making it a critical system.

In order to utilize fully the capabilities of AMI as well as its energy efficiency and demand response programs, DP&L will need to make enterprise-wide changes with regard to how we process vast amounts of data, manage new energy efficiency and demand response programs, implement new rates and modify the vast majority of our existing meter-to-cash business processes. Instead of having a CIS that enables our business to react quickly and effectively to the changing energy environment, the costs associated with modifying our legacy CIS have severely restricted progress with regard to embracing AMI, implementing evolving market rules, and accommodating the changing demands and expectations of our customers.

The combination of AMI and new energy efficiency and demand response programs will enable DP&L's CIS to perform enhanced billing calculations and support faster throughput capabilities as more data is processed to accommodate new billing, rates and flexible options from smart metering implementations. In addition, DP&L's CIS system must support benchmarking for customer care statistics, analysis of demographics, and customer segmentation to drive customer prospecting and retention practices, as well as to provide data to support business development process improvements. Therefore DP&L proposes the purchase and implementation of a new CIS whose more flexible and configurable architecture will allow for DP&L quickly and more affordably to make the changes necessary to deliver the value created by AMI, now and in the future. The new and improved features will become increasingly

important to our customers as DP&L strives to offer new demand side management options to its customers and to meet future energy efficiency and load control targets. This new system will be flexible, scalable and configurable, which will allow DP&L to focus on designing creative solutions to meet the needs of future unpredictable business conditions, while at the same time knowing it has the tools in place to make technical changes quickly.

3.4.5 eServices

As DP&L implements AMI and energy efficiency and demand response programs, we need to define a new approach to how it interacts with its customers and determine what the desired "customer experience" with DP&L will be. As our customers become more empowered to control their own energy use, DP&L must make the tools available to them to make this experience a positive one. DP&L realizes the need to integrate customer awareness and satisfaction into our energy efficiency and demand response strategy to maximize the value of our program investments. Details of proposed programs are provided in *The Dayton Power and Light Company Energy Efficiency and Demand Response Plan.* With this objective in mind, DP&L plans to develop a comprehensive set of eServices as a primary method to educate our customers about the programs we offer, the benefits of those programs and how to participate. Customers will be able to enroll in energy efficiency and demand response programs, participate in customer energy audits, and respond to customer energy use surveys via an enhanced company website. Customers will also be able to view their past energy use, billing information and historical interval usage and associated pricing data as part of the eServices DP&L plans to develop. Another critical component of DP&L's eServices offering is the capability for outbound web-enabled notification of energy events related to direct load control, scheduled load reduction and critical peak pricing programs, which will enable eligible customers to participate in these load reduction events.

Participating in an energy efficiency and/or demand response program may be the most significant interaction that many customers will have with DP&L. Even if they choose not to participate, knowing that DP&L offers these programs may have a significant influence on their behavior because they are more aware of their energy usage. By establishing a strong web

presence, and offering a variety of beneficial e-Service options, DP&L will be better able to increase customer satisfaction.

3.4.6 Outage Management System

For DP&L to maximize the benefits proposed by implementing AMI we will need to replace our legacy outage management system (OMS) with a more flexible and robust OMS. Currently our OMS accepts IVR information and actual customer contact information for the generation of outage events. A new OMS is needed to incorporate the additional data, such as outage alarms, restoration alarms, and low-and high-voltage alarms generated in real-time from an AMI System.

In addition to the compilation of massive amounts of data, OMS provides tools to restore power to DP&L customers efficiently. The new OMS will receive and process various inputs for outage analysis, predict locations of outages, manage crews, allow dynamic circuit model changes and maintain historical data. DP&L's current outage system was not designed or built for these types of advanced features. The following capabilities will allow DP&L to process information through all stages of an outage:

- Capture and store meter events and alarms created by the AMI system;
- Display the location of meter-related events and alarms on a geographical electronic map;
- Associate meter events with specific isolation and sectionalizing equipment within the DP&L distribution infrastructure ;
- Provide automated grouping of both IVR and AMI related inputs to predict outage failure locations and isolation/sectionalizing equipment;
- Provide automated restoration confirmation capability upon re-energizing sectionalizing equipment for restoration purposes;
- Provide outage-prioritization recommendations based upon loads, customer class, life support, or reliability indices;
- Provide automated reliability indices reporting based upon actual outage and restoration times and customers affected for business process improvements and regulatory review.

DP&L's mapping 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 SCADA. While these traditional methods of obtaining outage information are certainly valuable, they do not provide sufficient detail or the geographic visibility necessary to deploy work crews in the most efficient manner. The addition of real-time outage information originating from AMI, coupled with the customer's location provides the missing ingredient for efficient outage response, particularly during the occurrence of major outage events.

A sophisticated OMS is needed to manage the large amount of information generated from so many diverse sources. OMS will provide several operational layers that perform essential tasks related to outage detection, analysis, diagnosis and restoration. OMS is capable of identifying the various types of inputs, evaluating them by reconciling the divergent system, subsystem and endpoint sources, diagnosing the most likely causes(s) and current status, and then transferring this knowledge in a manner that efficiently utilizes DP&L's available restoration resources. OMS will provide for the efficient transfer of information concerning changing network status.

3.4.7 Mobile Workforce Management System

Implementing AMI will provide DP&L's customers significant benefits 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 Outage Management System and remaining field service order staffing, DP&L needs to implement a new Mobile Workforce Management system (MWMS).

While the existing Dispatch Administration Database system provides a level of efficiency for distributing and collecting field service orders generated by CIS, it does not allow real-time dispatching of priority service orders, service order completion, or generation/dispatch of outage related service orders.

A new MWMS will provide the following capability improvements:

- Generate and dispatch outage orders created by the Outage Management System;
- Display the location of service orders on a geographical electronic map;
- Provide least-cost travel routing for service orders;
- Display real-time vehicle/staff location on a geographical electronic map;

- Provide automated resource allocation based upon vehicle staffing and equipment availability in a geographic area;
- Associate meter-removal service orders with AMI systems and MDM to prevent false outage signals;
- Provide in-field order initialization and automated order completion within CIS;
- Provide real-time service order status with communication to DP&L Call Center staff;
- Provide service order assignment and scheduling based upon resource capability and geographic location.

MWMS takes advantage of the latest advances in mobile devices, handheld PCs, wireless communications and mobile software applications to maximize the utilization and productivity of DP&L's workforce. Automated scheduling and resource optimization, dynamic routing and workflow management, and global positioning and e-maps, combined with real-time communications between DP&L's operations center, call center, CIS, and field service order staff provide significant benefits to provide superior customer service and outage restoration.

Additional benefits from MWMS include:

- Resolving issues with fewer service visits and fewer onsite employees;
- Improving communications to reduce construction and maintenance delays;
- Enhancing employee collaboration;
- Providing service workers with the right equipment and improved skills so they can resolve problems onsite;
- Improving skills transfer from experienced workers to newer employees;
- Creating "paperless" processes to help reduce project delays and increase employee productivity; and
- Enhancing the security of personnel by addressing dangerous situations from the safety of the vehicle.

3.4.8 Distribution Management System

AMI is an enabling technology that provides a wealth of data on distribution system status, loading, and load forecasting. Coupling AMI information stored within the MDM with Geographic Information System (GIS), SCADA, OMS, and eventually substation and distribution automation[3] will be critical to unleash the power of AMI. The DMS project includes support for modeling of distribution substations in GIS and importing one-lines from GIS to be used for SCADA and DMS.

Implementing DMS at DP&L will allow the Company to more efficiently:

- Perform System Analysis, including:
  - Perform extensive scenario/contingency analysis of planned work scope.
  - Make certain that established standards and procedures are followed.
  - Ensure reliability of the system is not compromised by the work planned.
  - Maximize/coordinate the work that can be performed under the clearance
- Plan Daily Operations
  - Understand recent system events and the potential impact to planned scheduled work.
  - Anticipate major events that affect system integrity.
  - Review operational plans and ensure that compliance standards are met.
  - Develop efficient operational plans to reduce impacts on the real-time system environment.
- Manage Planned Events
  - Provide efficient method to generate switching orders.
  - Streamline Clearance management/approval process.
- Analyze Distribution System Optimization supporting a variety of Power System applications
  - 3-ph Power Flow
  - Volt-VAR Control
  - Short-circuit

- Equipment Condition Monitoring
- Load Survey Balancing
- Feeder Load Balancing and others.

The ability to analyze Distribution System Optimization utilizing near-real-time or actual distribution load data obtained enabled by AMI and stored in the MDMS can provide significant savings through reduction of system technical losses and 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.

The integration of OMS, DMS and SCADA at DP&L also provide the following operational benefits:

- One-network model for OMS and DMS analysis;
- Improved operations by close integration of DMS applications with SCADA;
- Increased operator efficiency with one system, eliminating the need to go to multiple systems with potentially different data;
- Integrated security analysis for substation and circuit operations to check for clearance tags in one area affecting operations in the other;
- Streamlined login and authority management within one system;
- Consolidated system support for DMS/OMS and SCADA;
- Simplified data engineering via coordination of SCADA point and GIS data changes.

3.4.9 Service Oriented Architecture

Service oriented architecture (SOA) enables easy automation, data capture and real-time measurement of high-value DP&L business processes such as end-to-end demand-side program management. High-value processes that DP&L automates with SOA will make them easier to control, more visible and more measurable. DP&L and third parties will be able to view processes and manipulate process data in real-time regardless of what multiple applications,

systems and organizations they span. Once DP&L's SOA capability is mature, process modifications are quicker and less costly because the work to modify the supporting IT is reduced.

SOA consists of:

- Communications which allow standardized point-to-point communication between systems through widely accepted open standards.
- An Enterprise Service Bus – allows a network of disparate systems to interact as one unified enterprise system by resolving differences in system hardware, software, networks and location.
- An Orchestration Engine / Business Process Management – allows automated integration of separate services to create integrated enterprise-level business processes.
- Business Activity Monitoring – provides end-to-end process performance monitoring and real-time insight and control of DP&L's business.
- A Service Registry (and/or Repository) – provides centralized Service Directory and Management Capabilities that support development-time and deployment-time activities (Publish/Discover) and run-time service look-up capabilities.

Examples of high-value processes from which both the customer and DP&L would benefit as a result of implementing SOA automation are end-to-end energy efficiency and demand response program management, real-time outage management and customer experience management.

3.4.10 IT Infrastructure

AMI infrastructure investment is comprised of three elements: 1. hardware to run applications; 2. disaster recovery and system software to achieve the required user experience; and 3. reengineered IT infrastructure governance and processes to meet required IT service levels.

1. Servers and storage are required to run AMI applications. This hardware must be sized to support required user performance (e.g., screen response time). Program success is risked if

undersized hardware makes the systems sluggish. Servers and storage are also required to support development, test and quality assurance environments.

2. DP&L's current disaster recovery capability does not meet the needs of AMI. New disaster recovery hardware and communications are required to adequately support AMI in the event of a business disruption or disaster at DP&L sites. New system software is required to enable the efficient management of applications (i.e., help desk, network monitoring, job scheduling, and configuration management). Use of these tools within the context of refined IT processes enables the reduction of the number of additional IT support staff in IT cost estimates.
3. AMI and smart grid are changing DP&L's business processes and governance model. IT infrastructure processes and governance will need to change too. Current processes, standards, procedures and staffing are engineered to support the current, less prominent use of IT at DP&L today. AMI and smart grid make IT more central to running the business. Business continuity planning must be geared to quicker, more predictable response in the event of a disaster. More users will have more questions on a greater number of systems central to doing their job, so service desk processes and tools should be reengineered. More robust security, identity and access management will be required to deal with the number of new applications, networks, and communication channels that pose unsecured entry risks. Virtualization, consolidation and capacity planning processes and tools ensure that servers and storage are used efficiently without wasted capacity. Virtualization was used in IT hardware estimates to reduce the number of required servers.

4 Cost/Benefit Analysis

4.1 Costs of Deployment

4.1.1 Meters

Meter capital costs include meter hardware, meter installation, incremental DP&L personnel for engineering and project management, and data collection resources to populate our existing Geographic Information System (GIS).

Table 4.1.1.a Meter Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Hardware	1,358,733	6,485,802	9,552,019	14,209,264	15,444,852	15,444,852	196,338	62,691,859
Meter Installation	171,864	876,506	1,341,055	2,097,410	2,325,389	2,371,897	31,891	9,216,011
Engineering & Project Management	2,028,805	1,786,144	1,819,453	1,431,361	1,211,276	1,113,291	447,114	9,837,445
GIS	2,250,000	3,000,000	1,750,000	1,750,000	-	-	-	8,750,000
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.1

The incremental O&M expense associated with the AMI meters comes from two expense categories: (1) Incremental personnel in the Network Operations Center to monitor the additional smart devices and AMI devices in the field. (2) Incremental personnel to analyze the AMI data coming from the network to be able to identify trouble areas and equipment before the customers do, as well as to manipulate the data to be able to understand better the electric load across the network and compare that information to the planned view. This data analysis enables DP&L to keep the AMI network running at peak performance and enables DP&L to realize some of the benefits that will are identified in the operational benefits section. There is no incremental O&M cost associated with the maintenance of the new AMI meters over and above what is already in the DP&L operational budgets for Meter O&M.

Table 4.1.1.b Meter O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	506,885	1,284,659	1,819,522	2,124,535	2,286,175	2,444,442	2,097,929	12,564,146
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.5

4.1.2 Communications Network Equipment

AMI communications capital includes hardware and installation and mobile device costs for 2-way voice data network, hardware and installation costs for AMI communications infrastructure, hardware and installation of the microwave IP backbone, and contracted engineers.

Table 4.1.2.a Communications Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
2 Way Voice & Data	10,538,042	3,848,829	235,714	180,300	-	-	-	14,802,885
AMI Backhaul	4,245,615	3,066,984	1,907,096	1,899,995	1,922,910	682,440	-	13,715,240
Microwave Backbone	10,442,850	7,272,870	-	-	-	-	-	17,715,720
Core Telecom Contracted Engineering	4,785,000	2,596,550	408,447	420,700	433,321	446,321	-	9,090,338
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1,129,761	-	[illegible]

source: WPH-1.3

Communications O&M costs are associated with two key areas: (1) Maintenance cost of the new communication systems being deployed, which is estimated at an annual expense of 5% of the cumulative capital for communications capital previously purchased. This figure covers the out-of-warranty repair costs for hardware, software maintenance fees, vendor call-in support, and the costs to re-install failed equipment. (2) Additional DP&L resources to maintain the new communications equipment in the field.

Table 4.1.2.b Communications O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	10,141,080
Total	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	10,141,080

source: WPH-1.6

4.1.3 Home Energy Displays

We expect to provide Home Energy Displays to customers who do not have Internet access, or approximately 30% of residential customers.

Table 4.1.3.a Home Energy Display Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Capital	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	13,438,486
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.2

The O&M for the Energy Display covers out-of-warranty repair, call-in support for DP&L customers and postage for shipping the Home Energy Display to/from the customer.

Table 4.1.3.b Home Energy Display O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
O&M	-	83,407	186,213	341,420	507,778	671,924	671,924	2,462,667
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.2

4.1.4 IT Systems

Table 4.1.4.a IT Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Data and Load Management System	3,531,625	3,210,751	2,744,330	-	-	-	-	9,486,706
Customer Information System	11,258,140	17,954,277	12,635,729	-	-	-	-	41,848,145
eServices (Website)	724,427	981,652	723,335	-	-	-	-	2,429,415
Outage Management System (OMS)	-	-	2,249,677	7,087,195	194,164	-	-	9,531,036
Distribution Management System (DMS)	-	-	2,920,942	4,087,556	1,481,716	486,322	318,942	9,295,478
Mobile Workforce Management (MWM)	-	-	-	-	6,966,291	2,396,581	460,855	9,823,728
SOA	1,840,756	381,937	699,884	936,511	884,178	535,826	-	5,279,091
Infrastructure	6,778,248	1,285,721	931	475	284	114	6	8,065,779
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.4, WPH 1-4.1 - 1-4.8

Table 4.1.4.b IT O&M Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meter Data and Load Management System	18,337	146,500	752,863	918,616	919,647	920,712	921,811	4,698,484
Customer Information System	206,987	140,638	1,524,500	1,349,809	1,673,852	1,675,790	1,677,790	8,249,365
eServices (Website)	3,416	32,336	197,567	355,566	355,985	356,377	356,803	1,658,031
Outage Management System (OMS)	-	-	56,021	671,328	516,339	696,326	697,158	2,637,171
Distribution Management System (DMS)	-	-	46,836	242,323	491,701	492,270	661,237	1,933,367
Mobile Workforce Management (MWM)	-	-	-	-	75,322	360,654	344,530	780,506
SOA	32,185	310,862	231,779	554,198	554,820	555,463	556,126	2,795,433
Infrastructure	32,842	760,995	1,980,661	3,110,390	3,113,882	3,117,486	3,121,208	15,237,454
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.4

4.1.5 Summary of Total AMI Deployment Costs

Table 4.1.5.a Total AMI Deployment Capital Expense 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	5,809,402	12,148,452	14,462,527	19,488,036	18,981,517	18,930,040	675,343	90,495,316
Communications	30,011,707	16,775,233	2,551,256	2,500,995	2,356,231	1,128,761	-	55,324,182
Home Energy Displays	-	1,668,142	2,056,121	3,104,146	3,327,147	3,282,929	-	13,438,486
IT	24,133,196	23,814,338	21,974,828	12,111,736	9,526,833	3,418,843	779,803	95,759,377
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1

Table 4.1.5.b Total AMI Deployment O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Meters	506,885	1,264,659	1,819,522	2,124,535	2,286,175	2,444,442	2,097,929	12,544,146
Communications	273,579	1,100,130	1,700,916	1,734,760	1,766,495	1,777,125	1,788,074	10,141,080
Home Energy Displays	-	83,407	186,213	341,420	507,778	671,924	671,924	2,462,667
IT	293,767	1,391,330	4,769,216	7,202,230	7,701,528	8,175,079	8,336,662	37,869,811
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1

4.2 Operational Benefits Portfolio

In the assessment of potential benefits that could be achieved through AMI, the Company examined, evaluated, and projected economic realizations in a number of categories.

