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THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan	)))	Case No. 08-1094-EL-SSO
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs	)))	Case No. 08-1095-EL-ATA
In the Matter of the Application of The Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code § 4905.13	))))	Case No. 08-1096-EL-AAM
In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Amended Corporate Separation Plan	))))	Case No. 08-1097-EL-UNC

Comments of the Staff of the

Public Utilities Commission of Ohio

December 15, 2009

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Introduction

The application in this case has been bifurcated into two separate business cases – one for Advanced Metering Infrastructure (AMI) and one for Distribution Automation and Substation Automation, which is termed "Smart Grid" in the filing. We address each separately below.

The filing and the decision regarding deployment was originally driven by a time requirement, which derived from Dayton's application for federal funding pursuant to the American Recovery and Reinvestment Act. The staff appreciates the complexity and difficulty associated with responding to the staff's concerns and Article 4 of the stipulation in this case, and that they did so timely for the purpose of seeking federal funding.

The urgency of having to deploy systems on a timeline set by federal guidelines no longer exists. The release of time pressure is a significant factor in staff's consideration of how to proceed with the AMI portion of the filing.

Costing Methodology and Rates

DP&L developed a complex cost study to quantify its proposed and projected Infrastructure Investment (IIR) rates. These IIR rates are designed to recover the costs of both the AMI and Smart Grid deployments, and AMI dependent customer conservation and energy management programs.

A revenue requirement was calculated for each year, from 2010 through 2019, and rates were developed for each year. The 2010 and 2011 rates are proposed rates, which DP&L intends to implement on January 1, 2010 and January 1, 2011, respectively. Rates for the remaining eight years are projected and serve as an indicator of expected rates during that timeframe. Per the Stipulation, rates will be trued-up on a two-year basis.

Staff reviewed the costs and rates, and for the most part, found the company's approach to be reasonable. Staff was unable, however, to reconcile the depreciation accrual rates used in the study with the most recently approved rates. Accordingly, Staff recommends the study be revised to reflect the most recently approved rates. Since electronic meters are a new account classification, Staff will accept the proposed fifteen year life, subject to ongoing review. Other assumptions within the study are addressed in both the Advanced Metering Infrastructure and the Smart Grid Sections of these comments.

With respect to rate development, Staff notes that the Stipulation required the company to develop independent business cases for both its AMI and Smart Grid proposals. Inasmuch as each of these programs may take different paths in terms of approval, implementation, and cost recovery, Staff recommends the company recover the costs of each in separate rate mechanisms. This will facilitate separate accounting of both costs

and benefits for AMI on the one hand, and Smart Grid on the other, should the two programs proceed on separate bases and schedules.

The company proposed a bifurcated rate, with 43% of total costs being recovered through a customer charge, and 57% of costs being recovered through an energy charge. Staff does not believe there are any IIR costs that vary with energy usage. Accordingly, Staff recommends that 100% of the IIR revenue requirement be recovered through fixed customer charges.

Advanced Metering Infrastructure

The first objective of the staff of the Commission is to assess the value proposition for customers resulting from the deployment of advanced metering infrastructure and related systems. That value proposition must enable customers to manage their electricity costs by receiving and responding to time differentiated price signals in such a manner as to be able to recoup their costs for the investment in infrastructure.

The decision of whether to recommend approval of the proposal turns on the business case. Therein, the costs of deployment are generally front loaded over the 18 year evaluation period and the operational benefits are back loaded.

If it appears there is value to customers from deployment, staff would support recovery of costs net of operational benefits to the company. Operational benefits consist of cost reductions to company operations and revenue enhancements the company will realize as a result of deploying AMI / Smart Grid.

A key parameter is the net present value of costs net of operational benefits on a per-customer basis. Quantifying that value enables the staff and stakeholders to make a judgment about whether customers have a reasonable opportunity to recoup those costs by adjusting their consumption patterns so as to manage and lower their bills.

In these comments staff identifies certain issues that appear to impact the business case for AMI or the ability to definitively quantify costs and benefits associated therewith, and therefore impede the quality of staff's assessment. We recommend that such issues be addressed in the context of stakeholder discussions. Their resolution will enable us to make a proper assessment. In addition, staff makes specific recommendations regarding part of the company's proposal, which we believe will enable progress on a critical plan element while allowing for resolution of the business case issues.

