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Case Number: 12-426-EL-SSO
12-427-EL-ATA
12-428-EL-AAM
12-429-EL-WVR
12-672-EL-RDR

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Description of Document: Revised Electric Security Plan
Book III
Testimony and Appendices

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
ROE Ratios of Comparable Firms

Data: Historical and Forecasted
Type of Filing: Second Revised
Work Paper Reference No(s).: Second Revised WJC-12.C

Second Revised WJC-12.A
Page 1 of 1
Witness Responsible: William J. Chambers

	Credit Rating			ROE					
				Actual			Projected		
Company Name	Fitch	S&P	Moodys	2009	2010	2011	2012	2013	2015-2017
Florida Power Corporation	BBB+	BBB+	Baa1	11.7%	9.7%	6.6%			
Ohio Power Company	BBB+	BBB	Baa1	20.4%	13.7%	10.2%	10.0%	9.5%	9.5%
Pacific Gas & Electric Company	BBB+	BBB	A3	12.2%	10.0%	7.2%	7.5%	9.0%	10.5%
Public Service Co. of Colorado	BBB+	A-	Baa1	8.8%	10.1%	9.4%			
South Carolina Electric & Gas Company	BBB+	BBB+	Baa2	9.6%	8.8%	8.6%			
Tampa Electric Company	BBB+	BBB+	A3	9.2%	11.4%	10.9%			
Union Electric Company	BBB+	BBB-	Baa2	7.2%	9.2%	7.2%			
Virginia Electric and Power Company	BBB+	A-	A3	5.3%	10.9%	9.5%			
Black Hills Power Inc.	BBB	BBB-	Baa2	8.7%	10.6%	8.4%			
The Detroit Edison Company	BBB	BBB+	Baa1	10.1%	11.2%	10.7%			
Monongahela Power Company	BBB	BBB-	Baa1	-	17.4%	0.2%			
NorthWestern Corporation	BBB	BBB	Baa1	9.5%	9.6%	11.0%	9.5%	9.5%	10.0%
PacifiCorp	BBB	A-	Baa1	8.6%	8.2%	7.6%			
Public Service Company of Oklahoma	BBB	BBB	Baa1	9.7%	8.8%	14.4%			
Public Service Company of New Hampshire	BBB	A-	Baa2	9.6%	10.9%	10.0%			
Southwestern Public Service Company	BBB	A-	Baa1	7.2%	8.2%	8.8%			
Westar Energy, Inc.	BBB	BBB	Baa2	7.9%	8.8%	8.9%	8.5%	8.0%	8.5%
Appalachian Power Company	BBB-	BBB	Baa2	6.1%	4.9%	5.7%			
Arizona Public Service Company	BBB-	BBB	Baa1	7.4%	9.2%	8.7%	9.0%	9.5%	9.0%
Consumers Energy Company	BBB-	BBB-	Baa2	7.8%	10.9%	11.0%	13.0%	13.0%	12.5%
Empire District Electric Company	BBB-	BBB-	Baa2	7.3%	7.5%	8.1%	7.5%	8.0%	9.0%
Indiana Michigan Power Company	BBB-	BBB	Baa2	13.9%	7.5%	8.7%			
Indianapolis Power & Light Company	BBB-	BBB-	Baa2	15.0%	15.8%	13.7%			
Kentucky Power Company	BBB-	BBB	Baa2	5.8%	8.0%	9.3%			
Southwestern Electric Power Company	BBB-	BBB	Baa3	8.2%	8.9%	9.3%			
Nevada Power Company	BB+	BB+	Baa3	5.1%	6.9%	4.7%	8.0%	8.0%	9.0%
Sierra Pacific Power Company	BB+	BB+	Baa3	7.7%	7.3%	6.1%			
Tucson Electric Power Company	BB+	BB+	Baa3	14.8%	16.0%	11.1%	10.0%	11.0%	14.0%
			Minimum:	5.1%	4.9%	0.2%	7.5%	8.0%	8.5%
			25th Percentile:	7.4%	8.2%	7.5%	8.0%	8.0%	9.0%
			Median:	8.7%	9.4%	8.9%	9.0%	9.5%	9.5%
			Average:	9.4%	10.0%	8.8%	9.2%	9.5%	10.2%
			75th Percentile:	9.9%	10.9%	10.3%	10.0%	9.5%	10.5%
			Maximum:	20.4%	17.4%	14.4%	13.0%	13.0%	14.0%
The Dayton Power and Light Company	BBB-	BBB-	Baa2	18.0%	20.0%	14.1%			

Notes & Sources:
Credit ratings from Second Revised WJC-12.C.
ROE = Net Income / ((Book Equity $year_t$ + Book Equity $year_{t-1}$) / 2) from WJC-12.C.
Projections from ValueLine. ROE = Return on Common Equity.
Companies without projections are not substanial subsidiaries of their parent company. A subsidiary company must make up at least 2/3 of the parent company's 2011 operating revenue to be considered substantial.
Projections for Ohio Power Company are from the parent company AEP, which also owns Public Service Company of Oklahoma, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Southwestern Electric Power Company.
The Projection for 2015-2017 is for each year 2015, 2016, 2017 separately, it is not a sum.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
ROE By Credit Rating