Reduction in Meter Reading Expense - $11,149,321

AMI would eliminate on-cycle manual and mobile meter reading and associated costs. The benefit value includes all direct meter-reading labor expense, supervisory labor expense, vehicles, equipment, associated building leases, and other miscellaneous materials. Also included are maintenance/upgrade expenses for current meter-reading devices and yearly salary increases for meter readers and supervisors.

Reduction in Energy Theft - $8,833,691

We expect that AMI will reduce energy theft in three ways. First, during deployment, DP&L's vendor will be removing every existing meter and replacing it with a new solid-state meter and the installers will be trained to notice irregularities which can be investigated as potential theft. Second, a tamper-detection capability of new meters will virtually eliminate meter tampering as a source of energy theft, as the meter will provide tamper notification which will be analyzed and potentially investigated for theft. Third, the more sophisticated Meter Data Management System is expected to allow DP&L to better detect bypass and partial-bypass theft through data mining. The total of these three reductions in energy theft is anticipated to save an average of 0.5% of the revenue associated with each residential AMI meter.

Reduction in Uncollected Accounts - $970,120

The effect of the meter's remote disconnect capability on collections is a positive one based on the elimination of estimated readings and reduction in multi-month bills caused by failure to gain access to indoor meters. Most collection efforts center on a regimented process which is affected by missed reads.

Reduction in No Outage Calls - $502,509

This reduction is from a reduction of service calls to investigate customer meters that a customer believes is not performing properly. Since the AMI solution provides the DP&L customer operations team with the ability to look at the real-time meter status there will be a reduction in customer-generated service calls when the system is operating properly.

Reduction of Compensation/Claims for Meter Reading - $1,896,000

Utility costs for workers' compensation associated with injuries incurred by employees during meter reading can be reduced upon adoption of an AMI system, as meter readers

would no longer be exposed to high-crime areas, dogs, fences, adverse weather, etc. Costs associated with vehicular accidents occurring during travel between meter-reading locations in the field and utility premises would also be eliminated with AMI systems.

Increased Revenue Due to Improvement in Meter Accuracy - $7,069,353
Electro-mechanical electric meters begin to under record usage with age due to the wearing of the moving parts. Solid-state electric meters do not generally have this problem, and, therefore, average meter accuracy will improve as electro-mechanical meters are replaced. Moreover, solid-state meters fail more conspicuously than electro-mechanical meters and are, therefore, more readily identified. Sample testing of DP&L's electro-mechanical meters from the field have shown an average under usage recording of 0.4%.

Reduction of Bill Processing Costs due to Fewer Exceptions - $268,600
An important AMI benefit is a reduction in billing department resources needed to investigate billing problems and process adjustments. Daily readings from AMI eliminate the need for calculation of estimated bills caused by service contract disputes, back-dated cancellations and turn-ons. Keypunch errors and unusual usage patterns are eliminated or quickly detected by AMI, reducing the need for many of the more difficult billing problems that can occur, and which often take significant clerical time to resolve.

Reduction of Field Service - $3,476,000
Since the AMI system will be capable of obtaining daily readings from all customers, a reduction in the number of field services personnel can be achieved. A high percentage of field work in this category involves obtaining missed meter readings, and turning on and off customer services for cancelled and new accounts. In some cases, a physical shutoff is required, which takes even more time. AMI network services that produce daily readings can accomplish this function without the need for field visits, thereby bringing about a significant reduction in the number of personnel used for this purpose.

The implementation of the proposed AMI system will make the process of turn ons, and shut offs and off-cycle readings much easier on customers as well as resolve many meter access problems. The on-demand-read capability will enable the Company to read meters to issue

final bills or initiate service remotely. The increased process efficiency and reduced time to execute the request will make the company much easier to do business with and enhance the overall customer experience.

Again, the reduction in field personnel will produce a corresponding reduction in the need for indoor readings and in the number of vehicles used for these functions.

Deferral of Metering Capital Costs - $79,000

Deployment of AMI would defer the capital costs associated with replacement of meters and other manual meter-reading equipment (e.g., vehicles) that would otherwise have been required. This capital deferral is offset by the annual failure rate of newly installed AMI equipment (e.g., meters, telecommunications).

Reduction of Call Center Contacts for Bill-Related Calls - $650,960

Estimated meter readings often generate customer calls associated with billing issues. With monthly, daily, or more frequent readings from AMI, these missed readings and associated estimated bills can be reduced; thereby decreasing customer call volume, call duration time, and call center agent time spent handling these billing inquiries.

Reduction of Load Research Costs - $316,000

AMI can provide data that can be used for load research studies, thereby decreasing the need for more costly load research metering equipment and services, such as telephone lines and costly field maintenance.

Reduction of Revenue Losses from Unoccupied Premises - $110,600

With the ability to perform daily or more frequent readings, consumption from premises that are supposed to be unoccupied can be more quickly identified and addressed. DP&L will be deploying remote disconnect relays on all residential AMI meters, enabling the power to "inactive" meters to be shut off. This capability will limit utility exposure to write-offs of charges for consumption registered on "inactive" advancing meters on accounts closed after customers inform the utility they are moving out.

Reduction of Meter Testing Costs for New Meter Shipments - $63,200

During the deployment period of the AMI network there will not be a need to test a sample of the new meters shipped to DP&L. The cost of providing factory test information and system validation of all AMI meter deployments is included in the capital costs of the AMI solution.

Total Field Crew Savings from Telecom Upgrades - $884,986

This savings is from lower vehicle and overtime expenses through more efficient dispatch capabilities provided with the new 2-Way Voice & Data network.

Reduction in Existing Two-Way Radio and Microwave System Maintenance - $632,765

This savings comes from the reduction of maintenance expenses of the existing two-way voice and data system and the existing Microwave network after the deployment of the new Microwave and Two-Way Radio networks.

Reduction in Mainframe O&M - $6,588,670

This savings comes from capital improvements and maintenance cost reductions to the existing IT systems that are not going to be spent, given the deployment of the new AMI compatible IT systems that will be deployed during this time period.

Depreciation Savings from Early Retirement of Capital - $8,217,855

Due to AMI deployment we will retire select equipment earlier than expected reducing our total depreciation expense. In addition to meters, select IT will be retired early such as post-2008 software editions.

Table 4.2.1 Summary of Operational Benefits

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Reduction in Meter Reading Expense	32,670	228,690	638,040	1,296,295	2,166,250	3,119,376	3,668,000	11,149,321
Reduction in Energy Theft	27,950	195,647	545,018	1,076,061	1,746,852	2,445,593	2,799,569	8,836,691
Reduction in Uncollected Accounts	3,070	21,490	59,865	118,195	191,875	268,625	307,000	970,120
Reduction in No Outage Calls	1,388	10,004	28,705	58,375	97,607	140,749	165,682	502,509
Reduction of Compensation/Claims for Meter Reading	6,000	42,000	117,000	231,000	375,000	525,000	600,000	1,896,000
Increased Revenue Due to Improvement in Meter Accuracy	22,360	156,518	436,014	860,849	1,397,482	1,956,475	2,239,655	7,069,353
Reduction of Bill Processing Costs due to Fewer Exceptions	850	5,950	16,575	32,725	53,125	74,375	85,000	268,600
Reduction of Field Service	11,000	77,000	214,500	423,500	687,500	962,500	1,100,000	3,476,000
Deferral of Metering Capital Costs	250	1,750	4,875	9,625	15,625	21,875	25,000	79,000
Reduction of Call Center Contacts for Bill-Related Calls	2,060	14,420	40,170	79,310	128,750	180,250	206,000	650,960
Reduction of Load Research Costs	1,000	7,000	19,500	38,500	62,500	87,500	100,000	316,000
Reduction of Revenue Losses from Unoccupied Premises	350	2,450	6,825	13,475	21,875	30,625	35,000	110,600
Reduction of Meter Testing Costs for New Meter Shipments	200	1,400	3,900	7,700	12,500	17,500	20,000	63,200
Total Field Crew Savings from Telecom Upgrade	-	28,563	92,493	163,930	200,000	200,000	200,000	884,986
Reduction in Existing Two Way Radio System and Existing Microwave System Maintenance	-	20,423	66,132	117,210	143,000	143,000	143,000	632,765
Mainframe O&M Savings	-	-	-	1,556,765	1,614,265	1,675,827	1,741,813	6,588,670
Depreciation Savings from Early Retirement of Capital	8,336	241,377	528,604	1,596,931	1,875,216	1,873,509	1,993,881	8,217,855
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

source: WPH-1.4, WPH-1.7, WPH-1.8

5 Implementation Planning

5.1 Deployment Schedule

The Company expects to begin deployment in January of 2009 or upon approval from the Commission. Approximately one hundred percent of meters will be replaced over six years. Core enabling telecommunications will be fully installed by end of year four. While IT systems necessary to support core meter functionality are expected to be in place by the end of year three.

Table 5.1 Deployment Schedule

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7
System Automation Infrastructure							
Meter Installation							
Communication Network Infrastructure							
Home Energy Display							
Geographic Information System Data Collection							
Information Technology Infrastructure							
Customer Information System / eServices							
Meter Data Management							
Infrastructure Solution							
SOA – Service Oriented Architecture							
Outage Management System / Distribution Management System							
Mobile Workforce							

Appendix A: Technology Assessment

Traditionally, utilities have used single-purpose systems to satisfy specific business needs such as outage management, distribution automation, meter reading, two-way voice dispatch, and general purpose data acquisition. These solutions generally involve a hardware device controlled by a stored program, a communications network (telephone, cellular, powerline communications, Ethernet, or other network service), and an appropriate information reception, execution, processing, and distribution system (data warehouse, back office, head-end, or master station).

Utilities have a fundamental business requirement to read meters so they can render accurate bills to their customers. AMI systems provide the utility with the ability to gather data remotely on consumption and on indications of meter tampering; they can also relay other core meter functions. The chart below lists the additional functionalities that are enabled by migrating from Handheld & Mobile Meter Reading systems to a fixed two-way network that is fully enabled by AMI.

Functionality Available
• Integrated remote service reconnect & disconnect
• Advanced (time-based) rates
• Distributed Generation detection and control
• Remote meter programming
• Net Metering
• Power Quality monitoring/reporting
• Home area network interface
• Enhanced security compliance
• Daily or on-demand reads
• Interval data
• Outage notification
• Load profiling
• Automated monthly reads
• Tamper reporting
• Improved meter read accuracy

The migration from Handheld & Mobile Meter Reading systems to AMI is characterized by a more robust communications means that enable more frequent two-way interaction, both scheduled and by exception, and other functionality between the meter, the MDMS, OMS, DMS, and more traditional backend systems.

Electric meter technology has been evolving and continues to evolve. Along with the transition from electro-mechanical to solid-state devices, meter communication elements have become more available and are becoming less expensive. With the integration of communications, AMI technologies can have functionality beyond the utility's monthly revenue meter-reading requirements. AMI systems open the possibility of integrating a load-limiting functionality, along with the ability to interact with the gas and water meters and other devices in the customer's premises. The industry is moving to communications featuring open architecture and device interoperability. This is critical to achieving these benefits.

While virtual AMI provided by a fixed network is expected to be able to support time-of-use rate forms, the intelligence, processing power, storage, communications, and timekeeping that can be incorporated in AMI-enabled meters can readily support a variety of other time-based tariff programs, such as real-time and critical peak pricing. Further, the AMI facilitates customer price response and participation in energy efficiency and demand response programs. Properly equipped, many AMI devices can interface directly with premises-based devices such as programmable communicating thermostats and other display and interactive devices. Therefore, it is possible for consumers to set simple rules-based actions for their loads and better manage their energy costs through automated control technology. This functionality is a significant enhancement over simple direct load-control functions for both customers and the utility.

AMI also provides better utility oversight of customer performance by enabling the monitoring of the individual load prior to the load control event and measuring the load reduction following a control command. This measurement and verification function adds a greater level of confidence compared to one-way direct load control solutions, where the efficacy

of such control efforts can only be measured indirectly after the command is executed and the reduction occurs.

In addition, AMI functionality can enable many utility-centric and operations-related services, including:

- Monitoring some types of distribution system conditions and events, such as power quality disturbances,
- Improving the reporting of electric outage conditions and interruptions,
- Providing additional reliability by remotely disconnecting or limiting and, with safeguards, reconnecting electric service through the addition of an integrated service switch,
- Capturing and reporting time-stamped load monitoring data for system analysis and planning, and
- Providing the ability to remotely upgrade meters or device components without the need to make costly field visits for meter replacements or upgrades. Such upgrades may be due to industry changes to security algorithms, adjustments to daylight savings time (for time-based rate offerings), and the Companies' desire to make changes to operating characteristics and algorithms inherent in these devices.

Communications Technologies

The Company considered several different communications technologies, which are described below.

Telephone and Digital Cellular

A public communications system, such as a standard telephone line or a wireless cellular network, can be used to link individual meters directly to utility back-end systems. While the Company currently uses landline dial-up telephone service for meters on certain types of electric service, the general use of this communications method for a mass-market infrastructure would be costly and problematic due to the customer's tendency to remove the telephone line from the meter on occasion.

Moreover, although the monthly costs of telephone lines have decreased over the years, a trend in the residential market is for the traditional "land-line" to be replaced with a cellular phone, or VoIP phone, thus eliminating the affiliation of a phone number to a fixed location. The costs of a cellular connection have decreased as well. However, the recurring fees for use of this method as a data collection alternative for mass-market meter reading are substantially greater than other network arrangements considered. Nevertheless, both telephone and cellular techniques remain options for special cases where another type of AMI communications is impractical or impossible.

Mobile and Fixed Network Radio Frequency (RF)

In Dayton, DP&L currently uses AMR in a drive-by mode, sometimes referred to as Mobile AMR. This method requires a vehicle equipped with instrumentation capable of gathering meter data to be driven past meters that are equipped with a low-powered RF module operating on an unlicensed frequency. The meters (either gas or electric) can either be awoken to broadcast information (this is the typical arrangement with battery-powered units in gas and water meters) or they can continuously broadcast or "bubble up" their information (this is the more typical method for electric meters where the power consumption of the RF module is not an issue). Because of the need to pass near each meter to obtain its reading, Mobile AMR is typically used for reading meters once each billing cycle.

A "fixed network" is established in an area with RF-based AMR meters with the installation of collectors located on utility pole tops, utility towers, or similar structures. The network can then effectively operate as a remote collection system, that is, one that is capable of gathering information from meters on a more frequent basis and of communicating this data to the master station and responding to requests for meter data that are locally stored at the collector.

RF Mesh

In this technology, the meters have the ability to relay data both from their own registers and from other meters. This arrangement creates a network among end-points through meter-to-

meter communications. This interconnected network is used to extend the range of the AMI modules, optimize the communication paths, and reduce the number of pole-top data collectors required (as compared to the fixed AMR network described above). Communications reliability is generally improved because the messages are not assigned a specific path but can be routed through the "best" path in the network at the time of transmission. By designating key points in this mesh network as "take-out points," this configuration can reduce the total number of collectors and master-station relay points (concentrators) that would otherwise be required in a more typical fixed network. These take-out points are typically mounted on utility poles or similar structures and sometimes in designated meters that have wireless backhaul built into them.

RF Point to Multi-Point

AMI systems in a Point to Multi-point architecture use higher-powered RF modules operating in a licensed frequency to communicate with data collectors. Systems with this configuration can enable a full two-way network. Additional functionality, such as soliciting an ad hoc individual meter-reading interrogation, querying the meter to provide information on power quality, and communicating directly with individual peripherals, is based on such a system's capability to send information to or receive information from specific points. This higher-powered configuration can communicate directly with many more meters and requires fewer but commensurately more costly radio transceivers than a fixed network or a RF mesh network and are typically installed on communications towers. The Point to Multi-Point system do have an advantage of less backhaul points and ongoing operational costs to get the data to the back end utility IT systems.

Broadband over Powerline (BPL)

Solutions are available that can enable a high-capacity data network to be created in the existing electrical infrastructure. These "broadband over powerline" networks provide high-speed connectivity. Many utilities indicate a growing interest in and early use of these techniques for utility-oriented services such as electrical distribution asset monitoring, substation video

surveillance services, and AMI. However, this communications technique has a high level of uncertainty both in technical and total functionality in the network distribution grid. Since BPL is still evolving and the Companies' evaluation of this technique is in the early stages of feasibility studies, this method was eliminated from consideration in the Company's current business case. Although BPL may be viable in radial distribution networks, the present costs of this communications infrastructure and the greater cost of BPL-enabled meters make this technology significantly more costly than the other AMI methods considered.