Capacity Price Projections

Company witness Teresa F. Marrinan is responsible for valuing the avoided capacity. "DP&L acquired projected capacity prices from a third party consultant. The consultant, Charles River Associates, used its market knowledge and models to project the rate at which capacity prices will increase until they reach the fundamental price level of the cost of new generation."[1]

Figure 1 below is taken from the direct testimony of Scott W. Niemann of Charles River Associates. Ms. Marrinan's valuation[2] approximately tracks the values in Figure 1. They are interpolated to accommodate the need for annual values however the trend line of values used to calculate the value of avoided capacity tracks the graphed values. For example, the calculations of benefits associated with AMI dependent CCEM programs and 3rd party curtailment made by witness Kevin Hall are based upon the valuation data adopted by Ms. Marrinan and represented in Figure 1.[3]

The "actual vs. projected" cutoff line was arguably properly drawn for the original filing of this case. On August 4, 2009 the filing was revised however the chart was not updated to account for more recent information. In the interim another Base Residual Auction (BRA) was held by PJM.

"The 2012/13 Reliability Pricing Model (RPM) Base Residual Auction cleared 136,143.5 MW of unforced capacity in the RTO at a Resource Clearing Price of $16.46/MW-day. … The $16.46/MW-day RTO resource clearing price represents a decrease of $93.54/MW-day from the 2011/2012 BRA. The RPM auction price was lower because of a growth in the available capacity and a decline in demand."[4]

The company's valuation of 2012/2013 capacity exceeds the actual by a factor of almost 10. Due to the severity of price decline in 2011/2012 and given the apparent ongoing supply and demand balance in PJM, subsequent years' projections are also suspect. The results of the 2011/2012 BRA were known at the time of the revised filings in this case, and the prices used to value capacity should have been also revised.

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[1] Direct Testimony of Teresa F. Marrinan at p. 3.

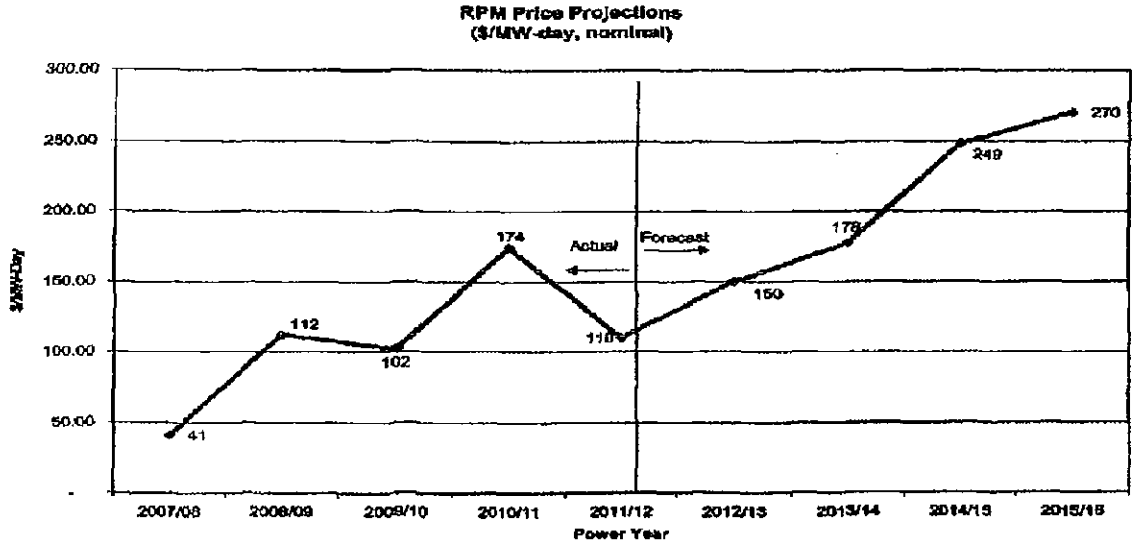
[2] See workpaper WPF-1 in DP&L's original combined ESP and CCEM filing.

[3] See Work Paper WPH-1.10, line No. 36 and other lines.

[4] 2012/2013 RPM Base Residual Auction Results, PJM Document #540109 at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx

These inflated capacity values tend to overstate customer benefits associated with demand reduction. Staff believes the revisions will reduce the value of programs by reducing the value of avoided capacity. We recommend the company revise its estimates and recalculate the benefits accordingly.