Data: Historical
Type of Filing: Second Revised
Work Paper Reference No(s).: Second Revised WJC-12.A

Witness Responsible: William J. Chambers

Fitch

	25th Percentile ROE				75th Percentile ROE			
Credit Rating	2009	2010	2011	Average	2009	2010	2011	Average
BBB+	8.4%	9.5%	7.2%	8.4%	11.8%	11.0%	9.7%	10.8%
BBB	8.5%	8.8%	8.4%	8.5%	9.6%	10.9%	10.7%	10.4%
BBB-	7.0%	7.5%	8.5%	7.7%	9.7%	9.7%	9.8%	9.7%
BB+	6.4%	7.1%	5.4%	6.3%	11.3%	11.7%	8.6%	10.5%

S&P

	25th Percentile ROE				75th Percentile ROE			
Credit Rating	2009	2010	2011	Average	2009	2010	2011	Average
A-	7.2%	8.2%	8.8%	8.1%	8.8%	10.9%	9.5%	9.7%
BBB+	9.5%	9.4%	8.1%	9.0%	10.5%	11.2%	10.8%	10.8%
BBB	7.5%	8.2%	8.7%	8.1%	11.6%	9.5%	10.0%	10.4%
BBB-	7.3%	9.6%	7.5%	8.1%	8.7%	14.6%	10.4%	11.2%
BB+	6.4%	7.1%	5.4%	6.3%	11.3%	11.7%	8.6%	10.5%

Moody's

	25th Percentile ROE				75th Percentile ROE			
Credit Rating	2009	2010	2011	Average	2009	2010	2011	Average
A3	7.2%	10.4%	8.3%	8.7%	10.7%	11.1%	10.2%	10.7%
Baa1	8.6%	8.9%	7.9%	8.5%	10.1%	10.9%	10.6%	10.6%
Baa2	7.2%	7.8%	8.3%	7.8%	9.6%	10.8%	9.7%	10.0%
Baa3	7.1%	7.2%	5.8%	6.7%	9.9%	10.7%	9.7%	10.1%

Notes & Sources:
'Average' calculated as the average of the 2009, 2010, and 2011 ROEs, by Credit Rating.
Data excludes DP&L.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Net Income and Book Equity of Comparable Firms

Data: Historical
Type of Filing: Second Revised
Work Paper Reference No(s).:

Second Revised WJC-12.C
Page 1 of 1
Witness Responsible: William J. Chambers

	Credit Rating			Net Income			Book Equity			
Company Name	Fitch	S&P	Moodys	2009	2010	2011	2008	2009	2010	2011
Florida Power Corporation	BBB+	BBB+	Baa1	$462	$453	$314	$3,399	$4,490	$4,890	$4,675
Ohio Power Company	BBB+	BBB	Baa1	$578	$542	$465	$2,422	$3,235	$4,655	$4,450
Pacific Gas & Electric Company	BBB+	BBB	A3	$1,250	$1,121	$845	$9,529	$10,927	$11,463	$12,126
Public Service Co. of Colorado	BBB+	A-	Baa1	$323	$400	$397	$3,578	$3,746	$4,138	$4,306
South Carolina Electric & Gas Company	BBB+	BBB+	Baa2	$281	$290	$306	$2,704	$3,162	$3,437	$3,665
Tampa Electric Company	BBB+	BBB+	A3	$192	$243	$235	$2,091	$2,104	$2,158	$2,154
Union Electric Company	BBB+	BBB-	Baa2	$265	$369	$290	$3,449	$3,944	$4,073	$3,957
Virginia Electric and Power Company	BBB+	A-	A3	$356	$852	$822	$6,274	$7,173	$8,507	$8,750
Black Hills Power Inc.	BBB	BBB-	Baa2	$23	$31	$27	$255	$278	$309	$336
The Detroit Edison Company	BBB	BBB+	Baa1	$376	$441	$437	$3,556	$3,873	$4,009	$4,136
Monongahela Power Company	BBB	BBB-	Baa1	$0	$51	$1	$0	$0	$591	$550
NorthWestern Corporation	BBB	BBB	Baa1	$73	$77	$93	$764	$787	$820	$859
PacifiCorp	BBB	A-	Baa1	$542	$566	$555	$5,946	$6,607	$7,270	$7,271
Public Service Company of Oklahoma	BBB	BBB	Baa1	$76	$73	$125	$748	$812	$842	$893
Public Service Company of New Hampshire	BBB	A-	Baa2	$66	$90	$100	$634	$727	$926	$1,078
Southwestern Public Service Company	BBB	A-	Baa1	$68	$78	$90	$930	$950	$962	$1,077
Westar Energy, Inc.	BBB	BBB	Baa2	$175	$204	$230	$2,186	$2,245	$2,383	$2,769
Appalachian Power Company	BBB-	BBB	Baa2	$156	$137	$163	$2,377	$2,772	$2,822	$2,936
Arizona Public Service Company	BBB-	BBB	Baa1	$251	$336	$336	$3,339	$3,445	$3,825	$3,943
Consumers Energy Company	BBB-	BBB-	Baa2	$293	$434	$467	$3,705	$3,814	$4,136	$4,350
Empire District Electric Company	BBB-	BBB-	Baa2	$41	$47	$55	$529	$600	$658	$694
Indiana Michigan Power Company	BBB-	BBB	Baa2	$216	$126	$150	$1,435	$1,673	$1,694	$1,761
Indianapolis Power & Light Company	BBB-	BBB-	Baa2	$113	$120	$105	$750	$753	$759	$782
Kentucky Power Company	BBB-	BBB	Baa2	$24	$35	$42	$398	$432	$446	$460
Southwestern Electric Power Company	BBB-	BBB	Baa3	$114	$143	$161	$1,249	$1,524	$1,667	$1,813
Nevada Power Company	BB+	BB+	Baa3	$134	$186	$133	$2,628	$2,650	$2,762	$2,849
Sierra Pacific Power Company	BB+	BB+	Baa3	$73	$72	$60	$878	$1,009	$973	$975
Tucson Electric Power Company	BB+	BB+	Baa3	$91	$108	$85	$584	$643	$710	$825
			Minimum:	$0	$31	$1	$0	$0	$309	$336
			25th Percentile:	$73	$78	$92	$750	$779	$837	$884
			Median:	$165	$164	$162	$2,138	$2,175	$2,271	$2,461
			Average	$236	$272	$253	$2,369	$2,656	$2,925	$3,016
			75th Percentile	$301	$408	$351	$3,412	$3,763	$4,089	$4,178
			Maximum:	$1,250	$1,121	$845	$9,529	$10,927	$11,463	$12,126
The Dayton Power and Light Company	BBB-	BBB-	Baa2	$259	$278	$193	$1,475	$1,403	$1,380	$1,358