Powerline Carrier (PLC)

PLC likewise uses the existing electrical distribution network as a means to communicate to and from meters. However, this technology operates at a lower frequency range, providing a very low-speed and high-latency communications network. This system uses vendor-supplied coupling equipment and sensors at key points within the distribution network. These devices communicate with meters that contain the powerline signal decoding and modulating unit. When a specific meter that corresponds to a designated address (or group of meter addresses) is interrogated, it interprets the respective command and sends a message (or messages) in response to this poll.

For other devices that are not connected to the power line, such as gas or water meters, a low-power radio transceiver included in an adjacent or nearby electric meter may allow the electric meter to act as a gateway or relay for these other devices. This secondary RF-link enables the utility to communicate, albeit indirectly, with gas meters, water meters or customer-premises devices, such as thermostats or other peripherals.

At the substation, there is a communications link that provides a data path to the back office. This link can use any common data network means that is appropriate, including, but not limited to, telephone landline, wireless telephone, WiFi, Microwave or other WAN connection.

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

Chapter 4

The Dayton Power & Light Company's Smart Grid Development Plan

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1 Introduction

1.1 Smart Grid Overview

Dayton Power and Light ("DP&L") defines "smart grid" as an inter-connected system enabling more efficient and reliable delivery of energy through real-time and secure automated controls.

A smart grid includes a fully network-connected system that identifies and communicates grid status and automates transmission and distribution decision-making systems. This vision uses vertical system solutions currently available and deploys a horizontal integration of these systems into a real-time, secure, and automated network that will manage all of the variables involved in delivering energy to the consumer. This advanced decision-making system will allow DP&L to deliver energy more efficiently and reliably.

1.2 Focus on Performance and Outcomes Improvement

Expected results from planned smart grid implementation will be a greatly improved delivery system that reduces line losses, maximizes customer service and system reliability, allows for operational savings for DP&L and generates substantial benefits for society at large.

Smart grid infrastructure is expected to create an energy system that will enhance both operational performance and improve outcomes by allowing DP&L to:

- Detect and address emerging problems on the system before they affect service;
- Respond to local and system-wide inputs and provide additional information about broader system problems;
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances;
- Automatically adapt protective systems to accommodate changing system conditions,
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem;
- Enable distributed energy resources and demand response loads to be integrated into operations;

- Improve reliability and security; and
- Provide system operators with advanced visualization tools to enhance their ability to oversee, manage, and troubleshoot the system.

By this Application DP&L proposes a seven-year development plan, described in section 1.3, through which the Company will test and validate various technologies that are critical to improving operations on DP&L's grid. Based on the results of the development phase the Company will either advocate full deployment or a shift in focus to new technologies.

1.3 Executive Summary of Smart Grid Plan

1.3.1 Summary Smart Grid Plan

The Company's long-term vision of a smart grid includes a fully network-connected system that identifies and communicates the status of the power grid and automates transmission and distribution decision-making systems. By means of this Application, however, the Company is proposing to test a limited set of technologies commonly considered part of a smart grid. DP&L plans to test individual technologies and smart grid concepts, primarily pertaining to distribution and substation automation, in combination with AMI systems and demand response programs to validate assumptions regarding operational, reliability, and efficiency benefits.[1] Following this 7-year development phase DP&L expects to submit an expanded proposal for full deployment of an integrated smart grid deployment plan.

The development phase focuses on effective implementation of distribution automation technology which requires installation of a series of controls, switches and monitors as well as a supporting communication infrastructure.

In addition, the Company proposes to automate substations by upgrading relay protection and communication systems in substations to enable fault isolation and load redistribution in

[1] See detail of DP&L's proposed energy efficiency & demand response programs and AMI plan in *Dayton Power &Light Company's Energy Efficiency & Demand Response Plan* and *Dayton Power & Light Company's Advanced Metering Infrastructure Plan*

conjunction with the distribution automation technology being deployed. In order to realize the reliability improvements enabled by real-time distribution of substation loads under fault conditions, the Company proposes the simultaneous deployment of substation automation and distribution automation in the development phase.

1.4 Methodology for Preparing Business Case

With assistance from the Bridge Strategy Group, DP&L evaluated potential smart grid initiatives using the following five steps: (1) assessed the current state of the energy infrastructure and climate in the region (as-is state), (2) compared the current state to a future smart grid scenario to identify technological, regulatory, and consumer system issues, (3) identified a core group of smart grid technologies that when implemented together would provide the framework for the smart grid, (4) conducted a cost-benefit analysis to determine if there is a business case for implementing the technologies identified, and (5) recommended an implementation strategy for the identified technologies.

Integrated analysis was carried out by projecting the system costs on an overall basis for DP&L and forecasting other costs as applicable specifically to each of the distinct areas within DP&L's service territory.

Consistent with both manufacturers' representations and the regulatory filings made by other utilities regarding expected equipment life, the cost analysis assumed equipment life of 30 years. The analysis also assumes a seven-year system-wide deployment schedule commencing in January 2009 or upon Commission approval.

2 DP&L Characteristics

2.1 Existing T&D Infrastructure

DP&L's distribution system is comprised of approximately 11,500 miles of distribution lines, served from 145 substations. Feeding the distribution system are 1,780 miles of transmission lines with 968 miles operating at 69kv, 380 miles of 138kv and 433 miles of 345kv. There are 176 switches on the 69kv system and 31 on the 138kv system. These switches are manually operated. They are neither monitored nor controlled by the system operator, and do

not communicate with other devices. The existing SCADA ("Supervisory Control and Data Acquisition") system is connected to 106 substations. The remaining 39 substations are monitored via dial-up connections ("EI"). The EI system attempts to call when an event or alarm occurs at the monitored station. The existing EI system is not as reliable as new systems and the reporting of alarms and events may take hours or days to be sent to the system operator. SCADA is utilized to monitor substation events including loading and alarms and to operate breakers or load tap changers inside the substation. SCADA systems are characterized as controlling events "inside the fence" at substations.

The distribution system is composed of a variety of operating devices: air Break Switches, single and three-phase reclosers, fixed and switched capacitor banks, and voltage regulators to name a few. Switches and reclosers are used to sectionalize circuits and to pick up load. Capacitor banks and regulators are set to maintain voltage and maximize the power factor along the feeder, minimizing line losses. These devices are not monitored or controlled by the system operators who currently only have visibility into substations via the existing SCADA system and who otherwise rely on outage management reports based on call-ins and circuit diagrams in order to direct DP&L field crews. Reclosers are programmed to react automatically to fault conditions and to minimize the number of affected customers. There are a variety of switched capacitor bank controls. Simple schemes operate at 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.

3 Proposed Smart Grid Development Plan

3.1 Distribution Automation

Effective implementation of distribution automation technology requires installation of a series of controls, switches and monitors as well as supporting communication infrastructure. DP&L plans to automate 4 circuits per year in years 2009 through 2014 and starting in 2015 will begin more aggressive rollout with the automation of between 30 and 50 circuits. Subsequent to

this seven-year development phase, we expect to continue at the rate of 30 to 50 per year through 2023.

The process of automating a circuit will entail the installation of one or more of the following devices and equipment:

Automatic Reclosers

Install three-phase reclosers with full communications and control to minimize the number of customers affected by circuit operations. These devices operate automatically to isolate faulted line sections.

Capacitor Banks

Analyze each distribution circuit for reactive power, and then develop a master plan for both fixed and switched capacitor banks. Existing banks may be utilized, re-deployed, or re-built with new controls and communications.

Air Break Switch Controls

An aggressive replacement program is in the final stage of completion. The unitized switch reduces the need for maintenance and adjustment of the operating mechanism. These switches are used to isolate circuit sections and to pick up load from other sources. Communications and motor operators are needed to integrate these into the DA program.

Single Phase Sensors

These devices are used to monitor loads at various points on the distribution system, which can lead to a reduction in outage times, particularly during cold load pickup.

Voltage Regulator Controls

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.

Pad Mounted Switch Gear

These devices are three-phase gang-operated switches for switching operations on the underground distribution system which operate similar to air break switches. The addition of relaying and motor operators will allow for fault isolation and service restoration in a timely manner.

New Poles

To facilitate the installation of the new devices (capacitor banks, reclosers, and voltage regulators), pole replacement and new pole installation will be required.

In addition to the DA devices and equipment, the following measures will be necessary to realize the potential of an automated circuit:

Distribution SCADA Support

The installation of multiple devices in the field will require a distribution SCADA tool. The number of data points will increase dramatically over the existing SCADA system. DP&L currently monitors fewer than 10,000 data points on the transmission system including distribution breaker information. For a complete distribution automation system DP&L will monitor 30,000 data points.

Implementation of 2-Way Voice/Data Communication to DA Devices

At the heart of the Distribution SCADA system is a robust communication system to allow for real-time data collection and control from the various sensors and devices on the system. This communication network also will position us for automated data dispatch.

DP&L Engineering & Project Management

Significant engineering time will be required to coordinate the devices proposed for the system. Relay and feeder switching schemes must be properly designed and tested prior to implementation to ensure proper operation of each component. The installation of components will require coordination with various work groups to ensure all components

are installed in the appropriate timeframe and to DP&L standards. New Standard Operating Procedures must be developed to ensure that safety standards continue to be met while accommodating the automatic and operator control of the equipment in the distribution system.

Outsourced Engineering

External engineering resources are needed to assist in creating the new processes, programs, installing additional equipment and supporting the expansion of equipment deployment after year 6 when the volume of circuits increases dramatically. Power factor analysis, capacitor installation, and fuse/device coordination are all functions that will require circuit analysis, design, and optimization during and after the initial deployment.

3.2 Substation Automation

Effective implementation of substation automation technology requires upgraded relay protection and communication systems in substations to enable fault isolation and load redistribution. In years 2009 through 2014 DP&L plans to automate 6-7 substations per year and in the final year of the pilot, 2015, will automate an estimated 12 substations. Subsequent to the pilot we expect to continue to automate substations the rate of 12 per year through 2023.

Specific technology and infrastructure required to fully automate a substation will include the following:

New Relays

To fully implement smart grid technology, electro-mechanical relays need to be replaced with digital, programmable relay schemes. The digital relays store event data that can be accessed to aid in the diagnosis of circuit problems. The digital relays do not require on-going calibration; via secure communications, they can be remotely adjusted for changing field conditions.

Upgraded Pilot Wire

The Pilot Wire Upgrade to a fiber network is necessary to allow protection switching between the various relays around the Crown Substation area. The current copper wire system is inadequate for DP&L's system needs and causes additional transmission lines to trip due to a lack of communication between the substations. The fiber will also be used for SCADA communication to the substation equipment in this region and will provide backhaul for AMI infrastructure co-located in these substations.

Communication Gateways

Communications between the Distribution SCADA control system and the Distribution Management System is critical to the success of the CCEM program. The real-time collection of data from the various sensors at the substation and the control of the smart grid enabled substation equipment will be used for contingency switching plans, optimizing the voltage of the substation during normal conditions, which when done in conjunction with capacitor banks and monitoring the voltage at the smart meters can lower the line loss along the distribution network. In addition, the communication gateway at the substation will be used to adjust the voltage at the Substation during normal operations and during peak energy conditions to reduce peak energy demand.

SCADA Communication Upgrade

DP&L will provide real-time communications to all substations through IP-enablement of existing Fiber, upgrading the Microwave sites to support IP, or through broadband IP radios. The communication gateway requires a distribution tool and real-time communication system to bring substation data and control back to the system operator. The distribution SCADA system and communication upgrade will permit the operator to monitor the state of the substations and distribution system and respond to changing field conditions to minimize customer outages and power system losses.

2-Way Voice Radios

Communications between system operators and field maintenance crews will be required for advanced switching and maintenance activities. Release of specific equipment and

clearance points associated with each device is required. In addition, the 2-Way Voice and data network will supply an IP communication pipe between the Distribution SCADA system and the communication gateway in the substations.

Similar to the resources required for distribution automation, DP&L engineering, project management, and outsourced engineering resources will be required to move from non-monitored substations to a fully-automated system. Communication paths between substation RTU's and system operating must be designed for the approximately 40 substations not currently monitored via the SCADA system. In addition, relays at these substations will need to be upgraded to digital recording relays.

4 Cost/Benefit Analysis

4.1 Costs of Deployment

4.1.1 Distribution Automation

Table 4.1.1.a Distribution Automation Capital Expense 2009-2015 ($)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Reclosers	294,800	288,904	283,126	267,817	282,060	276,419	3,250,687	4,963,813
Capacitor Banks	149,600	146,608	143,676	140,802	137,986	135,227	1,590,264	2,444,163
Air Break Switch Controls	96,800	94,864	92,967	86,552	84,821	83,125	977,545	1,616,673
Single Phase Sensors	52,800	51,744	50,709	49,695	48,701	47,727	561,270	862,646
Voltage Regulator Controls	24,200	23,716	23,242	21,638	21,205	20,781	244,386	379,168
2-way Voice/Data Modems for DA Devices	37,950	37,950	37,950	37,290	37,290	37,290	447,480	673,200
Pad Mounted Switchgear	12,100	11,858	11,621	11,388	11,161	10,937	128,624	197,690
New Poles	11,000	11,000	11,000	11,000	11,000	11,000	121,000	187,000
DP&L Engineering & Project Management	641,888	661,145	789,321	813,001	837,391	862,513	1,167,076	5,772,335
Outsourced Engineering	322,123	490,187	396,550	385,000	346,500	311,850	280,665	2,532,875
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 4.1.1.b Distribution Automation O&M 2009-2015 ($)

Maintenance Cost (3% of Installed Capital)	-	20,048	39,717	59,016	78,071	96,768	115,113	408,731
DP&L Personnel	108,579	111,837	115,192	118,647	122,207	125,873	129,649	831,984

Distribution automation O&M costs are associated with two key areas: (1) Maintenance cost of the new distribution and communication systems being deployed, which is estimated at an annual expense of 3% of the cumulative capital for distribution automation capital previously purchased, and includes the out-of-warranty repair costs for hardware, software maintenance fees, vendor call-in support, and the cost to repair failed equipment. (2) Additional DP&L resources will required to maintain the new equipment in the field.

4.1.2 Substation Automation

Table 4.1.2.a Substation Automation Capital 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
New Relays	912,621	912,621	912,621	324,833	286,958	542,539	1,206,127	5,098,319
Upgrade Pilot Wire	2,640,000	660,000	-	-	-	-	-	3,300,000
Communication Gateways	730,400	369,600	220,000	99,000	-	-	-	1,419,000
SCADA Communication Upgrade	906,400	2,482,508	1,094,702	455,400	-	-	-	4,919,010
DP&L Engineering & Project Management	210,702	434,047	447,068	460,480	474,294	488,523	632,828	3,147,942
Outsourced Engineering	495,000	571,032	588,163	606,808	623,982	642,702	661,983	4,188,669
Total	[illegible]	[illegible]	3,262,554	1,946,521	1,385,234	1,573,764	2,500,938	22,072,941

Table 4.1.2.b Substation Automation O&M 2009-2015 ($)

Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Maintenance Cost (3% of Installed Capital)	-	213,840	319,660	381,260	408,980	408,980	408,980	2,141,700
Outsourced O&M HC Costs	-	150,000	154,500	159,135	163,909	168,826	173,891	970,261
Total	-	[illegible]	474,160	540,395	572,889	577,806	582,871	3,111,961

Substation automation O&M costs are associated with two key areas: (1) Maintenance cost of the new relays and communication systems being deployed, which is estimated at an annual expense of 3% of the cumulative capital for substation automation capital previously purchased, and includes out-of-warranty repair costs for hardware, software maintenance fees,

vendor call-in support, and the cost to repair failed equipment. (2) Additional DP&L resources will be required to maintain the new equipment in the field.

4.1.3 Summary of Seven Year Smart Grid Development Costs

Table 4.1.5.a Total Smart Grid Development Capital Expense 2009-2015 ($)

Distribution Automation	1,643,261	1,817,976	1,840,162	1,844,183	1,818,116	1,796,869	8,768,997	**19,529,563**
Substation Automation	5,895,123	5,409,807	3,262,554	1,945,521	1,385,234	1,673,764	2,500,938	**22,072,941**

Table 4.1.5.b Total Smart Grid Development O&M 2009-2015 ($)

Distribution Automation	108,579	131,884	154,908	177,663	200,278	222,641	244,762	**1,240,715**
Substation Automation	-	363,840	474,160	540,395	572,889	577,806	582,871	**3,111,961**

4.2 Benefits Portfolio

In the assessment of potential benefits that could be achieved through smart grid technology, the Company examined, evaluated, and calculated economic realizations in a number of categories.

4.2.1 Operational Benefits

Reduction of Planned Substation Capital Costs - $523,276

The substation upgrades eliminate planned upgrades for the substation equipment.

Reduction of Capacitor Bank Manual Inspection - $135,782

Distribution automation-enabled automatic monitoring of capacitor banks reduces the need to perform manual inspection of capacitor banks.

Better Utilization of Substation Capital - $104,655

Monitoring of the substation equipment helps ensure that equipment is not operating outside recommended parameters, increasing the life of the equipment.

Reduced RTU Maintenance Cost - $113,634

The upgrade of the communication gateways eliminates the cost of maintaining some of older RTU's currently deployed in DP&L substations.

Savings from Increased Crew Productivity - $88,913

Distribution automation-enabled fault isolation enables crews to spend less time identifying the point of failure. The deployment of the 2-Way voice/data system that provides the communications to the new distribution and substation automation equipment also supports more automated dispatch of the DP&L field teams.