Figure 1: Projected RPM Market Clearing Prices



Energy Price Projections

Dayton used several energy prices to value benefits, however, they all were based upon the company's forward curve as that curve was established on July 2, 2008.[5] The revised filing for AMI and Smart Grid was made on August 4, 2009. Dayton could have reasonably updated its forward curve to reflect market conditions a year later than the forward curve they used.

During the next year after Dayton established its forward curve the market for electric energy tanked. Staff compared the on and off peak forward prices used to value energy in calculating benefits in this case with forward prices as of July 2, 2009 published for the AD Hub by the Intercontinental Exchange (ICE).[6] The simple average of the ICE on peak prices for forward months from August 2009 through July 2012 (the months in common between the two forward curves) was 36% lower than the prices comprising the Dayton forward curve. Similarly, the comparison of average off-peak prices showed that

[5] Response to Staff Data Requst #19, December 14, 2009.

[6] ICE forward energy quotes based upon daily email publication received by staff on July 2, 2009.

the July 2009 ICE forwards were 24% lower than the prices comprising the Dayton forward curve.

Dayton should have updated its forward curve in order to reflect the market conditions as they were known at the time the filing was updated. Failing to have done so has resulted in a significant overvaluation of avoided energy benefits. We therefore recommend the business case be updated to reflect currently projected energy prices.

Program Participation Rates

The company projects the following program participation rates for the year 2019:

Residential	% of Customers
Direct Load Control (opt-in)	8.13%
Time of Use (opt-in)	8.70%
Peak Time Rebate (opt-out)	12.44%
Non-Residential	
Direct Load Control (opt-in)	8.87%
Time of Use (opt-in)	9.04%
Peak Time Rebate (opt-out)	9.04%

The participation rates were derived from surveys of customers. The staff has no confidence the surveys have any predictive value whatsoever. No value proposition was presented to survey respondents in terms of potential levels of cost savings they might achieve on bills. Similarly, no context was provided to respondents in terms of what it might cost them to participate in the programs either in dollar terms or in terms of effort or inconvenience in order to achieve a level of savings. Survey respondents based their preferences on an abstraction when actual value drives their behavior in reality.

Given the response rates they did get, Dayton made a judgment that 20% of respondents who expressed moderate or strong interest in the programs (even though no value proposition was provided) would actually participate in the programs. Dayton assumed that the rate of enrollment of the 20% would be equally year by year through 2019. That judgment, despite the claim that it is derived from experience, appears to staff to be arbitrary.

We recommend that the company work with staff and stakeholders to develop the specifics of a value proposition for customers of each of the programs based upon near term energy and capacity valuations, and conduct further consumer research based upon those specifics. We then recommend the company revise or update participation estimates.

Levels of Demand Reduction

Demand reduction levels on a per-customer basis are a function of rate differentials. Put differently, the more money customers can save per kilowatt hour (at any given moment or during any given hour) the more they will reduce their consumption.

Rate differentials for TOU and PTR have not been established. It is therefore speculative to estimate how much customers will response to prices and price differentials. This calls into question the levels of demand reduction and energy savings the company has attributed to the rate programs. We therefore recommend the company work with staff and stakeholders to design rates based upon further research and information, and then estimate customer response when the rate differentials are known.

Momentary Interruption Data

The Commission in its Finding and Order and Entry on Rehearing in Case No. 06-653-EL-ORD7 (06-653 Case) directed Staff to continue to monitor the ability of electric utilities to accurately measure and report the momentary average interruption frequency index (MAIFI)[8] and to make recommendations with respect to momentary interruptions and their impact on customers. MAIFI can be used to measure momentary interruption frequency for each distribution circuit and across an electric utility's distribution system. In its Finding and Order the Commission declined to require the electric utilities "to take steps necessary to manually gather MAIFI information throughout its system and report it,"[9] but noted its awareness that "as technology is deployed throughout the electric distribution systems, this information will become more accurate and widely available."[10] In its Entry on Rehearing, the Commission further stated that "it would be imprudent for the electric utilities to make investments to improve MAIFI accuracy without taking the

[7] Entry on Rehearing, page 10, and Finding and Order, page 14 in Case No. 06-653-EL-ORD, *In the Matter of the Commission's Review of Chapters 4901:1-9, 4901:1-10, 4901:1-21, 4901:1-22, 4901:1-23, 4901:1-24, and 4901:1-25 of the Ohio Administrative Code.*

[8] MAIFI = the total number of customer momentary interruptions divided by the total number of customers served.