Notes & Sources:
Numbers in millions.
Fitch Credit Ratings from Fitch Ratings, U.S. Utilities, Power & Gas Financial Peer Study, June 2012, at 11–12.
S&P Credit Ratings from Thomson One and StandardAndPoors.com, as of June 22, 2012.
Moody's Credit Ratings from Moodys.com, as of June 22, 2012.
Financials from Capital IQ.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-UNC

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY
OF PHILIP R. HERRINGTON

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED TESTIMONY OF
PHILIP R. HERRINGTON

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Phil Herrington. My business address is 1065 Woodman Drive, Dayton, Ohio 45432.

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

A. I am President and Chief Executive Officer of DPL Inc., the parent company of The Dayton Power and Light Company ("DP&L" or "Company"), and President and Chief Executive Officer of DP&L.

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

A. I assumed my present position in March 2012. Prior to that, I was President of AES Global Wind Generation.

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

A. I received a B.S. degree in Chemical Engineering from the University of California at Santa Barbara in 1985 and a Masters in Business Administration from the University of Southern California Marshall School of Business in 1997. Before joining The AES Corporation (AES), I spent seventeen years at Edison Mission Energy, a subsidiary of California-based Edison International, in various leadership positions in development, asset management and engineering involving technologies including natural gas, wind and geothermal power generation. Prior to that, I was a project manager with Monsanto

Chemical's engineering group, and before then, served as a naval officer aboard nuclear submarines.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) provide an overview of DP&L's Electric Security Plan ("ESP") filing; and (2) demonstrate that DP&L's ESP filing promotes the policies of the State of Ohio.

II. OVERVIEW OF FILING

Q. Will you provide an overview of DP&L's ESP filing?

A. Yes. DP&L proposes an ESP pursuant to Ohio Revised Code § 4928.143. Under DP&L's ESP, DP&L's base generation rate would be a blend of DP&L's existing base generation rates and rates set through a competitive bidding process. The blending percentages that DP&L proposes are:

Date	Existing Rates	Competitive Bid
January 1, 2013 - May 31, 2014	90%	10%
June 1, 2014 - May 31, 2015	60%	40%
June 1, 2015 - May 31, 2016	30%	70%
June 1, 2016	0%	100%

DP&L's Rate Blending Plan is sponsored by Company Witness Dona Seger-Lawson. DP&L's competitive bidding plan is sponsored by Company Witness Robert Lee.

Q. Does DP&L seek a non-bypassable charge that would permit DP&L to stabilize and provide continuity regarding retail electric service?

A. Yes, DP&L seeks a non-bypassable Service Stability Rider (SSR) of $137.5 million per year during the ESP period to permit it to provide stable electric service. In the Commission's recent decision in American Electric Power-Ohio's (AEP-Ohio) ESP case, the Commission set a "reasonable revenue target that would allow AEP-Ohio an opportunity to earn somewhere within the seven to eleven percent range."[1] As explained in the testimony of Company Witness William Chambers (who sponsors DP&L's request for the SSR), an annual $137.5 million SSR would give DP&L an opportunity to earn a reasonable return on equity (ROE).