Reduction in Transformer Replacement Capital - $75,849

The improved monitoring of voltage, current, and energy in the distribution network helps to eliminate overloaded distribution transformers and to extend their operational lives.

Deferral of Capital Costs (Switches, Cap Banks, etc.) – $53,127

The distribution automation upgrades eliminate planned upgrades for the distribution equipment.

Increase in DP&L Revenue due to SA Related Reduced Outage Time - $16,905

Shorter and less frequent outages due to substation equipment failure will enable the Company to deliver additional electricity to customers, resulting in improved customer service.

Savings from Reduction in Outage Related Calls - $7,873

Shorter and less frequent outages will reduce customer service call volume, resulting in better customer service and call center cost savings.

Increase in DPL Revenue due to DA Related Reduced Outage Time - $7,852

Shorter and less frequent outages due to distribution equipment failures will improve customer service and enable the Company to deliver additional electricity to customers.

Table 4.2.1 Summary of Operational Benefits

Reduction of Planned Substation Capital Costs	11,207	31,034	51,724	72,414	93,103	115,517	148,276	523,276
Reduction of Capacitor Bank Manual Inspection	2,304	6,103	10,477	15,107	20,006	25,186	56,599	135,782
Better Utilization of Substation Capital	2,241	6,207	10,345	14,483	18,621	23,103	29,655	104,655
Reduced RTU Maintenance Cost	2,434	6,739	11,232	15,725	20,218	25,086	32,199	113,634
Savings from Increased Crew Productivity	1,503	4,343	7,262	10,405	13,377	16,350	35,673	88,913
Reduction in Transformer Replacement Capital	1,471	3,782	6,303	8,825	11,346	13,867	30,256	75,849
Deferral of Capital Costs (Switches, Cap Banks, etc.)	1,030	2,649	4,415	6,181	7,947	9,713	21,192	53,127
Increased DPL Revenue from SA Related Reduced Outage Time	362	1,003	1,671	2,339	3,008	3,732	4,790	16,905
Savings from Reduction in Outage Related Calls	154	346	658	922	1,185	1,448	3,160	7,873
Increase in DPL Revenue due to DA Related Reduced Outage Time	152	392	653	914	1,175	1,436	3,132	7,852
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

4.2.2 Energy and Demand Savings

DP&L expects to begin to realize a reduction in line losses of 54,110 MWh through 2015. This reduction will be accomplished through the efficient placement of capacitor banks and modeling the distribution circuit which, with the help of the AMI information, will allow DP&L to reduce energy losses on the distribution system.

Elements of distribution and substation automation can also be leveraged to assist the reduction of power demands on peak load days. One of the operational characteristics of the distribution system that can be managed through distribution automation is the voltage profile along the feeder. Since loads are dynamic and the amount of current affects the voltage drop along the feeder, using voltage monitoring and dynamic switching of capacitors and regulators, it is possible to control the voltage profile. Based on successes at other utilities, DP&L expects

to be able to trigger voltage changes at peak times, also known as dynamic voltage control ("DVC"), thus reducing peak demand by 5.3 MW in year 2015.

Table 4.2.2 Summary of Energy and Demand Savings

Energy Savings (MWh)	1,405	2,823	4,086	5,508	6,926	8,339	25,023	54,110
Demand Savings (MW)	0.3	0.6	0.9	1.2	1.5	1.8	5.3	

5 Deployment Schedule

In order to test properly equipment and the horizontal integration of this equipment, DP&L will slowly phase in distribution and substation automation technologies in a coordinated manner. Final circuit and substation selection has not been completed; however DP&L expects to prioritize installation based on existing reliability concerns and on the potential for highest customer impact.

Table 5 Deployment Schedule

# of Distribution Circuits Automated	4	4	4	4	4	4	48	72
# of Substations Automated	6	6	6	6	6	7	12	49

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Overall Financial Summary

Schedule A-1
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Line	Year	1 2009	2 2010	3 2011	4 2012	5 2013	6 2014	7 2015	Source:
1	Infrastructure Revenue Recovery	$ 47,426,587	$ 47,426,587	$ 47,426,587	$ 47,426,587	$ 47,426,587	$ 47,426,587	$ 47,426,587	Schedule A-2, line 31
2									
3									
4	Energy Efficiency Net Revenue Requirements	$ 13,006,224	$ 23,471,717	$ 33,742,626	$ 43,103,981	$ 54,903,703	$ 67,067,805	$ 77,365,431	Schedule A-3, line 27
5									
6									
7	Total	$ 60,432,811	$ 70,898,304	$ 81,169,213	$ 90,530,568	$ 102,330,290	$ 114,494,391	$ 124,792,018	Line 1 + Line 4
8									
9									
10	Total All Years							$ 644,647,594	Sum of Line 9

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Infrastructure Investment Rider Revenue Requirements

Schedule A-2
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Line		2009 O&M/Debt	2009 Equity	2010 O&M/Debt	2010 Equity	2011 O&M/Debt	2011 Equity	2012 O&M/Debt	2012 Equity	2013 O&M/Debt	2013 Equity	2014 O&M/Debt	2014 Equity	2015 O&M/Debt	2015 Equity	Source:
1	IIR Rate Base		59,892,316		105,858,549		136,859,744		157,300,119		178,279,548		189,964,287		184,851,834	Schedule B-1, line 14
2																
3	Cost of Debt/Equity	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	Schedule D-1
4																
5	Return on Rate Base	1,199,815	4,387,385	2,127,757	7,780,603	2,750,881	10,059,191	3,161,732	11,561,559	3,583,419	13,103,547	3,818,282	13,962,374	3,715,518	13,588,595	Line 1 x Line 3
6																
7	O&M	1,182,810		4,355,250		9,124,834		12,121,003		13,035,143		13,869,018		13,722,224		Schedule C-1, line 2
8																
9	Depreciation Expense	1,256,154		3,984,357		9,843,463		15,091,886		17,424,345		19,994,199		22,650,304		Schedule C-1, line 4
10																
11	Taxes Other than Income	-		2,798,459		5,585,944		10,133,345		11,482,291		13,321,812		14,731,920		Schedule C-1, line 6
12																
13	Deferred CCEM Costs - Infrastructure	$ 2,273,759		$ 2,486,583		$ 2,719,328										Schedule C-5, lines 33, 39, 45
14																
15	Stranded Investment Value	273,670		4,968,238		1,802,444		6,491,838		2,567,263		2,378,656		29,547		Schedule B-8, line 8
16																
17	Rate Case Expense	$ 381,982		$ 395,883		$ 432,916		0		0		0		0		Schedule C-5, lines 14, 18, 21
18																
19	Revenue Requirements excl of Income Taxes	6,548,208	4,387,385	21,116,507	7,780,603	32,259,909	10,059,191	46,999,805	11,561,559	48,112,461	13,103,547	53,382,168	13,962,374	54,849,613	13,588,595	Sum Line 5 thru 17
20																
21	Gross Revenue Conversion Factor	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	Schedule A-4, line 28
22																
23	Annual Revenue Requirements	6,685,713	6,927,681	21,558,954	12,285,573	32,937,367	15,883,463	47,966,800	18,255,701	49,122,623	20,690,501	54,503,193	22,046,588	56,001,353	21,453,234	Line 19 x Line 21
24																
25	Total Annual Revenue Requirements		$ 13,613,383		$ 33,845,527		$ 48,820,830		$ 66,242,502		$ 69,813,323		$ 76,549,781		$ 77,454,586	Sum Col A & B, Line 23
26																
27	Shared Savings		$ (70,171)		$ (574,989)		$ (1,669,406)		$ (4,245,480)		$ (6,322,287)		$ (8,388,083)		$ (9,835,800)	Schedule C-5, Line 5
28																
29	Net Infrastructure Revenue Requirements		$ 13,543,223		$ 33,270,538		$ 47,151,422		$ 61,997,022		$ 63,491,036		$ 68,161,699		$ 67,618,786	Line 25 + Line 27
30																
31	IIR Rev Req Adjusted for Time Value of Money		$ 47,426,587		$ 47,426,587		$ 47,426,587		$ 47,426,587		$ 47,426,587		$ 47,426,587		$ 47,426,587	Schedule E-1, line 55

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Energy Efficiency Rider Revenue Requirements

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Work Paper Reference No(s): None

Witness Responsible:
Dona Seger-Lawson

Line		2009 O&M/Debt	2009 Equity	2010 O&M/Debt	2010 Equity	2011 O&M/Debt	2011 Equity	2012 O&M/Debt	2012 Equity	2013 O&M/Debt	2013 Equity	2014 O&M/Debt	2014 Equity	2015 O&M/Debt	2015 Equity	Source:
1	EER Rate Base		-		498,323		476,231		459,086		440,846		423,415		408,741	Schedule B-1, line 29
3	Cost of Debt/Equity	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	2.01%	7.35%	Schedule D-1
5	Return on Rate Base	-	-	10,016	36,627	9,612	35,150	9,228	33,744	8,861	32,402	8,511	31,121	8,176	29,895	Line 1 x Line 3
7	O&M	8,968,078		13,512,652		16,485,389		17,751,721		19,539,193		20,723,309		21,457,259		Schedule C-1, line 12
9	Depreciation Expense	-		-		11,283		11,283		11,283		11,283		11,283		Schedule C-1, line 14
11	Taxes Other than Income	-		-		32,132		30,820		29,509		28,197		26,886		Schedule C-1, line 16
13	Deferred Costs - Energy Efficiency	$ 482,433		$ 505,717		$ 553,052										Schedule C-8, lines 32, 38, 44
15	Revenue Requirements exclusive of Income Taxes	9,450,511	-	14,028,385	36,627	17,071,468	35,150	17,803,052	33,744	19,588,846	32,402	20,771,300	31,121	21,503,584	29,895	Sum of Line 5 thru 13
17	Gross Revenue Conversion Factor	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	1.021	1.579	Schedule A-4, line 28
19	Annual Revenue Requirements	9,648,972	-	14,322,961	57,834	17,429,969	55,502	18,176,918	53,261	20,000,212	51,163	21,207,497	49,140	21,965,159	47,205	Line 15 x Line 17
21	Total Annual Revenue Requirements		$ 9,648,972		$ 14,380,615		$ 17,485,471		$ 18,230,197		$ 20,051,375		$ 21,256,637		$ 22,002,364	Sum of Col A & B Line 18
23	Lost Revenues		$ 3,357,253		$ 9,090,902		$ 16,257,155		$ 24,873,784		$ 34,852,328		$ 45,811,168		$ 55,363,067	Schedule C-5, line 2
25	Shared Savings		$ -		$ -		$ -		$ -		$ -		$ -		$ -	Schedule C-5, line 6
27	Net Energy Efficiency Revenue Requirements		$ 13,006,224		$ 23,471,717		$ 33,742,626		$ 43,103,981		$ 54,903,703		$ 67,067,805		$ 77,365,431	Sum lines 21 - 25

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Computation of Gross Revenue Conversion Factor

Data: 12 Months Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Witness Responsible:
C. T. Hergenrather

Line No.	Item Description	Equity Gross Revenues	O&M/Debt Gross Revenues	Source
	(A)	(B)	(C)	(D)
1	Operating Revenues	100.0000%	100.0000%	
2	Uncollectible Accounts Percent	1.7609%	1.7609%	Uncollectible Expense Worksheet
3	Operating Revenue After Uncollectible Expense	98.2391%	98.2391%	Line 1 - Line 2
4	Less: Commercial Actitivies Tax (CAT)	0.26%	0.26%	Statutory Rate as of April 1, 2009
5	Percentage of Income After CAT	97.98%	97.98%	Line 3 - Line 4
6	Less: Kentucky Income Tax (KIT)			
7	KIT Apportionment Factor	1.3606%	0.0000%	Kentucky Corporation Income Tax Return - Form 720
8	KIT Marginal Tax Rate (KY Corp Income and License Tax)	7.0000%	7.0000%	Kentucky Corporation Income Tax Return - Form 720
9	Effective KIT Rate	0.0952%	0.0000%	Line 7 * Line 8
10	Effective KIT Rate	0.0933%	0.0000%	Line 5 * Line 9
11	Percentage of Income After KIT	97.8858%	97.9791%	Line 5 - Line 10
12	Less: Ohio Franchise Tax Return (OFT)			
13	OFT Apportionment Factor	0.0000%	0.0000%	Ohio Franchise Tax Return - Form OH 1120
14	OFT Tax Rate	8.5000%	8.5000%	Ohio Franchise Tax Return - Form OH 1120
15	Effective OFT Tax Rate	0.0000%	0.0000%	Line 13 * Line 14
16	Effective OFT Rate	0.0000%	0.0000%	Line 11 * Line 15
17	Percentage of Income After OFT	97.8858%	97.9791%	Line 11 - Line 16
18	Less: Ohio Municipal Income Tax Return			
19	Municipal Income Tax Due	$1,772,102	$0	Municipal Tax Worksheet
20	Federal Taxable Income	$361,735,026	$361,735,026	2006 Federal Tax Return
21	Effective Ohio Municipal Tax Rate	0.4899%	0.0000%	Line 19 / Line 20
22	Effective Ohio Municipal Tax Rate as a Percent of Line 15	0.4795%	0.0000%	Line 17 * Line 21
23	Percentage of Income Before Federal Income Tax	97.4063%	97.9791%	Line 17 - Line 22
24	Less: Federal Income Tax (FIT)			
25	FIT Marginal Rate	35.0000%	0.0000%	2006 Federal Tax Return
26	Effective Marginal Rate	34.0922%	0.0000%	Line 23 * Line 25
27	Net Operating Income Percentage (Line 23 - Line 26)	63.3141%	97.9791%	Line 23 - Line 26
28	Gross Revenue Conversion Factor (Line 1 / Line 27)	1.579	1.021	Line 1 / Line 27

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Rate Base Summary

Schedule B-1
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: 12 Months Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Line	Year	1	2	3	4	5	6	7	
		2009	2010	2011	2012	2013	2014	2015	Source:
1	**Infrastructure Investment Rider**								
2	Gross Plant in Service	45,162,741	91,391,119	167,280,387	195,995,043	233,706,743	265,373,889	296,600,839	Schedule B-2, line 16
3									
4	Accumulated Depreciation	(1,256,164)	(5,240,520)	(15,083,983)	(30,175,868)	(47,600,213)	(67,594,411)	(90,244,715)	Schedule B-3, line 16
5									
6	Net Plant in Service	43,906,577	86,150,599	152,196,404	165,819,175	186,106,530	197,779,478	206,356,124	Line 1 + Line 3
7									
8	Rate Base Adjustments								
9	NBV of Stranded Equipment Less Salvage	(273,670)	(4,966,238)	(1,802,444)	(6,491,838)	(2,587,263)	(2,378,858)	(29,547)	Schedule B-8, line 8
10	Deferred Taxes Net of Retirements	(489,452)	(3,053,452)	(19,414,777)	(16,906,107)	(19,762,143)	(18,814,076)	(21,489,208)	Schedule B-7, line 16
11	Construction Work in Progress	16,548,856	27,729,640	5,880,562	14,878,889	14,522,425	13,377,722	14,264	Schedule B-4, line 12
12	Total Adjustments	15,785,733	19,707,951	(15,336,659)	(8,519,055)	(7,826,980)	(7,815,211)	(21,504,490)	Sum Lines 9 thru 11
13									
14	Total Infrastructure Investment Rider Rate Base	59,692,310	105,858,549	136,859,744	157,300,119	178,279,549	189,964,267	184,851,634	Line 6 + Line 12
15									
16	**Energy Efficiency Rider**								
17	Gross Plant in Service	0	504,950	504,950	504,950	504,950	504,950	504,950	Schedule B-2, line 8
18									
19	Accumulated Depreciation	0	0	(11,283)	(22,566)	(33,848)	(45,131)	(56,414)	Schedule B-3, line 8
20									
21	Net Plant in Service	0	504,950	493,667	482,384	471,102	459,819	448,536	Line 17 + Line 19
22									
23	Rate Base Adjustments								
24	Net Book Value of Stranded Equipment	0	0	0	0	0	0	0	Not Applicable
25	Deferred Taxes Net of Retirements	0	(6,627)	(15,436)	(23,288)	(30,255)	(36,404)	(41,795)	Schedule B-7, line 7
26	Construction Work in Progress	0	0	0	0	0	0	0	Schedule B-4, line 11
27	Total Adjustments	0	(6,627)	(15,436)	(23,288)	(30,255)	(36,404)	(41,795)	Sum Line 24 thru 26
28									
29	Total Energy Efficiency Rider Rate Base	0	498,323	478,231	459,096	440,846	423,415	406,741	Line 21 + Line 27
30									

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Plant In-Service - New Property

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPB-2.1b & WPB-2.1c

Schedule B-2
Page 1 of 1
Witness Responsible:
G. S. Campbell

Line No.	Major Program	Function	Balance at 12/31/2009	Balance at 12/31/2010	Balance at 12/31/2011	Balance at 12/31/2012	Balance at 12/31/2013	Balance at 12/31/2014	Balance at 12/31/2015	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Gross Plant (Account 101)									
2										
3	Energy Efficiency:									
4										
5		Intangible Property	0	0	0	0	0	0	0	
6		Distribution Property	0	504,950	504,950	504,950	504,950	504,950	504,950	See below
7										
8		Total	0	504,950	504,950	504,950	504,950	504,950	504,950	Sum of Lines 5 and 6
9										
10										
11	Infrastructure:									
12										
13		Intangible Property	2,062,500	10,971,886	64,205,954	65,999,618	75,347,503	80,151,609	97,967,571	See below
14		Distribution Property	43,100,241	80,419,233	103,074,433	129,995,425	158,359,240	185,222,280	198,633,268	See below
15										
16		Total	45,162,741	91,391,119	167,280,387	195,995,043	233,706,743	265,373,889	296,600,839	Sum of Lines 13 and 14
17										
18										
19	Total									
20										
21		Intangible Property	2,062,500	10,971,886	64,205,954	65,999,618	75,347,503	80,151,609	97,967,571	Sum of Lines 5 and 13
22		Distribution Property	43,100,241	80,924,183	103,579,383	130,500,375	158,864,190	185,727,230	199,138,218	Sum of Lines 6 and 14
23										
24		Total	45,162,741	91,896,069	167,785,337	196,499,993	234,211,693	265,878,839	297,105,789	Sum of Lines 21 and 22
25										
26										
27		Source:								
28		Line 6, Cols. (D) through (J) from WPB-2.1b Page 1 of 7 (Line 9) through Page 7 of 7. Each page is a different calendar year.								
29		Line 13, Cols. (D) through (J) from WPB-2.1c Page 1 of 7 (Line 2 + Line 13) through Page 7 of 7. Each page is a different calendar year.								
30		Line 14, Cols. (D) through (J) from WPB-2.1c Page 1 of 7 (Line 28 - Line 2 - Line 13) through Page 7 of 7. Each page is a different calendar year.								