[9] Finding and Order in Case No. 06-653-EL-ORD, page 14.

[10] Ibid.

time to consider integrating such improvements with other potential programs such as an automated metering infrastructure and/or distribution automation".[11]

In response to this Commission directive, Staff inquired of DPL the extent to which the company will use its new smart meter technology to compile momentary interruption data from smart meters to compute MAIFI performance at the circuit and distribution levels. Based on data request responses,[12] Staff understands that DPL will be able to use its new technology to compile momentary interruption data from smart meters. Staff expects DP&L to utilize this ability and proceed with the accumulation of customer-specific momentary interruption information in a database suitable for future analysis.

Billing System

Witness Karen R. Garrison recites a key finding from Case No. 03-2441-EL-ATA et. al.: "...as part of an audit by the PUCO, in December, 2004, UtiliPoint stated, 'Although UtiliPoint International has determined that the decision to modify the existing billing system and the associated expenditures for those modifications were prudent in the late 1990's, it is strongly recommended that DP&L undertake a proactive look at market alternatives in 2005 for more efficient ways to perform the billing function.' The system described above meets this need."[13]

Although a new billing system is necessary to support AMI and related programs, the need for a new billing system precedes and goes beyond support for the AMI dependent programs, as the recommendation in Case No. 03-2441-EL-ATA et. al. indicates. We recommend the Company immediately commence implementing a new billing system fully capable of handling time differentiated rates and other capabilities as may be needed to exploit the full value of an AMI deployment and related programs, and other billing requirements.

In addition, the staff recommends that those billing system costs that were included in the AMI business case should be removed from the cost side of the business case analysis. Because we believe the need for a new billing system is independent of AMI, it should not be recovered through the IIR. Dayton should seek recovery of costs associated with billing system implementation through a distribution rate case or through another mechanism as may be appropriate.

[11] Entry on Rehearing, page 10
[12] See DPL's response to Staff Data Requests 12 and its supplemental response to Staff Data Request 9
[13] Direct Testimony of Karen R. Garrison, p. 28 of 41.

AMI Operational Benefits

According to the Company's response to the Staff's data request on November 24, 2009, the Company states that operational benefits for the years 2020-2027 are not recognized in the rate design for the period 2010 – 2019, but they will be recognized later. These operational benefits, which are substantial, should be recognized in rates as pursuant to the business case in order for this sizeable investment to have value to customers. This is the Staff's quid pro quo for recommending AMI to go forward. If there are any sizeable deviations from the business case (i.e. a reduction in 10% of the expected operational cost savings or an increase in implementation costs due to unforeseen circumstances, the Commission should be notified immediately to determine if the AMI investment should continue to proceed forward or if there is an alternative path. Should the Commission approve staff's recommendation of further revisiting the business case, staff reserves the right to more closely examine the level of operational benefits stated therein.

IIR Shared Savings

Company witness Ms. Dona Seger-Lawson has provided for a shared savings stream to be paid to the Company for its investment in AMI (see Schedule C-5 page 1 of 1). As stated previously in Staff comments, much of the consumer benefit related to demand response may not materialize due to changing market conditions. Such AMI enabled customer energy/demand savings benefits are provided in Scott Kelly's WPHI-1 Business Cases Summary on line 5. Due the substantial amount of "soft benefits" reliant on customer's future response to prices and those risks directly borne by its customers, the Staff does not recommend any shared savings in this case.

Overall Recommendations on AMI

Staff cannot recommend moving ahead with a full AMI implementation at this time. The issues associated with both the estimation and valuation of benefits in the business case, are of sufficient gravity that staff believes they should be completely and systematically revisited.

However, we do recommend moving ahead with implementing the new billing system because the need for one exists independent of AMI. Implementing a fully capable billing system now will enable customers to take advantage of the advanced metering capability if and when it becomes available, assuming the revised business case is acceptable.