Q. Can you describe the interests that DP&L considered as DP&L established the terms and conditions of its ESP?

A. Yes. In considering the terms and conditions of the ESP filing, DP&L sought to balance the interests of customers, non-customer intervenors, and the Company. The goal of the filing is to allow DP&L the opportunity to maintain its financial integrity with the opportunity to earn a reasonable rate of return, while balancing the interests of other intervening parties. DP&L's ESP filing strikes an appropriate balance among those interests, since it will allow DP&L to maintain its financial integrity (as explained in Company Witness Chambers' testimony) while providing for competitive bidding on a timeline that is faster than the timeline authorized under the Market Rate Offer (MRO) statute (Ohio Revised Code § 4928.142).

Q. Does DP&L's ESP filing address the transfer of generation assets?

[1] Opinion and Order, p. 33 (Case No. 11-346-EL-SSO).

A. Yes. As explained in Company Witness Tim Rice's testimony, DP&L agrees make a separate application by December 31, 2013 to request the transfer of its generation assets. In this subsequent application, DP&L expects to request that the Commission authorize DP&L to transfer its generation assets by no later than December 31, 2017.

Q. Does DP&L's ESP filing promote competition?

A. Yes. As explained in the testimony of Company Witness Dona Seger-Lawson, DP&L's ESP filing contains six new provisions that will make it easier for CRES providers to do business in DP&L's certified territory.

Q. Does DP&L's ESP filing pass the "more favorable in the aggregate" test required by Ohio Revised Code §4928.143(C)(1)?

A. Yes. Company Witness Jeff Malinak's testimony supports the Company's determination that this ESP plan is more favorable in the aggregate that what would otherwise apply under an MRO.

III. ADVANCEMENT OF STATE POLICIES

Q. Are you familiar with the state policies contained in Ohio Revised Code § 4928.02?

A. Yes, I have studied the policies and I am familiar with them.

Q. Does DP&L's ESP filing advance those policies, and if so, how?

A. Yes, it does. As described below, DP&L's ESP filing advances many of the Ohio Revised Code §4928.02 policies. There are some policies in Ohio Revised Code §4928.02 that are unrelated to DP&L's ESP filing (e.g., those relating to transmission and distribution) that my testimony does not address; DP&L's ESP filing is consistent with those policies, as the filing does not adversely affect the achievement of those policies.

Q. Section 4928.02(A) states that it is the policy of the state to:

> **"Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. Through the ESP, DP&L will procure generation to satisfy a portion of its Standard Service Offer (SSO) obligations through a competitive bidding process (CBP). DP&L's customers should thus be assured of receiving reasonably priced retail electric service. Further, since only those suppliers that satisfy the financial and managerial criteria of DP&L's CBP will be allowed to bid, the consumer can be assured that the generation will be adequate, reliable, safe, efficient and nondiscriminatory.

Q. Section 4928.02(B) states that it is the policy of the state to:

> **"Ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. Through DP&L's ESP, SSO customers will over time receive generation through the CBP from the lowest bidder. Further, customers will retain the right to select any generation supplier from which they wish to buy.

Q. Section 4928.02(H) states that it is the policy of the state to:

> **"Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. DP&L's ESP filing advances this policy because DP&L will abide by its filed Corporate Separation Plan as amended and DP&L's filing describes its plan to request a transfer DP&L's generation assets into a separate affiliate.

Q. Section 4928.02(I) states that it is the policy of the state to:

> **"Ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. By conducting a CBP in which all qualified bidders are permitted to bid, DP&L's ESP should ensure that its customers receive the best available market price. Further, the CBP will be conducted in accordance with Commission rules, and will be managed by an independent third party auction manager, so that there should be no unreasonable sales practices, market deficiencies or exercise of market power.

Q. Section 4928.02(L) states that it is the policy of the state to:

> **"Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. DP&L's ESP protects at-risk populations by ensuring that they will receive the best available market price.

Q. Section 4928.02(N) states that it is the policy of the state to:

> **"Facilitate the state's effectiveness in the global economy. In carrying out this policy, the commission shall consider rules as they apply to the costs of electric distribution infrastructure, including, but not limited to, line extensions, for the purpose of development in this state."**

Does DP&L's ESP advance that policy, and if so, how?

A. Yes. DP&L's ESP will facilitate Ohio's effectiveness in the global economy by ensuring that Ohio businesses have access to market-based generation. In addition, competitive retail enhancements funded through DP&L's ESP will reduce administrative barriers and transaction costs that potentially affect the opportunities for CRES providers to encourage customers to switch to competitive suppliers. The overall design of the ESP, which allows DP&L to smoothly transition to market-based pricing, will have a positive influence on economic development initiatives within the state, enhancing Ohio's ability to compete in the global economy.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

PUBLIC VERSION

ELECTRIC SECURITY PLAN (ESP)

SECOND REVISED DIRECT TESTIMONY
OF ALDYN W. HOEKSTRA

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)

SECOND REVISED DIRECT TESTIMONY
OF ALDYN W. HOEKSTRA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Aldyn W. Hoekstra and my business address is 1065 Woodman Drive, Dayton, Ohio, 45432.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as Vice President, Merchant Portfolio Strategy.