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Reserve for Accumulated Depreciation and Amortization - New Property

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPB-3.1b & WPB-3.1c

Schedule B-3
Page 1 of 1
Witness Responsible:
G. S. Campbell

Line No.	Major Program	Function	Balance at 12/31/2009	Balance at 12/31/2010	Balance at 12/31/2011	Balance at 12/31/2012	Balance at 12/31/2013	Balance at 12/31/2014	Balance at 12/31/2015	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Reserve for Accumulated Depreciation (Account 108) and Reserve for Accumulated Amortization (Account 111)									
2										
3	Energy Efficiency:									
4										
5		Intangible Property	0	0	0	0	0	0	0	
6		Distribution Property	0	0	11,283	22,566	33,848	45,131	56,414	See below
7										
8		Total	0	0	11,283	22,566	33,848	45,131	56,414	Sum of Lines 5 and 6
9										
10										
11	Infrastructure:									
12										
13		Intangible Property	147,321	1,078,349	6,448,195	15,748,593	25,844,816	36,951,895	49,674,694	See below
14		Distribution Property	1,108,842	4,162,171	8,635,789	14,427,276	21,755,398	30,642,516	40,570,021	See below
15										
16		Total	1,256,164	5,240,520	15,083,983	30,175,868	47,600,213	67,594,411	90,244,715	Sum of Lines 13 and 14
17										
18										
19	Total									
20										
21		Intangible Property	147,321	1,078,349	6,448,195	15,748,593	25,844,816	36,951,895	49,674,694	Sum of Lines 5 and 13
22		Distribution Property	1,108,842	4,162,171	8,647,071	14,449,841	21,789,246	30,687,647	40,626,435	Sum of Lines 6 and 14
23										
24		Total	1,256,164	5,240,520	15,095,266	30,198,434	47,634,062	67,639,542	90,301,129	Sum of Lines 21 and 22
25										
26		Source:								
27		Line 6, Cols. (D) through (J) from WPB-3.1b Page 1 of 7 (Line 5, Col. (K)) through Page 7 of 7. Each page is a different calendar year.								
28		Line 13, Cols. (D) through (J) from WPB-3.1c Page 1 of 7, Col. (K), (Line 2 + Line 10) through Page 7 of 7. Each page is a different calendar year.								
29		Line 14, Cols. (D) through (J) from WPB-3.1c Page 1 of 7, Col. (K), (Line 23 - Line 2 - Line 10) through Page 7 of 7. Each page is a different calendar year.								

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Construction Work In-Progress

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPB-4

Schedule B-4
Page 1 of 1
Witness Responsible:
G. S. Campbell

Line No.		Major Program	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Total CWIP Balance at December 31:									
2										
3		Energy Efficiency	0	0	0	0	0	0	0	WPB-4 Col. (I)
4		Infrastructure	22,329,944	37,735,513	7,993,693	20,273,653	19,956,831	18,520,887	19,018	WPB-4 Col. (I)
5										
6		Total	22,329,944	37,735,513	7,993,693	20,273,653	19,956,831	18,520,887	19,018	Sum of Lines 3 and 4
7										
8										
9	CWIP in Rate Base at December 31:									
10										
11		Energy Efficiency	0	0	0	0	0	0	0	WPB-4 Col. (J)
12		Infrastructure	16,548,856	27,729,640	5,880,562	14,878,889	14,522,425	13,377,722	14,264	WPB-4 Col. (J)
13										
14		Total	16,548,856	27,729,640	5,880,562	14,878,889	14,522,425	13,377,722	14,264	Sum of Lines 11 and 12
15										
16										
17	Allowance for Funds Used During Construction (AFUDC):									
18										
19		Energy Efficiency	0	4,950	0	0	0	0	0	WPB-4 Col. (F)
20		Infrastructure	264,803	673,746	1,040,589	282,665	323,909	438,060	379,202	WPB-4 Col. (F)
21										
22		Total	264,803	678,696	1,040,589	282,665	323,909	438,060	379,202	Sum of Lines 19 and 20
23										
24										

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Net Book Value of Assets Prematurely Retired

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPB-5.1b & WPB-5.1c

Schedule B-5
Page 1 of 1
Witness Responsible:
G. S. Campbell

Line No.	Major Program	Function	Activity for Year 2009	Activity for Year 2010	Activity for Year 2011	Activity for Year 2012	Activity for Year 2013	Activity for Year 2014	Activity for Year 2015	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Net Book Value at Time of Retirement:									
2										
3	Energy Efficiency:									
4		Intangible Property	0	0	0	0	0	0	0	WPB-5.1b
5		Distribution Property	0	0	0	0	0	0	0	WPB-5.1b
6		Total	0	0	0	0	0	0	0	Sum of Lines 4 and 5
7										
8	Infrastructure:									
9		Intangible Property	0	0	0	3,758,145	0	0	0	See below
10		Distribution Property	274,816	4,994,217	1,811,037	2,746,869	2,601,585	2,393,180	29,736	See below
11		Total	274,816	4,994,217	1,811,037	6,505,014	2,601,585	2,393,180	29,736	Sum of Lines 9 and 10
12										
13	Total Net Book Value									
14		Intangible Property	0	0	0	3,758,145	0	0	0	Sum of Lines 4 and 9
15		Distribution Property	274,816	4,994,217	1,811,037	2,746,869	2,601,585	2,393,180	29,736	Sum of Lines 5 and 10
16		Total	274,816	4,994,217	1,811,037	6,505,014	2,601,585	2,393,180	29,736	Sum of Lines 14 and 15
17										
18	Estimated Salvage Credits:									
19										
20	Energy Efficiency:									
21		Intangible Property	0	0	0	0	0	0	0	WPB-5.1b
22		Distribution Property	0	0	0	0	0	0	0	WPB-5.1b
23		Total	0	0	0	0	0	0	0	Sum of Lines 21 and 22
24										
25	Infrastructure:									
26		Intangible Property	0	0	0	0	0	0	0	See below
27		Distribution Property	1,146	25,979	8,593	13,176	14,322	14,322	189	See below
28		Total	1,146	25,979	8,593	13,176	14,322	14,322	189	Sum of Lines 26 and 27
29										
30	Total Salvage Credits									
31		Intangible Property	0	0	0	0	0	0	0	Sum of Lines 21and 26
32		Distribution Property	1,146	25,979	8,593	13,176	14,322	14,322	189	Sum of Lines 22 and 27
33		Total	1,146	25,979	8,593	13,176	14,322	14,322	189	Sum of Lines 31 and 32
34										
35		Source:								
36		Line 9 from WPB-5.1c, Col. (F) (Line 2 + Line 10), page 1 of 7 through 7 of 7. Each page is a different calendar year.								
37		Line 10 from WPB-5.1c, Col. (F) (Line 23 - Line 2 - Line 10), page 1 of 7 through 7 of 7. Each page is a different calendar year.								
38		Line 26 from WPB-5.1c, Col. (G) (Line 2 + Line 10), page 1 of 7 through 7 of 7. Each page is a different calendar year.								
39		Line 27 from WPB-5.1c, Col. (G) (Line 23 - Line 2 - Line 10), page 1 of 7 through 7 of 7. Each page is a different calendar year.								

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Allowance for Funds Used During Construction
As of June 30, 2008

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPB-6

Witness Responsible:
G. S. Campbell

Line No.	Funding Source	Capitalization Amount in $000)	Capitalization Ratio	Cost Rates	Short Term Debt / CWIP	Weighted Cost Rates	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	Weighted Average Short-Term Debt Balance	0		0.0000%	0.000%	0.0000%	WPB-6
2							
3	Capitalization:						
4							
5	Average Long-Term Debt Balance (a)	448,700	23.6168%	5.8643%	100.000%	1.3850%	See below
6							
7	Average Preferred Stock Balance	20,755	1.0924%	4.1800%	100.000%	0.0457%	Schedule JDM D-1
8							
9	Average Common Equity Balance	1,430,469	75.2908%	11.3000%	100.000%	8.5079%	Schedule JDM D-1
10							
11	Total Capitalization	1,899,924	100.0000%			9.9385%	Sum of Lines 5-9
12							
13							
14					Maximum AFUDC Rate:	9.94%	Line 11 Column (G) rounded
15							
16					AFUDC Rate to be Used:	8.80%	
17							

18 a) Balance excludes long-term debt associated with pollution control bonds for which debt/interest is assigned directly to assets.
19
20 Source:
21 Line 5 Cols. (C) & (E) from WPB-6
22 Line 5, 7, 9, Col. (D) is the ratio each respective line of Col. (C) to the Total Capitalization (Line 11, Col. (C))

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Deferred Income Taxes - New Property Net of Retirements

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): XXXX

Witness Responsible:
C.T. Hergenrather

Line No.	Major Program	Function	Balance at 12/31/2009	Balance at 12/31/2010	Balance at 12/31/2011	Balance at 12/31/2012	Balance at 12/31/2013	Balance at 12/31/2014	Balance at 12/31/2015	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
1	Energy Efficiency:									
2										
3		Net Tax Basis	0	486,014	449,563	415,846	384,658	355,808	329,123	Work Paper WPB-7.1
4		Net Book Basis	0	504,950	493,667	482,384	471,102	459,819	448,536	Sch. B-2 - Sch. B-3
5		Net Basis Difference	0	(18,936)	(44,104)	(66,538)	(86,444)	(104,011)	(119,414)	Lines 3 + Line 4
6		Statutory Tax Rate	35%	35%	35%	35%	35%	35%	35%	Statutory Tax Rate
7		Deferred Income Tax	0	(6,627)	(15,436)	(23,288)	(30,255)	(36,404)	(41,795)	Line 5 * Line 6
8										
9										
10	Infrastructure:									
11										
12		Net Tax Basis	42,233,326	72,432,234	94,914,574	111,010,998	127,041,680	141,631,796	144,928,652	Work Paper WPB-7.1
13		Net Book Basis	43,631,761	81,156,382	150,385,367	159,314,160	183,504,945	195,386,298	206,326,388	Sch. B-2 - Sch. B-3
14		Net Basis Difference	(1,398,436)	(8,724,148)	(55,470,792)	(48,303,162)	(56,463,265)	(53,754,502)	(61,397,736)	Line 12 + Line 13
15		Statutory Tax Rate	35%	35%	35%	35%	35%	35%	35%	Statutory Tax Rate
16		Deferred Income Tax	(489,452)	(3,053,452)	(19,414,777)	(16,906,107)	(19,762,143)	(18,814,076)	(21,489,208)	Line 14 * Line 15
17										
18										
19	Total									
20										
21		Net Tax Basis	42,233,326	72,918,248	95,364,138	111,426,844	127,426,338	141,987,604	145,257,775	Line 3 + Line 12
22		Net Book Basis	43,631,761	81,661,332	150,879,034	159,796,545	183,976,046	195,846,117	206,774,924	Line 4 + Line 13
23		Net Basis Difference	(1,398,436)	(8,743,084)	(55,514,896)	(48,369,701)	(56,549,709)	(53,858,513)	(61,517,149)	Line 21 + Line 22
24		Statutory Tax Rate	35%	35%	35%	35%	35%	35%	35%	Statutory Tax Rate
25		Deferred Income Tax	(489,452)	(3,060,079)	(19,430,214)	(16,929,395)	(19,792,398)	(18,850,480)	(21,531,002)	Line 23 * Line 24
26										
27										

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Stranded Cost Calculation

Schedule B-8
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: 12 Months Actual
Type of Filing: Original
Work Paper Reference No(s).: None

	Year	1	2	3	4	5	6	7	
Line		2009	2010	2011	2012	2013	2014	2015	Source:
1	Net Book Value at time of Retirement								
2	Total Net Book Value of Retirements	274,816	4,994,217	1,811,037	6,505,014	2,601,585	2,393,180	29,736	Schedule B-5, Line 11
3									
4	Salvage Value of Assets								
5	Total Salvage Value	1,146	25,979	8,593	13,176	14,322	14,322	189	Schedule B-5, line 28
6									
7									
8	Total Stranded Cost Value	273,670	4,968,238	1,802,444	6,491,838	2,587,263	2,378,858	29,547	Line 2 - Line 5
9									
10									

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Expense Summary

Schedule C-1
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Line	Year	1	2	3	4	5	6	7	
		2009	2010	2011	2012	2013	2014	2015	Source:
1	**Infrastructure Investment Rider**								
2	O&M	1,182,810	4,355,250	9,124,934	12,121,003	13,035,143	13,869,018	13,722,224	Schedule C-2, line 30
3									
4	Depreciation Expense	1,256,164	3,984,357	9,843,463	15,091,886	17,424,345	19,994,198	22,650,304	Schedule C-3, line 8
5									
6	Taxes Other than Income	0	2,798,459	5,585,944	10,133,345	11,482,291	13,321,812	14,731,920	Schedule C-4, line 8
7									
8	Total Infrastructure Investment Expenses	2,438,974	11,138,066	24,554,341	37,346,234	41,941,779	47,185,028	51,104,448	Sum of Lines 2 thru 7
9									
10									
11	**Energy Efficiency Rider**								
12	O&M	8,988,078	13,512,652	16,465,389	17,751,721	19,539,193	20,723,309	21,457,239	Schedule C-2, line 11
13									
14	Depreciation Expense	-	-	11,283	11,283	11,283	11,283	11,283	Schedule C-3, line 2
15									
16	Taxes Other than Income	-	-	32,132	30,820	29,509	28,197	26,886	Schedule C-4, line 2
17									
18	Total Energy Efficiency Expenses	8,988,078	13,512,652	16,508,804	17,793,824	19,579,985	20,762,789	21,495,408	Sum of Lines 12 thru 17
19									
20									
21	Total	11,427,052	24,650,718	41,063,145	55,140,058	61,521,764	67,947,817	72,599,856	Line 8 + Line 18
22									

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Operations and Maintenance Expense and Related Fringe Costs by Account

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-2

Schedule C-2
Page 1 of 2
Witness Responsible:
G.S. Campbell

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		Energy Efficiency:									
2	911	Supervision	430,313	786,671	1,077,142	1,118,644	1,209,378	1,246,849	1,279,881	7,148,877	WPC-2, Page 1
3	912	Demonstration and Selling Expenses	860,625	1,573,341	2,154,283	2,237,288	2,418,757	2,493,698	2,559,761	14,297,754	WPC-2, Page 1
4	913	Advertising Expenses	860,625	1,573,341	2,154,283	2,237,288	2,418,757	2,493,698	2,559,761	14,297,754	WPC-2, Page 1
5	916	Miscellaneous Sales Expenses	6,616,472	9,349,681	10,840,366	11,909,361	13,233,206	14,219,876	14,778,421	80,947,385	WPC-2, Page 1
6											
7	925	Injuries and Damages	5,740	5,884	6,031	6,181	6,336	6,494	6,657	43,322	WPC-2, Page 1
8	926	Employee Pensions and Benefits	164,536	172,375	180,283	188,260	196,310	204,433	212,634	1,318,831	WPC-2, Page 1
9	408.1	Taxes Other Than Income Taxes	49,768	51,359	53,002	54,698	56,449	58,258	60,125	383,657	WPC-2, Page 1
10											
11		Total EE Programs	8,988,078	13,512,652	16,465,389	17,751,721	19,539,193	20,723,309	21,457,239	118,437,581	Sum of Lines 2 - 11
12											
13											
14		Infrastructure (IT and Delivery):									
15	580	Operation Supervision and Engineering	34,389	125,793	187,685	213,773	232,227	248,205	236,566	1,278,637	WPC-2, Page 2
16	586	Meter Expenses	6,878	25,159	37,537	42,755	46,445	49,641	47,313	255,727	WPC-2, Page 2
17	587	Customer Installations Expenses	412,662	1,509,612	2,252,225	2,565,272	2,788,726	2,978,457	2,838,792	15,343,646	WPC-2, Page 2
18	588	Miscellaneous Expenses	233,842	855,390	1,276,261	1,453,654	1,579,145	1,687,792	1,608,649	8,694,733	WPC-2, Page 2
19	590	Maintenance Supervision and Engineer.	3,526	12,898	19,244	21,919	23,812	25,450	24,256	131,106	WPC-2, Page 2
20	597	Maintenance of Meters	66,995	245,067	365,645	416,468	452,421	483,548	460,873	2,491,016	WPC-2, Page 2
21	920	Administrative and General Salaries	-	-	1,288,342	2,331,910	2,669,364	2,773,634	2,838,528	11,921,777	WPC-2, Page 2
22	921	Office Supplies and Expenses (Travel)	32,289	20,126	105,417	37,599	8,282	15,132	-	218,845	WPC-2, Page 2
23	923	Outside Services Employed	261,478	162,984	853,360	304,360	67,040	122,491	-	1,771,713	WPC-2, Page 2
24	935	Maintenance of General Plant	-	1,208,220	2,028,941	3,575,046	3,807,997	4,069,462	4,246,909	18,936,575	WPC-2, Page 2
25											
26	925	Injuries and Damages	3,315	4,780	19,379	31,838	36,855	38,776	39,058	174,001	WPC-2, Page 2
27	926	Employee Pensions and Benefits	97,103	142,059	546,046	898,860	1,048,175	1,111,822	1,123,476	4,967,531	WPC-2, Page 2
28	408.1	Taxes Other Than Income Taxes	30,334	43,262	144,851	227,560	256,652	264,610	257,803	1,225,073	WPC-2, Page 2
29											
30		Total Infrastructure	1,182,810	4,355,250	9,124,934	12,121,003	13,035,143	13,869,018	13,722,224	67,410,382	Sum of Lines 15 - 28
31											
32											
33											