Smart Grid Section

Smart Grid Plan

DPL's smart grid vision includes a fully network-connected system that identifies and communicates grid status and automates transmission and distribution decision-making systems to enable more efficient and reliable delivery of energy through real-time and secure automated controls.[14] DPL now plans to implement such a system over an accelerated 10-year period 2010 through 2019. The plan entails the automation of all DPL's substations and circuits. For substations, that involves upgrading relay protection and communication systems to enable fault isolation and load redistribution. For circuits, it involves installation of a series of controls, switches, and monitors as well as supporting communications infrastructure. DPL's overall automation schedule is listed by year in the following table.

Schedule for Substation and Circuit Automation[15]

Year	Number of Substations	Number of Circuits
2010	8	8
2011	13	54
2012	15	48
2013	13	53
2014	14	48
2015	13	57
2016	13	47
2017	13	47
2018	13	32
2019	12	53
Total	**127**	**447**

[14] Book II – Customer Conservation and Energy Management Programs, Chapter 4, page 1, filed on October 10, 2008

[15] See DPL response to Staff Data Request 9

Plan Requirements

DPL's distribution automation (DA) plan requires automatic reclosers, capacitor banks, air break switch controls, single-phase sensors, voltage regulator controls, pad-mounted switch gear, new poles, distribution SCADA support, two-way voice/data communication to DA devices, DPL engineering and project management, and outsourced engineering. In addition, its substation automation (SA) plan requires new relays, upgraded pilot wire, communication gateways, SCADA[16] communication upgrades two-way voice radios, and will also require DPL engineering and project management, and outsourced engineering resources.[17]

Staff's Investigation of Costs

One of Staff's objectives was to assess whether DPL's cost estimates were sufficiently accurate to use as the basis for setting the initial dollar amount for Rider IRR. To begin that assessment, Staff requested copies of DPL's recent (2007-2008) work orders for each type of the major equipment components required for smart grid, and compared those costs against those included in the applicable working papers supporting DPL's revised business case. Based on those comparisons, staff noted that the costs reflected in the historical work orders are similar to those reflected in the working papers. For new equipment components, where no prior work orders existed, Staff reviewed DPL's detailed estimates or other methods (e.g., use of vendor information and work orders for similar equipment) and considers them reasonable.

Another of Staff objectives was to determine the extent to which DPL's proposed Smart Grid program included capital investments that replaced or duplicated those already being made under its current maintenance and capital improvement program. For example, DPL has been capturing GPS data during their pole inspection process. Through data requests, Staff asked if DPL was using the collected GPS data from 2006 to present to help create the Geographical Information System (GIS). In response, DPL indicated that data collected from 2006 to present will be utilized in creating and completing its GIS.[18]

DPL has been installing new capacitors and capacitor controls, replacing remote terminal units (RTU's), and replacing obsolete relays with digital relays for the years 2005-2008 as a part of its facilities and equipment investment plan. With the installation and replacement of the above components already taking place prior to implementation of DA

[16] SCADA = Supervisory Control and Data Acquisition
[17] Book II – Customer Conservation and Energy Management Programs, Chapter 4, pages 4 through 9, filed on October 10, 2008
[18] DPL Data Request I 1, Question and response 1

and SA, Staff sought to clarify whether the projected expenditures for these capital projects would now cease or be modified, and either be wholly or partially recovered as part of the Infrastructure Investment Rider (IIR).

Staff determined that the only capital expenditure item described above that will cease is the "RTU Installation Program." These expenditures will cease beginning in 2011. According to the Company, projected expenditures for replacing RTUs will be modified in future Rule 4901:1-10-26 filings. RTU replacements required to provide smart grid functionality will be done under the IRR. RTU replacements because of failure or other operational issues will continue to be funded outside of the IIR.

Capacitor installations are not part of the Distribution Automation (DA) project. The capacitor controls, however, are part of the project, and the new controls will have a communications modem and will require the installation of additional sensors on the existing capacitor. Digital relays, as part of SA, will replace existing relays on the distribution circuits.[19]

The specific substation/circuits that are scheduled to have the RTUs and capacitors and controls replaced are not yet identified. These replacements will be determined according to the budgeted capital expenditures in the annual report required by Rule 4901:1-10-26.