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

A. I assumed my present position in July 2012.

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

A. In my current position, I report to the Senior Vice President, Competitive Market Services, and I have responsibility for managing the Company's Commercial Structuring function, which includes commodity pricing, deal structuring, portfolio management and term trading, portfolio analytics and business planning responsibilities.

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

A. I received a Bachelor of Science degree in Industrial Engineering from Purdue University in 1987 and a Master of Science degree in Engineering-Economic Systems from Stanford University in 1988. I have over 20 years of industry and consulting experience, focusing on North American energy markets, strategy and economics. Prior to joining DP&L, I spent over 15 years as a consulting energy economist with various firms, as well as 5 years as a member of the management team of Sempra Energy Solutions, most recently as the Vice President of Strategy and Risk Management.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission"), any other state commission, or the Federal Energy Regulatory Commission ("FERC")?

A. I have not previously provided testimony before the PUCO, but I have sponsored testimony before the California Public Utilities Commission (CPUC) and Public Utilities Commission of Nevada (PUCN) in the following matters:

- **CPUC Application Nos. 90-08-066, 90-08-067, 90-09-001:** Certificate of Public Convenience and Necessity for the California-Oregon Transmission Project; Testimony on behalf of Toward Utility Rate Normalization (1990)
- **PUCN Docket Nos. 02-12046 through 02-12054:** Applications of MGM Mirage, et. al., to purchase energy, capacity and/or ancillary services from a provider of new electric resources; Testimony on behalf of Sempra Energy Solutions (2003)
- **PUCN Docket Nos. 02-12053 and 02-12054:** Applications of MGM Mirage and Victoria Partners to purchase energy, capacity and/or ancillary services from a provider of new electric resources; Affidavit on behalf of MGM Mirage and Victoria Partners (2003)
- **CPUC Rulemaking No. 06-02-012:** Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program; Testimony on behalf of the Alliance for Retail Energy Markets (2006)

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the baseline volumes for DP&L distribution sales and DP&L Standard Service Offer (SSO) sales used for the projections of financial and rate impacts supported by other DP&L witnesses.

Q. What Workpapers are you supporting?

A. I am supporting Workpaper 8A "Distribution Sales Baseline Volumes" and Workpaper 8B "SSO Sales Baseline Volumes."

II. ***WORKPAPERS***

Q. Are you responsible for Workpaper 8A? If so, please describe what is provided on Workpaper 8A.

A. Yes. Workpaper 8A "Distribution Sales Baseline Volumes" shows actual, weather-normalized distribution sales volumes on the DP&L system for calendar year 2011, differentiated by customer revenue class, and displayed as an annualized total and also by month.

Q. What is the source of the information shown on Workpaper 8A?

A. The information on Workpaper 8A contains historical distribution sales data obtained from the Company's accounting records, kept in the ordinary course of business, as adjusted to account for the impact on weather-sensitive customer usage of differences between actual weather conditions during 2011 and long-term average weather conditions, specifically Heating Degree Days (HDD) and Cooling Degree Days (CDD).

Q. How was the information contained on Workpaper 8A developed?

A. The information on Workpaper 8A was developed by adjusting recorded 2011 distribution sales through the use of statistical regression equations that the Company uses to adjust actual sales data for weather-sensitive customers based on the difference between normal and actual HDDs and CDDs.

Q. How is the information on Workpaper 8A used in the Company's filing?

A. The information on Workpaper 8A is used by Company Witness Jackson for projections of the financial impacts of the Company's filing, by Company Witness Rabb to establish the rates for the Reconciliation Rider and to demonstrate how the Competitive Bidding Rate will be set, by Company Witness Parke to develop the Service Stability Rider, and by Company Witness Hale to establish the rates for the Transmission Cost Recovery Rider – Non-bypassable.

Q. Is the information provided on Workpaper 8A reasonable?

A. Yes, the distribution sales volumes shown in Workpaper 8A reflect actual, weather-normalized distribution sales for the most recently-completed calendar year of 2011. As a result, these annualized and weather-normalized distribution sales baseline volumes provide a reasonable basis for the projections of financial and rate impacts of the Company's Application which are supported by other DP&L witnesses.

Q. Are you responsible for Schedule Workpaper 8B? If, yes, please describe what is provided on Workpaper 8B.

A. Yes. Workpaper 8B "SSO Sales Baseline Volumes" shows annualized SSO sales volumes, consistent with the distribution sales volumes shown on Workpaper 8A, differentiated by customer revenue class, and displayed as an annualized total and also by month.

Q. What is the source of the information shown on Workpaper 8B?

A. The information on Workpaper 8B was developed from the annualized and weather-normalized distribution sales volumes shown on Workpaper 8A, as adjusted to remove sales to customer accounts that were known to have switched from SSO service to retail electric generation service from a Competitive Retail Electric Service (CRES) provider as of August 30, 2012, the date Workpaper 8B was prepared. The identification of accounts known to have switched to CRES providers as of that date was obtained from the Company's customer information records, kept in the ordinary course of business.

Q. How was the information contained on Workpaper 8B developed?

A. The information on Workpaper 8B was developed by subtracting, from the distribution sales volumes shown on Workpaper 8A, the most recent 12 months' usage for accounts that had switched to CRES service as of August 30, 2012.