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Operations and Maintenance Expense and Related Fringe Costs by Account

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-2

Schedule C-2
Page 2 of 2
Witness Responsible:
G.S. Campbell

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		Grand Total:									
2	580	Operation Supervision and Engineering	34,389	125,793	187,685	213,773	232,227	248,205	236,566	1,278,637	Line 15
3	586	Meter Expenses	6,878	25,159	37,537	42,755	46,445	49,641	47,313	255,727	Line 16
4	587	Customer Installations Expenses	412,662	1,509,512	2,252,225	2,565,272	2,786,726	2,978,457	2,838,792	15,343,646	Line 17
5	588	Miscellaneous Expenses	233,842	855,390	1,276,261	1,453,654	1,579,145	1,687,792	1,608,649	8,694,733	Line 18
6	590	Maintenance Supervision and Engineer.	3,526	12,898	19,244	21,919	23,812	25,450	24,256	131,106	Line 19
7	597	Maintenance of Meters	66,995	245,067	365,645	416,468	452,421	483,548	460,873	2,491,016	Line 20
8	911	Supervision	430,313	786,671	1,077,142	1,118,644	1,209,378	1,246,849	1,279,881	7,148,877	Line 2
9	912	Demonstration and Selling Expenses	860,625	1,573,341	2,154,283	2,237,288	2,418,757	2,493,698	2,559,761	14,297,754	Line 3
10	913	Advertising Expenses	860,625	1,573,341	2,154,283	2,237,288	2,418,757	2,493,698	2,559,761	14,297,754	Line 4
11	916	Miscellaneous Sales Expenses	6,616,472	9,349,681	10,840,366	11,909,361	13,233,206	14,219,878	14,778,421	80,947,385	Line 5
12	920	Administrative and General Salaries	-	-	1,288,342	2,331,910	2,689,364	2,773,634	2,838,528	11,921,777	Line 21
13	921	Office Supplies and Expenses (Travel)	32,269	20,126	105,417	37,599	8,282	15,132	-	218,845	Line 22
14	923	Outside Services Employed	261,478	162,984	853,360	304,360	67,040	122,491	-	1,771,713	Line 23
15	935	Maintenance of General Plant	-	1,208,220	2,028,941	3,575,046	3,807,997	4,069,462	4,246,909	18,936,575	Line 24
16											
17	925	Injuries and Damages	9,055	10,664	25,410	38,019	43,191	45,270	45,714	217,324	Sum of Lines 7 and 26
18	926	Employee Pensions and Benefits	261,638	314,434	726,329	1,087,110	1,244,485	1,316,255	1,338,110	6,288,362	Sum of Lines 8 and 27
19	408.1	Taxes Other Than Income Taxes	80,102	94,621	197,853	282,258	313,101	322,867	317,928	1,608,730	Sum of Lines 9 and 28
20											
21		Grand Total	10,170,888	17,867,902	25,590,323	29,872,724	32,574,336	34,592,327	35,179,463	185,847,963	Sum of Lines 35 - 52

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Operations and Maintenance Expense Decreased Costs by Account

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-2.4

Schedule C-2.1
Page 1 of 1
Witness Responsible:
G.S. Campbell

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		Energy Efficiency Savings (DSM)	-	-	-	-	-	-	-	-	WPC-2.4
2											
3											
4		Infrastructure Savings (IT and Delivery):									
5	580	Operation Supervision and Engineering	5,986	39,722	108,584	211,969	339,668	472,043	546,868	1,724,841	WPC-2.4
6	586	Meter Expenses	1,197	7,944	21,717	42,394	67,934	94,409	109,374	344,968	WPC-2.4
7	587	Customer Installations Expenses	71,837	476,666	1,303,006	2,543,624	4,076,018	5,664,513	6,562,421	20,698,086	WPC-2.4
8	588	Miscellaneous Expenses	40,708	270,111	738,370	1,441,387	2,309,744	3,209,891	3,718,705	11,728,916	WPC-2.4
9	590	Maintenance Supervision and Engineer.	614	4,073	11,134	21,734	34,828	48,401	56,074	176,858	WPC-2.4
10	597	Maintenance of Meters	11,663	77,386	211,541	412,953	661,735	919,625	1,065,399	3,360,301	WPC-2.4
11	923	Outside Services Employed	-	-	-	793,950	823,275	854,670	888,325	3,360,220	WPC-2.4
12	935	Maintenance of General Plant	-	-	-	762,815	790,990	821,154	853,488	3,228,447	WPC-2.4
13		Infrastructure Savings:	132,005	875,903	2,394,352	6,230,826	9,104,192	12,084,705	13,800,654	44,622,637	Sum of Lines 5 - 12
14											
15											
16		Grand Total Decreased Costs:									
17	580	Operation Supervision and Engineering	5,986	39,722	108,584	211,969	339,668	472,043	546,868	1,724,841	Line 5
18	586	Meter Expenses	1,197	7,944	21,717	42,394	67,934	94,409	109,374	344,968	Line 6
19	587	Customer Installations Expenses	71,837	476,666	1,303,006	2,543,624	4,076,018	5,664,513	6,562,421	20,698,086	Line 7
20	588	Miscellaneous Expenses	40,708	270,111	738,370	1,441,387	2,309,744	3,209,891	3,718,705	11,728,916	Line 8
21	590	Maintenance Supervision and Engineer.	614	4,073	11,134	21,734	34,828	48,401	56,074	176,858	Line 9
22	597	Maintenance of Meters	11,663	77,386	211,541	412,953	661,735	919,625	1,065,399	3,360,301	Line 10
23	923	Outside Services Employed	-	-	-	793,950	823,275	854,670	888,325	3,360,220	Line 11
24	935	Maintenance of General Plant	-	-	-	762,815	790,990	821,154	853,488	3,228,447	Line 12
25		Grand Total Decreased Costs:	132,005	875,903	2,394,352	6,230,826	9,104,192	12,084,705	13,800,654	44,622,637	Sum of Lines 17 - 24

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Depreciation and Amortization Increased Costs

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-3.1

Schedule C-3
Page 1 of 1
Witness Responsible:
G.S. Campbell

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		**Energy Efficiency:**									
2	403	Total DSM Depreciation	-	-	11,283	11,283	11,283	11,283	11,283	56,415	WPC-3.1, Page 1
3											
4											
5		**Total Infrastructure Deprec. and Amort.:**									
6	403	Depreciation Expense	1,108,843	3,053,330	4,473,617	5,791,488	7,328,122	8,887,119	9,927,505	40,570,024	WPC-3.1, Page 2
7	404	Amort. Of Limited-Term Electric Plant	147,321	931,027	5,369,846	9,300,398	10,096,223	11,107,079	12,722,799	49,674,693	WPC-3.1, Page 2
8		Infrastructure Deprec. and Amort.	1,256,164	3,984,357	9,843,463	15,091,886	17,424,345	19,994,198	22,650,304	90,244,717	Sum of Lines 6 and 7
9											
10											
11		**Grand Total:**									
12	403	Depreciation Expense	1,108,843	3,053,330	4,484,900	5,802,771	7,339,405	8,898,402	9,938,788	40,626,439	Sum of Lines 2 and 6
13	404	Amort. Of Limited-Term Electric Plant	147,321	931,027	5,369,846	9,300,398	10,096,223	11,107,079	12,722,799	49,674,693	Line 7
14		**Grand Total**	1,256,164	3,984,357	9,854,746	15,103,169	17,435,628	20,005,481	22,661,587	90,301,132	Sum of Lines 12 and 13

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Depreciation and Amortization Decreased Costs

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-3.2

Schedule C-3.1
Page 1 of 1
Witness Responsible:
G.S. Campbell

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		**Energy Efficiency:**									
2	403	Total DSM Depreciation	-	-	-	-	-	-	-	-	WPC-3.2, Page 1
3											
4											
5		**Total Infrastructure Deprec. and Amort.:**									
6	403	Depreciation Expense	8,336	241,377	528,604	726,234	965,546	1,119,418	1,208,531	4,798,046	WPC-3.2, Page 2
7	404	Amort. Of Limited-Term Electric Plant	-	-	-	870,697	909,670	854,091	785,350	3,419,808	WPC-3.2, Page 2
8		Infrastructure Deprec. and Amort.	8,336	241,377	528,604	1,596,931	1,875,216	1,973,509	1,993,881	8,217,854	Sum of Lines 6 and 7
9											
10											
11		**Grand Total:**									
12	403	Depreciation Expense Decrease	8,336	241,377	528,604	726,234	965,546	1,119,418	1,208,531	4,798,046	Sum of Lines 2 and 6
13	404	Amort. Of Limited-Term Elect. Plant Decrease	-	-	-	870,697	909,670	854,091	785,350	3,419,808	Line 7
14		**Grand Total Decreased Costs**	8,336	241,377	528,604	1,596,931	1,875,216	1,973,509	1,993,881	8,217,854	Sum of Lines 12 and 13

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Total Property Tax Increased Costs

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-4

Witness Responsible:
C.T. Hergenrather

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		**Energy Efficiency:**									
2	408.1	DSM Property Tax	-	-	32,132	30,820	29,509	28,197	26,886	147,544	WPC-4
3											
4											
5		**Infrastructure**									
6	408.1	Information Technology Property Tax	-	2,552,594	5,022,471	6,332,682	7,870,619	9,291,093	10,579,626	41,649,285	WPC-4
7	408.1	Delivery Property Tax	-	245,865	563,473	3,800,663	3,611,672	4,030,719	4,152,094	16,404,486	WPC-4
8	408.1	Infrastructure Property Tax	-	2,798,459	5,585,944	10,133,345	11,482,291	13,321,812	14,731,920	58,053,771	Sum of Lines 6 and 7
9											
10											
11	408.1	**Grand Total**	-	2,798,459	5,618,076	10,164,165	11,511,800	13,350,009	14,758,806	58,201,315	Sum of Lines 2 and 8

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Total Property Tax Decreased Costs

Data: 12 Months Forecast
Type of Filing: Original
Work Paper Reference No(s): WPC-4.2

Witness Responsible:
C.T. Hergenrather

Line No.	Account No.	Description	2009	2010	2011	2012	2013	2014	2015	Total	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) = (sum(D:J))	
1		**Energy Efficiency:**									
2	408.1	DSM Property Tax	-	-	-	-	-	-	-	-	WPC-4.2
3											
4											
5		**Infrastructure**									
6	408.1	Information Technology Property Tax	-	-	-	-	444,031	420,029	396,027	1,260,087	WPC-4.2
7	408.1	Delivery Property Tax	-	15,276	323,944	410,226	547,648	685,369	812,817	2,795,280	WPC-4.2
8	408.1	Infrastructure Property Tax	-	15,276	323,944	410,226	991,679	1,105,398	1,208,844	4,055,367	Sum of Lines 6 and 7
9											
10											
11	408.1	**Grand Total Property Tax Decrease**	-	15,276	323,944	410,226	991,679	1,105,398	1,208,844	4,055,367	Sum of Lines 2 and 8

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Lost Revenues and Shared Savings

Schedule C-5
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

	Year	1	2	3	4	5	6	7	
Line		2009	2010	2011	2012	2013	2014	2015	Source:
1	**Lost Revenues**								
2	Lost Revenues (EER)	3,357,253	9,090,902	16,257,155	24,873,784	34,852,328	45,811,168	55,363,067	Schedule C-5.1, line 8
3									
4	**Shared Savings**								
5	IIR Shared Savings	70,171	574,989	1,669,408	4,245,480	6,322,287	8,388,083	9,835,800	Schedule C-5.2, line 20
6	EER Shared Savings	-	-	-	-	-	-	-	Schedule C-5.2, line 9
7	Total Shared Savings	70,171	574,989	1,669,408	4,245,480	6,322,287	8,388,083	9,835,800	Line 5 + Line 6

The Dayton Power and Light Company
Book II - Customer Conservation and Energy Management
Case No. 08-1094-EL-SSO
Lost Revenues

Schedule C-5.1
Page 1 of 1
Witness Responsible:
John Wagner

Data: Forecasted
Type of Filing: Original
Work Paper Reference No(s).: None

Line No	Rate Description	2009	2010	2011	2012	2013	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Lost Revenue**							
2	Residential	1,707,579	4,650,132	8,137,238	12,404,171	17,233,335	22,532,018	26,642,369
3	Residential Heat	716,089	1,951,372	3,423,932	5,229,852	7,283,797	9,547,236	11,322,489
4	Secondary	675,246	1,794,651	3,431,684	5,288,220	7,545,291	10,020,123	12,690,791
5	Primary	224,443	598,576	1,091,993	1,689,363	2,420,799	3,227,788	4,101,094
6	Primary Substation	13,444	42,579	75,756	114,594	160,336	208,978	260,444
7	High Voltage	20,452	53,591	96,551	147,585	208,771	275,024	345,880
8	**Total**	**3,357,253**	**9,090,902**	**16,257,155**	**24,873,784**	**34,852,328**	**45,811,168**	**55,363,067**

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Shared Savings Calculation

Schedule C-5.2
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: 12 Months Actual
Data: Forecasted
Work Paper Reference No(s).: None

Line	Year	1	2	3	4	5	6	7	
		2009	2010	2011	2012	2013	2014	2015	Source:
1	**Energy Efficiency Savings**								
2	O&M	-	-	-	-	-	-	-	Schedule C-2.1, line 1
3	Depreciation Savings	-	-	-	-	-	-	-	Schedule C-3.1, line 2
4	Tax Savings	-	-	-	-	-	-	-	Schedule C-4.1, line 2
5	Total EER Savings	-	-	-	-	-	-	-	Sum of Lines 2 thru 4
6									
7	Shared %	50%	50%	50%	50%	50%	50%	50%	
8									
9	EER Shared Savings	-	-	-	-	-	-	-	Line 5 x Line 7
10									
11									
12	**Infrastructure Improvement Savings**								
13	O&M	132,005	875,903	2,394,352	6,230,826	9,104,192	12,084,705	13,800,654	Schedule C-2.1, line 13
14	Depreciation Savings	8,336	241,377	528,604	1,596,931	1,875,216	1,973,509	1,993,881	Schedule C-3.1, line 8
15	Tax Savings	-	15,276	323,944	410,226	991,679	1,105,398	1,208,844	Schedule C-4.1, line 8
16	DLC Capacity Savings	-	17,422	91,916	252,977	673,488	1,612,553	2,668,220	WPC-5.2, line 7
17	Total IIR Savings	140,341	1,149,978	3,338,816	6,490,960	12,644,575	16,776,165	19,671,599	Sum of Lines 13 thru 16
18	Shared %	50%	50%	50%	50%	50%	50%	50%	
19									
20	IIR Shared Savings	70,171	574,989	1,669,408	4,245,480	6,322,287	8,388,083	9,835,800	Line 17 x Line 18
21									

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Deferred Utility of the Future Costs