Staff's investigation of DP&L Smart Grid cost estimates also included an analysis of DA and SA related Operation and Maintenance (O&M) expenses. Staff first examined the basis for the Company's estimate of Distribution Automation Maintenance Costs as a percent of Cumulative Capital Investment. According to the Company, Operation & Maintenance costs on hardware equipment are historically between 3-5% of capital cost. Looking at the DA capital costs and incrementally new equipment DPL estimated rate of 1.8% O&M cost on the total DA capital costs to cover the increase.

The Company asserts that maintenance activities on the new equipment are expected to include: routine maintenance on the controls of all the devices; battery replacement; communications modem replacement; FCC required checks and maintenance on the 18 additional radio tower sites; and required antenna adjustments. In addition, the equipment installed will be able to self-diagnose problems and initiate alarms when there is trouble, and technicians will need to respond to these alarms. This is particularly critical for capacitor controls that trigger such alarms, as they must be repaired in a timely fashion to control the circuit to a unity power factor in order to reduce losses.[20]

[19] DPL Data Request 11, Question and response 2, 2a, and 2b

[20] DPL Data Request 11, Question and response 3a

The O&M costs for Substation Automation are based on 5% of the capital costs for the new communications equipment to be installed at the substations. The maintenance costs for the relay replacements are already accounted for on the current equipment. So this percentage represents only the incremental increase in the maintenance of the automation equipment. With the addition of the new broadband communications equipment in all the distribution substations, the maintenance activities required by Substation Automation will include the annual FCC checks and maintenance, antenna adjustments as needed, gateway or RTU battery replacements, RTU repairs, and responding to self diagnoses alarms for the new equipment.21 Overall, Staff considers DPL's operation and maintenance cost estimates to be reasonable.

Staff's Investigation of DA/SA Project Scope & Design Criteria

Staff began its analysis by examining the basis for the "Smart Grid Corridor." While it appears most of the substations selected for automation in years 2010-2012 are located in the "DPL Smart Grid Corridor," Staff asked the Company to provide the criteria used for selecting the substations outside the corridor.[22] According to the Company, there are substations presently outside the corridor which have monitoring capability only and do not have breaker control. The inclusion of some of these substations during the initial two years of the program will permit those distribution substations to have supervisory control for their distribution circuits, which will assist in faster circuit restoration. Staff finds DPL's rationale for selecting substations outside the "Smart Grid Corridor" reasonable.

Staff also asked the Company to provide the criteria used to select the circuits for automation for years 2010-2012.[23] According to the Company, the criteria were based on the following objectives:

- Capture as many circuits in the corridor as possible;
- Select poorer performing circuits early in implementation;
- Ensure the ability to tie the circuit to adjacent circuits;
- Select a solid cross-section of circuits across the service territory; and
- Ensure that SCADA is installed at the substations.

[21] DPL Data Request 11, Question and response 4 and 4a

[22] DPL Data Request 9, Question and response 1

[23] DPL Data Request 9, Question and response 4

The Company asserts that SCADA is a subset of substation automation and is a requirement for completing circuit automation. Staff considers DPL's criteria for selecting circuits for automation to be reasonable

Staff next investigated some of the Company's design criteria for circuit automation, which appears in the table below:[24]

Equipment	Quantity Per Circuit
Underground reclosers	2
Overhead reclosers	2
Air brake switch controls	4
Voltage regulator controls	1
Pad mounted switchgear	0.5

Staff determined that DPL made the assumption to split each distribution circuit into three sections for circuit automation. With this assumption, it was decided that each circuit would include one to two reclosers with the tie between circuits being a recloser. This is the criteria the Company used for the two reclosers on average for overhead and underground circuits. The quantities for air brake switch controls, capacitor bank controls and voltage regulator controls are averages based on the total number of these units divided by the total number of circuits to be automated. The pad mounted switchgear average is based on the total number of devices divided by the total circuits to be automated. DPL developed the estimates based on these averages. According to DPL, these assumptions may be adjusted as the Company continues to refine the circuit automation plan, deploy the field equipment, and gain experience in the operation of this equipment. Staff finds DPL's assumptions and methodology reasonable.

Staff also investigated when a pole replacement is needed as a result of DA implementation and the criteria used to determine the estimated number of pole replacements per year.[25] A new pole will be needed if the existing pole cannot support the new or relocated device, or if the location of the pole is no longer appropriate. The estimated new-pole costs are based on the assumption that 10% of the devices will require a new pole. Staff considers DPL assumption to be reasonable.