Q. How is the information on Workpaper 8B used in the Company's filing?

A. The information on Workpaper 8B is used by Company Witness Jackson for projections of the financial impacts of the Company's filing, by Company Witness Rabb to demonstrate how the Competitive Bidding Rate will be set, and by Company Witness Parke to demonstrate how the Competitive Bid True-up rate will be established on Schedule 7B.

Q. Is the information provided in Workpaper 8B reasonable?

A. Yes, the SSO sales baseline volumes shown on Workpaper 8B reflect annualized and weather-normalized sales to the customer accounts that are being served under DP&L's SSO tariff based on actual currently-known customer switching. As a result, these annualized and weather-normalized SSO sales baseline volumes provide a reasonable basis for the projections of financial and rate impacts of the Company's Application which are supported by other DP&L witnesses.

III. CUSTOMER SWITCHING

Q. What was the level of customer switching from the Standard Service Offer (SSO) tariff to Competitive Retail Electric Service ("CRES") suppliers in DP&L's service territory as of the date Workpaper 8B was prepared?

A. As of August 30, 2012, the percentage of DP&L distribution load, expressed on an annualized forward-looking basis as a percentage of the overall distribution sales volumes shown on Workpaper 8B, that has switched from the SSO tariff to CRES suppliers is:

- Residential 24.7%
- Non-residential 84.0%
- Total System: 61.7%.

Q. In the most recent quarterly PUCO summary of switch rates from electric distribution utilities (EDU) shows that 18.37% of residential load, 83% of non-residential load, and 58.57% of overall load had switched from DP&L to a CRES provider as of June 30, 2012. The data from this PUCO switching report is lower than the switching statistics you provided above—are both sets of numbers correct?

A. Yes, both sets of numbers are correct.

Q. If both sets of numbers are correct, how do you reconcile the differences between them?

A. The switching rates provided above as of August 30, 2012 include the annualized usage of customer accounts that were known to have switched to CRES service even if that CRES service may not have actually started. Thus, these numbers reflect switching rates expressed on an **annualized, forward-looking basis**, consistent with the baseline volumes for DP&L distribution sales and DP&L Standard Service Offer (SSO) sales provided in Workpaper 8A and Workpaper 8B, respectively.

In contrast, DP&L switching rates found in the quarterly PUCO report dated June 30, 2012 are based solely on sales billed in the month of June 2012. This data is reported as required by the PUCO. Therefore, the **historical, backward-looking** switching rates in the PUCO quarterly reports is a ratio derived by dividing CRES supplier sales from DP&L distribution sales for billed meter reads that DP&L recorded throughout the month of June 2012.

Q. What is the basis for the large switching level in non-residential customer load?

A. The switching level for non-residential customers is already high relative to residential switching because of early switching in non-residential sectors as a result of direct sales efforts by CRES providers since the current ESP was implemented in 2009.

Q. Does DP&L expect switching rates to remain at the levels as of August 30, 2012?

A. No, DP&L expects switching to increase as more residential and small commercial customers switch from the SSO tariff in the current environment of low market prices, whether in the form of "organic" switching by individual customer choice, or in the form of government aggregation.

Q. What level of customer switching does DP&L project over the term of the filed Electric Security Plan ("ESP")?

A. DP&L projects that by the end of 2012 customer switching will increase to an annualized rate of [redacted]% among residential customers, [redacted]% among non-residential customers and [redacted]% overall for the DP&L system, Projected switching rates at the end of subsequent years of the ESP term are provided in the table below.

Realized & Projected Annualized Switching in DP&L Territory*

**as of year end*	2011	2012	2013	2014	2015	2016	2017
Residential	12.8%	[redacted]					
Non-Residential	77.8%						
Overall	53.0%						

Q. What is the basis for DP&L's expectation of increased residential switching?

A. These projected switching rates are based on an analysis of current and historical switching levels in the DP&L service territory, combined with future projections that reflect these historical trends and projections of how the marketplace is expected to change over the ESP term. For example, increased competition for residential customers has led to an increase in the entry of additional third-party CRES suppliers into the residential marketplace, and simultaneously an increased level of switching among residential customer load. DP&L's projection of increased residential switching is in part due to this observed increase in marketing and sales efforts directed towards residential customers, and an expectation that it will continue if the Company's ESP proposal in this case is approved as filed.

Q. Are you aware of any other factors that could provide additional opportunities for customer switching?

A. Yes, I believe that increased switching in the residential and small commercial sectors will be driven in part through increases in opt-out governmental aggregation programs conducted by communities that pass ballot initiatives to implement them. The chart below provides the forecasted growth in aggregation-derived and organically switched load as compared to the corresponding decline in load remaining on the SSO tariff. The chart shows how switching is projected to increase due to the effects of communities implementing opt-out government aggregation programs.