Schedule C-6
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Line		2007	2008 Thru April	2008 May -Dec	Total	Source:
1	Energy Efficiency		$ 57,566	$ 450,000	$ 507,566	Internal Documents
2						
3	IT		$ 50,044	$ 1,190,000	$ 1,240,044	Internal Documents
4						
5	T&D Infrastructure		$ 50,632	$ 1,205,000	$ 1,255,632	Internal Documents
6						
7	Common	$ 1,212,523	$ 1,767,637	$ 1,409,121	$ 4,389,281	Internal Documents
8						
9	Total	$ 1,212,523	$ 1,925,878	$ 4,254,121	$ 7,392,522	Line 1 + Line 3 + Line 5 + Line 7
10						
11	Cost of Capital	9.36%	9.36%	9.36%		Schedule D-1, Line 4, Col (E)
12	Plus Carrying Costs Year 1	$ 113,492			$ 113,492	Line 11 x Line 9 (2007)
13	Plus Carrying Costs Year 2	$ 124,115	$ 180,262	$ 398,186	$ 702,563	Line 11 x Line 9 (2007-2009)
14						2007=Line (9 + Line 12) x Line 11
15	Total Deferred Costs Pre 2009				$ 8,208,577	Line 9 + Line 12 + Line 13
16						
17	Directly Assignable Costs					
18	Energy Efficiency			17%	$ 555,074	Line 1 + (Line 1 x Line 11)
19	Infrastructure Investment			83%	$ 2,729,271	(Line 3 + Line 5) + [(Line 3 + Line 5) x Line 11]
20	Total Directly Assignable				$ 3,284,345	Line 18 + Line 19
21	Remaining Pre 2009 Costs				$ 4,924,233	Line 15 - Line 20
22	Assignment of Remaining Costs					
23	Energy Efficiency				$ 832,225	Line 20 x Line 24
24	Infrastructure Investment				$ 4,092,007	Line 21 x Line 24
25	Total Assigned Remaining Costs				$ 4,924,233	Line 23 + Line 24
26	Energy Efficiency Related Pre 2009 Costs				$ 1,387,299	Line 18 + Line 23
27	Infrastructure Investment Related Pre 2009 Costs				$ 6,821,278	Line 19 + Line 24
28						
29	Total Pre 2009 Costs				$ 8,208,577	Line 26 + Line 27
30						
31	First Year Collection-2009					
32	Energy Efficiency				$ 462,433	Line 26 * 1/3
33	Infrastructure Investment				$ 2,273,759	Line 27 * 1/3
34	Remaining Balance				$ 5,472,385	Line 29 - Line 32 - Line 33
35	Carrying Charge				$ 512,215	Line 34 * Line 11
36	Remaining Balance + Carrying Charge				$ 5,984,601	Line 34 + Line 35
37	Second Year Collection					
38	Year 2 EER Revenue Recovery				$ 505,717	Line 36 / 2 Yrs. Remaining * 17% (EE%)
39	Year 2 IIR Revenue Recovery				$ 2,486,583	Line 36 / 2 (Yrs. Remaining) * 83% (II%)
40	Remaining Balance				$ 2,992,300	Line 36 - Line 38 - Line 39
41	Carrying Charge				$ 280,079	Line 40 * Line 11
42	Remaining Balance + Carrying Charge				$ 3,272,380	Line 40 + Line 41
43	Third Year Collection					
44	Year 3 EER Revenue Recovery				$ 553,052	Line 42 * 17% (EE%)
45	Year 3 IIR Revenue Recovery				$ 2,719,328	Line 42 * 83% (II%)
46	Total Revenue Recovery					
47	EER Revenue Recovery				$ 1,521,202	Line 32 + Line 38 + Line 44
48	IIR Revenue Recovery				$ 7,479,670	Line 33 + Line 39 + Line 45
49	Total EER + IIR Revenue Recovery				$ 9,000,872	Line 47 + Line 48

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Deferred Utility of the Future Costs

Schedule C-7
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: 12 Months Actual
Type of Filing: Original
Work Paper Reference No(s).: None

Line No.	Description	Amount	Source
	(A)	(B)	(C)
1	Calendar Year 2007 Uncollectible Expense	$18,383,126	2007 FERC Form No. 1, page 322, line 162, col (b)
2			
3	Total 2007 Retail Revenue	$1,043,954,339	2007 FERC Form No. 1, page 300, line 10, col (b)
4			
5	Percentage of Uncollectible Expense	1.7609%	Line 1 / Line 3

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Deferred Case Expense

Schedule C-8
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Estimated
Type of Filing: Original
Work Paper Reference No(s).: None

Line No.	Description	Amount	Source
	(A)	(C)	(D)
1	Case Expense		
2	Attorney's Fees	$ 550,000	Estimate from FIC
3	Transcript Fees	$ 15,000	Estimate from FIC
4	Consultants/Expert Witnesses	$ 400,000	Consultant Estimates
5	Meeting and Hearing Expenses	$ 20,000	Internal Estimates
6	Printing Expenses	$ 8,000	Internal Estimates
7			
8	Total Applicable Rate Case Expenses	$ 993,000	Sum of Lines 2 through 6
9			
10	Carrying Costs adjusted for Fed Income Tax	9.36%	Schedule D-1, line 4 Col (E)
11			
12	Carrying Charge	$ 92,945	Line 8 x Line 10
13	Balance	$ 1,085,945	Line 8 + Line 12
14	First Year Collection-2009	$ 361,982	Line 13 / 3 years
15	Remaining Balance	$ 723,963	Line 13 - Line 14
16	Carrying Charge	$ 67,763	Line 15 x Line 10
17	Remaining Balance + Carrying Charge	$ 791,726	Line 15 + Line 16
18	Second Year Collection	$ 395,863	Line 17 / 2 Yrs. Remaining
19	Remaining Balance	$ 395,863	Line 17 - Line 18
20	Carrying Charge	$ 37,053	Line 19 x Line 10
21	Remaining Balance + Carrying Charge	$ 432,916	Line 19 + Line 20
22	Third Year Collection	$ 432,916	Line 21
23	Total Revenue Recovery	$ 1,190,760	Line 14 + Line 18 + Line 22

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Regulated Business Rate of Return Summary
As of June 30, 2008

Schedule D-1
Page 1 of 1
Witness Responsible:
Jeff D. Mackholm

Date of Capital Structure: June 30, 2008
Type of Filing: Original
Work Paper Reference No(s).:

Line No.	Class of Capital	Amount	% of Total	% of Cost	Weighted Cost %	Source
	(A)	(B)	(C)	(D)	(E = C * D)	(F)
1	Long-Term Debt	$759,404,859	34.35%	5.86%	2.01%	Schedule D-2, lines 25 and 29
2	Preferred Stock	$20,755,037	0.94%	4.18%	0.04%	Schedule D-3, lines 12 and 14
3	Common Equity	$1,430,469,308	64.71%	11.30%	7.31%	General Ledger Bal. & Exh. JDM -7
4	Total Capital	$2,210,629,204	100.00%		9.36%	Line 1 + Line 2 + Line 3

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Embedded Cost of Long-Term Debt
As of June 30, 2008

Schedule D-2
Page 1 of 1
Witness Responsible:
Jeff D. Mackholm

Date of Long-Term Debt: June 30, 2008
Type of Filing: Original
Work Paper Reference No(s).: WPD-2.1, WPD-2.2, WPD-2.3

Line No.	Debt Issue Type, Coupon, Rate	Date Issued (Mo/Day/Yr)	Maturity Date (Mo/Day/Yr)	Principle Amount	Face Amount Outstanding	Unamort (Discount) or Premium	Unamort Debt Expense	Unamort Gain or (Loss) On Reacquired Debt	Carrying Value	Annual Interest Cost**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I = E + F - G + H)	(J)
				$	$	$	$	$	$	$
1	First Mortgage Bonds:									
2										
3	FMB 10.70% SERIES	8-01-75	8-01-05	45,000,000	-	-	-	-	-	-
4	FMB 5.125% SERIES	9-30-03	09-30-13	470,000,000	470,000,000	(954,923)	2,320,824	-	466,724,253	24,711,452
5	FMB 6.35% SERIES *	4-15-77	4-15-07	25,000,000	-	-	-	-	-	-
6	FMB 12-1/8% SERIES	12-01-79	12-01-09	65,000,000	-	-	-	(379,590)	(379,590)	267,951
7	PCB 4.70 KY	8-17-05	1-01-28	35,275,000	35,275,000	-	624,697	-	34,650,303	1,689,961
8	PCB 4.80 OH AIR	8-17-05	1-01-34	137,800,000	137,800,000	-	2,191,158	-	135,608,842	6,700,328
9	PCB 4.80 OH H2O	8-17-05	1-01-34	41,300,000	41,300,000	-	791,948	-	40,508,052	2,013,457
10	FMB 16-3/4% SERIES	3-01-82	3-01-12	60,000,000	-	-	-	(1,285,980)	(1,285,980)	346,781
11	FMB 8.40% SERIES	12-01-92	12-01-22	225,000,000	-	-	-	-	-	-
12	FMB 6.40% SERIES A & B	9-29-92	8-15-27	60,100,000	-	-	-	-	-	-
13	FMB 6.50% SERIES	11-24-92	11-15-22	48,000,000	-	-	-	-	-	-
14	FMB 8.15% SERIES	1-14-93	1-15-26	226,000,000	-	-	-	(8,557,974)	(8,557,974)	487,866
15	FMB 7-7/8% SERIES	2-11-93	2-15-24	220,000,000	-	-	-	(7,800,211)	(7,800,211)	499,214
16	PCB 4.80 OH FGD	9-13-06	9-01-36	100,000,000	100,000,000	-	1,687,121	-	98,312,879	4,859,898
17	PCB Var OH AIR (held in trust 6/30/	11-15-07	11-01-40	-	-	-	49,035	-	(49,035)	49,854
18										
19	Other Long-Term Debt:									
20										
21	OAQDA 6.10% SERIES	9-01-95	9-01-30	110,000,000	-	-	-	-	-	-
22	Logicalis Capital Lease	12-31-04	12-31-07	612,061	-	-	-	-	-	-
23	VISTA Capital Lease	12-31-02	9-01-10	4,276,385	1,673,320	-	-	-	1,673,320	66,933
24										
25	TOTALS				786,048,320				759,404,859	41,693,695
26										
27	**EMBEDDED COST OF LONG-TERM DEBT**									5.490% ^1
28										
29	**REGULATED BUSINESS UNITS EMBEDDED COST OF LONG-TERM DEBT**									5.864% ^2
30										

31 ^1 Line 22 Column J / Column I
32 ^2 Excludes Pollution Control Bonds and Vista Capital Lease from calculation
33 * Sinking Fund Issue.
34 ** Annualized interest expense plus (or minus) amortization of discount or
35 premium plus amortization of issue costs minus (or plus) amortization
36 of gain (or loss) on reacquired debt.

THE DAYTON POWER AND LIGHT COMPANY
Case No. 08-1094-EL-SSO
BOOK II - Customer Conservation and Energy Management
Embedded Cost of Preferred Stock
As of June 30, 2008

Date of Preferred Stock: June 30, 2008
Type of Filing: Original
Work Paper Reference No(s).:

Witness Responsible:
Jeff D. Mackholm

Line No.	Dividend Rate Type, Par Value	Date Issued (Mo/Day/Yr)	Dollar Amounts Outstanding at Par Value	Premium or (Discount)	Issue Expense	Gain or (Loss) on Reacquired Stock*	Net Proceeds	Annual Dividends
	(A)	(B)	(C)	(D)	(E)	(F)	(G = C + D - E + F)	(H)
1	3.750% Series A $100 Par Value	6/01/47	9,328,000	-	-	-	9,328,000	349,800
2	3.750% Series B $100 Par Value	6/01/47	6,939,800	-	-	-	6,939,800	260,243
3	3.900% Series C $100 Par Value	6/01/50	6,583,000	-	-	-	6,583,000	256,737
4	7.480% Series D $100 Par Value	4/8/69	-	-	-	54,000	54,000	-
5	7.700% Series E $100 Par Value	3/23/71	-	-	-	(320,513)	(320,513)	-
6	7.375% Series F $100 Par Value	5/17/73	-	-	-	(365,970)	(365,970)	-
7	12.50% Series G $100 Par Value	10/30/74-4/30/75	-	-	-	-	-	-
8	8.625% Series H $100 Par Value	4/06/78-6/01/78	-	-	-	(247,775)	(247,775)	-
9	9.375% Series I $100 Par Value	5/16/79-8/08/79	-	-	-	(274,455)	(274,455)	-
10	11.60% Series J $100 Par Value	7/16/80	-	-	-	(941,050)	(941,050)	-
11								
12	TOTAL		22,850,800				20,755,037	866,780
13								
14	**DP&L EMBEDDED COST OF PREFERRED STOCK**							4.176% ^1
15								

16 ^1 Line 12 Column H/Column G
*Source - General ledger balances at June 30, 2008.

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Infrastructure Investment Rider (IIR) Rate Design

Schedule E-1
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: 12 Months Actual Customers, Forecasted Revenue Requirement
Type of Filing: Original
Work Paper Reference No(s).: None

Line		Residential [1]	Res. Elec.Heat	Secondary [2]	Sec. 3 Phase	Primary [3]	Primary Substation	High Voltage	Total	Source:
1	**Infrastructure Investment Rider**									
2	2007 Customers by Tariff	357,227	104,553	39,807	15,769	613	11	7	517,987	Datamart Internal Document
3	Customer Weighting Factors	1	1	4	4	4	30	30		Cost of service study case # 91-414-EL-AIR
4	Weighted number of Customers	357,227	104,553	159,228	63,076	2,452	330	210	687,076	line 2 x line 3
5	Percentage of Total Weighted Customers	51.99%	15.22%	23.17%	9.18%	0.36%	0.05%	0.03%		
6										
7	Total IIR Revenue Requirements								$355,233,725	Schedule A-2, Sum of line 29
8	Average Annual Rev Req								$50,747,675	line 7 / 7 years
9	Customer Related Component								56%	Infrastructure Invest. in AMI + Billing/Total II
10	Customer Related Rev Req								$ 28,635,449	line 8 x line 9
11	Cust Rev Req Assigned to Tariff	$ 14,888,244	$ 4,357,483	$ 6,636,188	$ 2,628,835	$ 102,193	$ 13,753	$ 8,752		line 10 x line 5
12	**IIR Charge Per Cust Per Month**	$3.47	$3.47	$13.89	$13.89	$13.89	$104.19	$104.19		line 11 / line 2 / 12 months
13										
14	Energy Related Component	2009	2010	2011	2012	2013	2014	2015	$ 22,112,226	line 8 - line 10
15	Avg. 7 Year kWh sales	11,014,698	14,823,083	14,747,753	14,682,692	14,571,960	14,482,766	14,417,238	14,102,884	WPA-1, line 3
16	**IIR Energy Rider $/kWh**								0.0015679	line 14 / line 15 / 1000
17										
18	Annual Recovery:									
19	Customer	$ 28,635,449	$ 28,635,449	$ 28,635,449	$ 28,635,449	$ 28,635,449	$ 28,635,449	$ 28,635,449		line 12 x line 2 x 12 months
20	Energy	$ 22,112,226	$ 22,112,226	$ 22,112,226	$ 22,112,226	$ 22,112,226	$ 22,112,226	$ 22,112,226		Avg II Energy Rider L16 * Annual Sales L15
21	Total Revenue Recovery	$ 50,747,675	$ 50,747,675	$ 50,747,675	$ 50,747,675	$ 50,747,675	$ 50,747,675	$ 50,747,675	$ 355,233,725	Total Cust+Energy Rev Recovery L19 + L20
22										
23										
24	Yearly Revenue Requirement	$ 13,543,223	$ 33,270,538	$ 47,151,422	$ 61,997,022	$ 63,491,036	$ 68,161,699	$ 67,618,786	$ 355,233,725	Schedule A-2, line 29
25										
26	Over (Under Recovery)	$ 37,204,452	$ 17,477,137	$ 3,596,253	$ (11,249,347)	$ (12,743,361)	$ (17,414,024)	$ (16,871,112)	$ 0	line 21 - line 24
27										
28	Carrying Cost on Over Recovery							Cumulative Balance	Carrying Charges	
29	2009	$ 37,204,452						$ 37,204,452	$ 3,482,337	line 29 x line 38
30	2010		$ 17,477,137					$ 54,681,590	$ 5,118,197	line 30 x line 38
31	2011			$ 3,596,253				$ 58,277,843	$ 5,454,806	line 31 x line 38
32	2012				$ (11,249,347)			$ 47,028,496	$ 4,401,867	line 32 x line 38
33	2013					$ (12,743,361)		$ 34,285,135	$ 3,209,089	line 33 x line 38
34	2014						$ (17,414,024)	$ 16,871,112	$ 1,579,136	line 34 x line 38
35	2015							$ 0	$ 0	line 35 x line 38
36	**Total Carrying Costs**								$ 23,245,431	Sum line 29 thru 35
37										
38	**Carrying Charge Rate**								9.36%	Schedule D-1, line 4
39		Residential [1]	Res. Elec.Heat	Secondary [2]	Sec. 3 Phase	Primary [3]	Primary Substation	High Voltage	Total	
40	**Adjusted Revenue Recovery**									
41	Total IIR Rev Req less Carrying Charges								$ 331,988,293	line 24 - line 36
42	Average Annual Rev Req								$ 47,426,899	line 41 / 7 years
43	Customer Related Component								56%	Infrastructure Invest. in AMI + Billing/Total II
44	Customer Related Rev Req								$ 26,761,631	Line 42 x Line 43
45	Cust Rev Req Assigned to Tariff	$ 13,909,389	$ 4,070,992	$ 6,199,879	$ 2,455,997	$ 95,474	$ 12,849	$ 8,177		(Line 44 - Streetlighting Recovery) x Line 5
46	**IIR Charge Per Cust Per Month**	$3.24	$3.24	$12.98	$12.98	$12.98	$97.34	$97.34		Line 45 / line 2 / 12 months
47										All others = Page 2, Line 3 * Residential
48	Energy Related Component								$ 20,665,269	Line 42 - Line 44
49	Avg. 7 Year kWh sales								14,102,884	Line 15
50	**IIR Energy Rider $/kWh**								0.0014653	Line 48 / Line 49 / 1000 (rounded to 7 decimals)
51		2009	2010	2011	2012	2013	2014	2015		
52	Annual II Revenue Recovery:									
53	Customer	$ 26,761,632	$ 26,761,632	$ 26,761,632	$ 26,761,632	$ 26,761,632	$ 26,761,632	$ 26,761,632		Sum (line 46 x Line 2 x 12 months) for all classes
54	Energy	$ 20,664,956	$ 20,664,956	$ 20,664,956	$ 20,664,956	$ 20,664,956	$ 20,664,956	$ 20,664,956		Avg II Energy Rider L50 * Annual Sales L49
55	**Total IIR Revenue Recovery**	47,426,588	47,426,588	47,426,588	47,426,588	47,426,588	47,426,588	47,426,588	331,986,115	Line 53 + Line 54
56										
57										
58	1 - Residential group includes 3,073 equivalent private outdoor lighting customers									
59	2 - Secondary group includes revenue recovery related to Streetlighting of				$ 8,873	(see WPA-2b)				
60	3 - Primary group includes 143 customers on School rate									

The Dayton Power and Light Company
Case No. 08-1094-EL-SSO
Book II - Customer Conservation and Energy Management
Energy Efficiency Rider (EER) Rate Design

Schedule E-2
Page 1 of 1
Witness Responsible:
Dona Seger-Lawson

Data: Forecasted
Type of Filing: Original
Workpaper Reference:

Line	Year	1	2	3	4	5	6	7	
		2009 ^1	2010	2011	2012	2013	2014	2015	Source:
1									
2									
3	Energy Efficiency Net Revenue Requirements	$ 13,006,224	$ 23,471,717	$ 33,742,626	$ 43,103,981	$ 54,903,703	$ 67,067,805	$ 77,365,431	Schedule A-3, line 27
4									
5	*Non-Shopping Sales Adjusted for EE (kWh)*	8,473,205,347	11,563,440,019	11,526,815,815	11,479,441,446	11,425,391,991	11,371,896,655	11,341,098,569	WPA-1, line 7
6									
7	Annual EE Rider ($ / kWh)	$ 0.0015350	$ 0.0020298	$ 0.0029273	$ 0.0037549	$ 0.0048054	$ 0.0058977	$ 0.0068217	Line 3 / Line 5 Rounded to 7 decimals
8									
9									
10									
11	Notes: ^1 2009 sales are reflective of April - December								
12									
13									

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

Schedule E-3
Tariffs

The Dayton Power & Light Company

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
INFRASTRUCTURE INVESTMENT RIDER (IIR)

The rates and charges listed in this tariff are to recover infrastructure investment costs related to the Customer Conservation and Energy Management programs. The infrastructure costs that are the basis of this rider are associated with Advanced Metering Infrastructure, Delivery System Automation, Billing System, and other implementation costs.