[24] DPL Data Request 9, Question and response 5
[25] DPL Data Request 9, Question and response 6

Staff's Investigation of DA/SA Benefits

Based on the Company's filings, DPL's reliability will improve with the deployment of DA and SA, including a 20% average reduction in Customer Minutes Interrupted (CMI) and a 32% reduction in customers experiencing sustained outages. In response to further inquiry from staff regarding the CAIDI[26] and SAIFI[27] impact of SmartGrid, the company provided the following projections assuming that SmartGrid is approved according to the Company's application:

Year	Projected CAIDI Impact	Projected SAIFI Impact
2010	0.00	0.00
2011	0.37	-0.01
2012	2.07	-0.04
2013	4.15	-0.08
2014	5.96	-0.11
2015	8.49	-0.15
2016	11.19	-0.19
2017	12.84	-0.21
2018	14.65	-0.23
2019	16.26	-0.25
2020	18.22	-0.27

DPL reviewed circuit outage history and made reasonable assumptions regarding the restoration processes that would occur with its smart grid deployment. This provides the background for how the expected reliability improvements were calculated. The Company asserts that the benefit of smart grid deployment will be to reduce the overall outage time for customers as well as to facilitate a reduction in the number of customers experiencing sustained outages. Staff agrees that DA and SA implementation provides the remote sensing and remote control capabilities such that outages on distribution circuits can be remotely and/or automatically shortened.

Staff agrees with the Company that implementation of DA and SA provides the remote sensing and remote control such that outages on distribution circuits can be remotely and/or automatically shortened. Staff also recognizes that implementation of DA and SA does not prevent certain outages from occurring and in some outage cases their CAIDI will actually increase. In any event, Staff also recognizes that CAIDI will increase as a numerical metric simply due to the formula which is used to calculate CAIDI. Staff understands that an increase to CAIDI resulting from the deployment of DA does not equate to customers being without service for longer periods of time.

Staff accepts the Company's projected reliability performance impacts and recommends that if the Commission approves the Smart Grid portion of DP&L's Revised Business Cases, Staff would expect the Company to reflect its projected SAIFI and CAIDI impacts, as presented in the table above, as incremental adjustments to its reliability performance standards as required by Rule 4901:1-10-10 of the Ohio Administrative Code.

Smart Grid Bill Impact

Although DPL provided Staff an estimated bill impact for its proposed Smart Grid program (without AMI), it did not provide staff with the fixed-charge rate which staff believes is the correct rate design for the DA associated plant. As a result, Staff is unable to make a proper evaluation of the Smart Grid program's bill impact, and therefore cannot support the Smart Grid component at this time.

Smart Grid Benefits Valuation

The benefits in Dayton's Smart Grid business case are based at least in part upon valuations of capacity and energy avoided. Those valuations are subject to the same issues that apply to the AMI business case. The value of capacity and energy were not updated to reflect current market conditions. Benefits are therefore overstated.

Smart Grid Recommendations

Based upon the inability to evaluate the impact of the Smart Grid upon customer bills, and based upon the valuation of capacity and energy benefits using stale market data, staff cannot support the Smart Grid component at this time. We recommend the company systematically revisit the Smart Grid business case, and provide bill impacts based upon costs net of operational benefits per the revised business case.

Summary of Recommendations

The company's cost study should be revised to reflect the most recently approved depreciation rates.

The company should not receive any shared savings from programs in this filing.

There should be two separate rates, one for AMI and another for Smart Grid.

Any rate for AMI or Smart Grid deployment should recognize costs net of operational benefits to the company for the full term of the business case.

The business cases for AMI and Smart Grid should be systematically reviewed and revised in a stakeholder context in order to address issues associated with customer program participation rates and benefits valuation.

Costs for both AMI and Smart Grid should be recovered in respective rates by means of a fixed customer charge. The Company should provide an analysis of customer bill impacts for the revised business cases.

Staff would support a separate application for approval to move forward with implementing a billing system capable of handling time differentiated rates and other needs.

Respectfully submitted,

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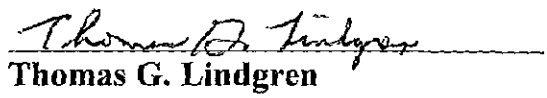
CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been served via electronic mail upon the following counsel of record, this 15th day of December, 2009.

Respectfully submitted,



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