[redacted]

Total Expected Aggregation Load (GWh)					
	2013	**2014**	**2015**	**2016**	**2017**
Load Already Aggregated as of 8/30/2012	40	40	40	40	40
Projected Cumulative Residential Switched Load due to Aggregation	[redacted]				
Total					

IV. OTHER

Q. Do you adopt the testimony of Company Witness Teresa Marrinan?

A. Yes. I am adopting her Second Revised testimony.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

PUBLIC VERSION

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY
OF CRAIG L. JACKSON

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED TESTIMONY OF
CRAIG L. JACKSON

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Craig Jackson and my business address is 1065 Woodman Drive, Dayton, Ohio, 45432.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as Senior Vice President and Chief Financial Officer.

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

A. I assumed my present position in May 2012.

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

A. In my current position, I report to the Company's President and Chief Executive Officer and have direct responsibility and oversight for the Company's accounting, tax, financial planning, treasury, risk management, and internal audit functions.

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

A. I received a Bachelor of Science degree in Business Administration from Bloomsburg University in 1996. I also earned a Master of Business Administration degree in Finance from Wright State University in 2001.

I joined DP&L in February 2000 as a Financial Analyst, Corporate Modeling. In December 2002, I accepted the position of Team Leader, ISO Settlements, with PPL Corporation. In June 2004, I returned to DPL as Manager, Financial Planning and

Analysis, reporting to the Chief Financial Officer. From June 2004 to May 2012, I was promoted through several positions of increasing responsibility within the Treasury organization at DP&L, the last of which was as Vice President and Treasurer.

Prior to joining DP&L in February of 2000, I served in the United States Air Force ("Air Force") as a Finance Technician. I began my service with the Air Force in May 1996.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to support: (1) the Company's pro forma financial projections for the period of this ESP (January 2013 through December 2017); and (2) the Company's cost of debt calculations.

Q. Please summarize the results from the pro forma financial statements.

A. The pro forma Income Statement, Balance Sheet, and Cash Flow for DP&L for the 2013 through 2017 period are provided on Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 respectively. As shown on Second Revised Exhibit CLJ-2, Line 35, the Company projects its average annual return on equity (ROE) to decline from approximately [redacted] in 2013 to approximately [redacted] in 2017, with a 5-year weighted average annual ROE of approximately [redacted]. The decline in the forecasted ROE is driven by low forward commodity prices, customer shopping realized as of August 30, 2012, and the Company's transition to 100% auction, only partially offset by the annual recovery of [redacted] million through the Company's proposed service stability rider.

Q. Do the financial results in Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 reflect corrections to errors that were discovered in DP&L's October 2012 filing in this proceeding?

A. Yes, DP&L recently discovered certain errors in the projected revenues and expenses that were incorporated into the financial results contained in the October 2012 filing, which are being corrected in this Second Revised filing.

Q. What are these errors?

A. The errors that are being corrected in this filing can be grouped into four categories as described below.

1. **Revenues/Load Expense Errors.** The October 2012 filing misstated DP&L's projected revenues and purchased power expenses because of formula errors in a spreadsheet model supporting DP&L's financial projections that produced incorrect references to source data and inaccurate calculations;

2. **Fuel Rider Rate Error.** The October 2012 filing misstated DP&L's projected revenues because the projected Fuel rider rate erroneously excluded an upward adjustment to account for distribution losses;

3. **CBP Auction Price Error.** The October 2012 filing misstated DP&L's projected CBP revenues and purchased power expenses because the projected CBP auction price was not appropriately adjusted for distribution losses, the filed auction schedule and the updated auction proxy scaling factor. This change did not impact the estimated CBP auction results that are supported by Company Witness Teresa Marrinan;

4. **Property Tax Error.** The October 2012 filing misstated DP&L's projected property tax expenses during certain years.

Q. What is the effect of correcting these errors?

A. Correcting the errors results in a $135 million and $121 million reduction in the projected gross margin and operating income, respectively, to be recovered by DP&L over the 5 year period of 2013-2017, as detailed in the table below. (Note: The table below does not include the impact of DP&L's recently disclosed asset impairment which is further discussed below.)

		Error		5-Year (2013-2017) Impact of Correcting Error
1		**Revenue/Load Expense Errors**		
	a	SSO Non-CBP Load Expense Calculation	$	(165.7)
	b	SSO CBP Load Expense Calculation	$	4.3
	c	Wholesale Revenue Calculation	$	12.7
		Item 1	**$**	**(148.8)**
2		**Fuel Rider Error**	**$**	**14.1**
3		**CBP Auction Price Error**	**$**	**(0.3)**
		Gross Margin Impact (Items 1-3)	**$**	**(134.9)**
4		**Property Tax Error**	**$**	**13.9**
		Operating Income Impact (Items 1-4)	**$**	**(121.0)**

Q. Do the financial results include the impact from DP&L's recently disclosed fixed asset impairment?

A. Yes.

Q. What impact does the fixed asset impairment have on the pro forma financial statements?

A. The fixed asset impairment resulted in an $80.8 million (pre-tax) write-off. This write-off was specific to DP&L's Conesville and Hutchings generating facilities and was disclosed in DP&L's SEC Form 10Q/A for the quarterly period ended September 30, 2012. As a result of this write-down, the forecasted common shareholder's equity balance, as shown on Second Revised Exhibit CLJ-3, was negatively impacted by approximately $52 million (the after tax impact of the write-down). Additionally, the forecasted depreciation expense, as shown on Second Revised Exhibit CLJ-2, includes a total reduction of approximately $30 million over the ESP period as a result of the write-down.