The IIR will be assessed based on two components 1) a customer charge component and 2) an energy charge component. The customer charge component will be assessed as stated below as such charge coincides with the Customer's Voltage Level of Service provided under this Schedule. The energy charge component will be consistent for all Voltage Level of Service Classes and will be assessed at a rate of $0.0014657 per kWh for all kWh.

RATE PER MONTH:

Residential	$3.24 per Customer
Residential Heating – Rate A	$3.24 per Customer
Residential Heating – Rate B	$3.24 per Customer
Secondary	$12.98 per Customer
Primary	$12.98 per Customer
Primary-Substation	$97.34 per Customer
High Voltage	$97.34 per Customer
Private Outdoor Lighting	$.39 per Customer
School	$12.98 per Customer
Street Lighting	$3.89 per bill rendered

The above charges are non-bypassable.

Filed pursuant to the Opinion and Order in Case No. 08-1094-EL-SSO dated _____, 2008 of the Public Utilities Commission of Ohio.

Issued _____, 2008 Effective _____, 2009

Issued by
PAUL M. BARBAS, President and Chief Executive Officer

THE DAYTON POWER AND LIGHT COMPANY
MacGregor Park
1065 Woodman Dr.
Dayton, Ohio 45432

P.U.C.O. No. 17
ELECTRIC DISTRIBUTION SERVICE
ENERGY EFFICIENCY RIDER (EER)

DESCRIPTION:

The Energy Efficiency Rider (EER) is intended to compensate the Dayton Power and Light Company for energy efficiency program costs and all compliance costs related to the energy efficiency standards prescribed by Section 4928.66 of the Ohio Revised Code.

APPLICABLE:

The EER will be assessed beginning April 1, 2009 on all Customers served under the Electric Distribution Service Tariff Sheets D17-D25 based on the following rate.

CHARGES:

Energy Charge (All kWh)	$0.0015350/ kWh

TERMS AND CONDITIONS:
This charge may be partially avoided by mercantile customers that meet the requirements specified in Ohio Administrative Code §4901:1-39-06 pursuant to a special arrangement agreed to by the customer and the Company.

OTHER

DP&L retains the right to adjust the EER annually with PUCO approval.

Filed pursuant to the Opinion and Order in Case No. 08-1094-EL-SSO dated _____, 2008 of the Public Utilities Commission of Ohio.

Issued _____, 2008 Effective _____, 2009

Issued by
PAUL M. BARBAS, President and Chief Executive Officer

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Residential
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of Demand (KW)	Level of Usage (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	0.0	50	$13.26	$12.35	($0.91)	-6.86%
2	0.0	100	$18.93	$17.12	($1.81)	-9.56%
3	0.0	200	$30.26	$26.52	($3.74)	-12.36%
4	0.0	400	$52.96	$45.56	($7.40)	-13.97%
5	0.0	500	$64.31	$55.11	($9.20)	-14.31%
6	0.0	750	$92.67	$78.80	($13.87)	-14.97%
7	0.0	1,000	$117.45	$101.29	($16.16)	-13.76%
8	0.0	1,200	$137.28	$117.83	($19.45)	-14.17%
9	0.0	1,400	$157.11	$134.52	($22.59)	-14.38%
10	0.0	1,500	$167.06	$142.85	($24.21)	-14.49%
11	0.0	2,000	$216.61	$184.28	($32.33)	-14.93%
12	0.0	2,500	$266.00	$225.81	($40.19)	-15.11%
13	0.0	3,000	$315.34	$267.06	($48.28)	-15.31%
14	0.0	4,000	$414.04	$349.67	($64.37)	-15.55%
15	0.0	5,000	$512.76	$432.30	($80.46)	-15.69%
16	0.0	7,500	$759.56	$638.91	($120.65)	-15.88%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Residential Heat (Summer)
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	0.0	50	$13.25	$12.33	($0.92)	-6.94%
2	0.0	100	$18.90	$17.10	($1.80)	-9.52%
3	0.0	200	$30.20	$26.47	($3.73)	-12.35%
4	0.0	400	$52.84	$45.46	($7.38)	-13.97%
5	0.0	500	$64.16	$54.98	($9.18)	-14.31%
6	0.0	750	$92.44	$78.61	($13.83)	-14.96%
7	0.0	1,000	$117.15	$101.04	($16.11)	-13.75%
8	0.0	1,200	$136.92	$117.53	($19.39)	-14.16%
9	0.0	1,400	$156.69	$134.17	($22.52)	-14.37%
10	0.0	1,500	$166.61	$142.47	($24.14)	-14.49%
11	0.0	2,000	$216.01	$183.78	($32.23)	-14.92%
12	0.0	2,500	$265.25	$225.18	($40.07)	-15.11%
13	0.0	3,000	$314.43	$266.30	($48.13)	-15.31%
14	0.0	4,000	$412.84	$348.66	($64.18)	-15.55%
15	0.0	5,000	$511.26	$431.05	($80.21)	-15.69%
16	0.0	7,500	$757.31	$637.03	($120.28)	-15.88%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Residential Heat (Winter)
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	0.0	50	$13.25	$12.33	($0.92)	-6.94%
2	0.0	100	$18.90	$17.10	($1.80)	-9.52%
3	0.0	200	$30.20	$26.47	($3.73)	-12.35%
4	0.0	400	$52.84	$45.46	($7.38)	-13.97%
5	0.0	500	$64.16	$54.98	($9.18)	-14.31%
6	0.0	750	$92.44	$78.61	($13.83)	-14.96%
7	0.0	1,000	$110.85	$98.84	($12.01)	-10.83%
8	0.0	1,200	$125.56	$111.13	($14.43)	-11.49%
9	0.0	1,400	$140.28	$123.51	($16.77)	-11.95%
10	0.0	1,500	$147.67	$129.68	($17.99)	-12.18%
11	0.0	2,000	$184.45	$160.46	($23.99)	-13.01%
12	0.0	2,500	$221.05	$191.25	($29.80)	-13.48%
13	0.0	3,000	$257.62	$221.83	($35.79)	-13.89%
14	0.0	4,000	$330.77	$283.04	($47.73)	-14.43%
15	0.0	5,000	$403.93	$344.28	($59.65)	-14.77%
16	0.0	7,500	$586.82	$497.40	($89.42)	-15.24%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Seconary Unmetered
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of Demand (KW)	Level of Usage (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	5	50	$25.04	$23.66	($1.38)	-5.51%
2	5	100	$30.34	$27.58	($2.76)	-9.10%
3	10	150	$35.63	$31.50	($4.13)	-11.59%
4	25	200	$40.90	$35.41	($5.49)	-13.42%
5	25	300	$51.47	$43.24	($8.23)	-15.99%
6	25	400	$62.03	$51.03	($11.00)	-17.73%
7	50	500	$72.64	$58.89	($13.75)	-18.93%
8	50	600	$83.19	$66.67	($16.52)	-19.86%
9	200	800	$104.33	$82.33	($22.00)	-21.09%
10	200	1,000	$125.47	$98.00	($27.47)	-21.89%
11	300	1,200	$146.61	$113.63	($32.98)	-22.50%
12	500	1,400	$178.34	$137.09	($41.25)	-23.13%
13	1,000	1,600	$182.74	$144.94	($37.80)	-20.69%
14	1,000	2,000	$200.31	$176.19	($24.12)	-12.04%
15	2,500	2,200	$209.00	$183.95	($25.05)	-11.99%
16	2,500	2,400	$217.68	$190.46	($27.22)	-12.50%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Seconary Single Phase
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	5	750	$101.06	$80.43	($20.63)	-20.41%
2	5	1,500	$180.34	$139.09	($41.25)	-22.87%
3	10	1,500	$256.70	$201.71	($54.99)	-21.42%
4	25	5,000	$638.14	$548.02	($90.12)	-14.12%
5	25	7,500	$746.77	$628.42	($118.35)	-15.85%
6	25	10,000	$855.43	$708.84	($146.59)	-17.14%
7	50	15,000	$1,454.54	$1,217.83	($236.71)	-16.27%
8	50	25,000	$1,883.51	$1,537.47	($346.04)	-18.37%
9	200	50,000	$5,246.88	$4,421.95	($824.93)	-15.72%
10	200	100,000	$7,391.77	$6,009.15	($1,382.62)	-18.70%
11	300	125,000	$9,991.49	$8,197.17	($1,794.32)	-17.96%
12	500	200,000	$15,862.05	$13,242.16	($2,619.89)	-16.52%
13	1,000	300,000	$27,253.06	$22,988.06	($4,265.00)	-15.65%
14	1,000	500,000	$34,762.37	$28,544.94	($6,217.43)	-17.89%
15	2,500	750,000	$67,058.13	$56,396.41	($10,661.72)	-15.90%
16	2,500	1,000,000	$76,393.07	$63,342.50	($13,050.57)	-17.08%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Secondary Three Phase
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	5	500	$81.98	$76.98	($5.00)	-6.10%
2	5	1,500	$187.68	$172.76	($14.92)	-7.95%
3	10	1,500	$264.05	$235.38	($28.67)	-10.86%
4	25	5,000	$645.49	$589.88	($55.61)	-8.62%
5	25	7,500	$754.12	$688.31	($65.81)	-8.73%
6	25	10,000	$862.78	$786.70	($76.08)	-8.82%
7	50	25,000	$1,890.86	$1,719.56	($171.30)	-9.06%
8	200	50,000	$5,254.23	$4,771.16	($483.07)	-9.19%
9	200	125,000	$8,471.56	$7,685.42	($786.14)	-9.28%
10	500	200,000	$15,869.39	$14,459.45	($1,409.94)	-8.88%
11	1,000	300,000	$27,260.41	$24,794.25	($2,466.16)	-9.05%
12	1,000	500,000	$34,769.72	$31,596.17	($3,173.55)	-9.13%
13	2,500	750,000	$67,065.48	$60,900.07	($6,165.41)	-9.19%
14	2,500	1,000,000	$76,400.41	$69,379.95	($7,020.46)	-9.19%
15	5,000	1,500,000	$133,200.75	$120,913.69	($12,287.06)	-9.22%
16	5,000	2,000,000	$151,819.21	$137,778.29	($14,040.92)	-9.25%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Primary Service
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	5	1,000	$222.68	$215.15	($7.53)	-3.38%
2	5	2,500	$277.49	$267.03	($10.46)	-3.77%
3	10	5,000	$445.86	$425.22	($20.64)	-4.63%
4	25	7,500	$769.85	$727.46	($42.39)	-5.51%
5	25	10,000	$860.42	$813.06	($47.36)	-5.50%
6	50	20,000	$1,608.96	$1,514.76	($94.20)	-5.85%
7	50	30,000	$1,965.65	$1,851.85	($113.80)	-5.79%
8	200	50,000	$5,013.20	$4,695.36	($317.84)	-6.34%
9	200	75,000	$5,904.94	$5,538.02	($366.92)	-6.21%
10	200	100,000	$6,796.66	$6,380.72	($415.94)	-6.12%
11	500	250,000	$16,815.43	$15,775.57	($1,039.86)	-6.18%
12	1,000	500,000	$33,513.30	$31,433.63	($2,079.67)	-6.21%
13	2,500	1,000,000	$74,638.04	$69,946.27	($4,691.77)	-6.29%
14	5,000	2,500,000	$166,580.38	$156,224.52	($10,355.86)	-6.22%
15	10,000	5,000,000	$332,785.35	$312,073.61	($20,711.74)	-6.22%
16	25,000	7,500,000	$654,602.73	$612,547.21	($42,055.52)	-6.42%
17	25,000	10,000,000	$743,001.50	$696,084.06	($46,917.44)	-6.31%
18	50,000	15,000,000	$1,308,830.05	$1,224,719.06	($84,110.99)	-6.43%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
School Rate
With Participation Vs. Without Participation

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Without Participation	With Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	0.0	1,000	$152.22	$146.69	($5.53)	-3.63%
2	0.0	2,500	$302.37	$288.69	($13.68)	-4.52%
3	0.0	5,000	$551.79	$524.35	($27.44)	-4.97%
4	0.0	10,000	$1,050.66	$995.79	($54.87)	-5.22%
5	0.0	15,000	$1,549.56	$1,467.23	($82.33)	-5.31%
6	0.0	25,000	$2,541.73	$2,405.30	($136.43)	-5.37%
7	0.0	50,000	$5,022.16	$4,749.32	($272.84)	-5.43%
8	0.0	75,000	$7,502.60	$7,093.30	($409.30)	-5.46%
9	0.0	100,000	$9,983.02	$9,437.35	($545.67)	-5.47%
10	0.0	150,000	$14,943.88	$14,125.35	($818.53)	-5.48%
11	0.0	200,000	$19,904.72	$18,813.34	($1,091.38)	-5.48%
12	0.0	250,000	$24,865.59	$23,501.37	($1,364.22)	-5.49%
13	0.0	300,000	$29,826.44	$28,189.39	($1,637.05)	-5.49%
14	0.0	350,000	$34,787.30	$32,877.40	($1,909.90)	-5.49%
15	0.0	400,000	$39,748.16	$37,565.38	($2,182.78)	-5.49%
16	0.0	450,000	$44,709.02	$42,253.40	($2,455.62)	-5.49%
17	0.0	500,000	$49,669.87	$46,941.42	($2,728.45)	-5.49%

The Dayton Power and Light Company
Case No: 08-1094-EL-SSO
Typical Bill Comparison
Residential
No Participation Vs. Current Rates (No Riders)

Data: 0 Months Actual, 12 Months Estimated
Type of Filing: Original
Work Paper Reference: None

Witness Responsible:
John B. Wagner, Jr.

Line No.	Level of (KW)	Level of (KWH)	Current Bill	Without Participation	Dollar Increase (Decrease)	Percent Increase
	(A)	(B)	(C)	(D)	(E = D - C)	(F = E/C)
1	0.0	50	$9.87	$13.26	3.39	34.35%
2	0.0	100	$15.39	$18.93	3.54	23.00%
3	0.0	200	$26.42	$30.26	3.84	14.53%
4	0.0	400	$48.52	$52.96	4.44	9.15%
5	0.0	500	$59.57	$64.31	4.74	7.96%
6	0.0	750	$87.18	$92.67	5.49	6.30%
7	0.0	1,000	$111.20	$117.45	6.25	5.62%
8	0.0	1,200	$130.43	$137.28	6.85	5.25%
9	0.0	1,400	$149.67	$157.11	7.44	4.97%
10	0.0	1,500	$159.31	$167.06	7.75	4.86%
11	0.0	2,000	$207.37	$216.61	9.24	4.46%
12	0.0	2,500	$255.25	$266.00	10.75	4.21%
13	0.0	3,000	$303.08	$315.34	12.26	4.05%
14	0.0	4,000	$398.79	$414.04	15.25	3.82%
15	0.0	5,000	$494.50	$512.76	18.26	3.69%
16	0.0	7,500	$733.81	$759.56	25.75	3.51%