Q. Do the financial results include the impact of customer switching?

A. The financial results include the impact of customers that have switched as of August 30, 2012; however, the results do <u>not</u> include incremental switching after August 30, 2012. To the extent that additional switching occurs beyond the level at August 30, 2012, DP&L's earnings and return on equity will be negatively impacted. The switching tracker (described below) would moderate the impact of additional customer switching.

Q. Explain the Company's justification for the service stability rider (SSR).

A. The amount and duration of the service stability rider is critical for the Company to maintain its financial integrity and to have the opportunity to earn a reasonable rate of return as described by Company Witness Chambers' testimony in this case. As shown on Second Revised Exhibit CLJ-2, Line 45, the exclusion of the service stability rider would be disastrous for the Company as it would result in [redacted]. Furthermore, if additional retail switching occurs beyond the August 30, 2012 level, then the [redacted].

III. FINANCIAL STATEMENTS

Q. Does DP&L's Application comply with Ohio Administrative Code § 4901:1-35-03, and if so, how?

A. Yes. In seeking approval of the Electric Security Plan ("ESP"), the Company must meet certain filing requirements as described in OAC §4901:1-35-03. These include the requirement that the Company provide pro forma financial projections for the filing period (2013 – 2017) as well as calculations of its projected return on equity for each year of the ESP. The code also requires balances sheet and income statement information along with the methodology and assumptions for these projections. DP&L satisfies these requirements by providing financial projections including balance sheet, income statements, cash flow statements and return on equity projections for every year of the ESP period (2013 through 2017). The projections are included in Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4.

Q. What methodology and associated processes were used to develop the pro forma financial statements?

A. The pro forma financial statements included in Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 reflect the projected financial impact of the Company's filed ESP and were developed consistent with the methodology and process used by the Company for preparing its normal operating forecast. This methodology is a "bottom up" approach to forecasting that requires input and assumptions from a variety of areas within the Company. The assumptions, which include distribution sales, Standard Service Offer ("SSO") sales, customer shopping, generation plant characteristics, commodity price curves, and fuel and operating cost projections, among others, are reviewed with the business areas to determine the most reasonable set of assumptions to be incorporated into the forecast. As we progress through the business year, we track and monitor actual results compared to the forecast. Based on actual results combined with potential changes in business and market conditions, the forecast is adjusted as needed. This process makes the forecast a reliable one.

Q. What are the major components of in the financial forecast?

A. The inputs and assumptions received from the various areas within the Company are used to derive the following major components of the forecast:

(1) distribution baseline sales volumes and SSO baseline sales volumes;

(2) commodity price forecast;

(3) generation dispatch forecast;

(4) retail and wholesale revenue estimates;

(5) operations and maintenance expenses forecast; and

(6) capital expenditures forecast.

Q. How are each of the above components developed?

A. The development and methodology for each of these major components are as follows:

(1) Distribution Sales and SSO Sales – The development of the distribution baseline sales volumes and SSO baseline sales volumes are described in Company Witness Hoekstra's testimony in this case.

(2) Commodity Price Forecast – The Company does not develop internal commodity price curve forecasts. We utilize publically available forward market curves in the Company's forecast.

(3) Generation Dispatch Forecast – The generation dispatch forecast, combined with forecasted energy purchases, is modeled to meet sufficiently the Company's anticipated total energy requirements. Based on a number of assumptions, including plant operational characteristics, planned outages, plant availability, variable costs, and forward market curves, we model, by generating unit, the estimated generation megawatt hours, the cost of fuel consumed, variable production costs, and costs associated with the operation of environmental equipment. In addition to fuel and other generation-related costs, we model and forecast purchased power costs.

(4) Retail and Wholesale Revenue Estimates – Retail revenue estimates for customers under DP&L's SSO rates are developed by customer class. The retail revenues reflected in the Company's pro forma financials include existing tariff rates, adjustments to retail riders that are cost trackers (such as the fuel adjustment clause), the effects of the ESP (including the impact that the Competitive Bid Process has on retail rates), and the distribution baseline sales volumes and SSO baseline sales volumes described earlier.

Wholesale revenues estimates include: (a) known special contracts, which are developed according to the terms of the contracts; (b) known forward wholesale agreements, which are developed according to the terms of the agreements; and (c) spot market wholesale sales, which are not committed or known sales when the forecast is developed, but are projected based on forecasted generation output and expected wholesale market prices.

(5) Operations and Maintenance ("O&M") Expense Forecast – O&M expenses are forecasted by (and reviewed with) all of the business areas within the Company. Underlying the O&M forecast are assumptions for various items such as projected salary increases and inflationary factors. Each area's O&M forecast includes staffing plans, labor costs, and other operational costs necessary to perform the functions of the specific area.

(6) Capital Expenditures Forecast – Capital expenditures are forecasted by (and reviewed with) all of the relevant business areas within the Company, although a substantial portion of the forecast is driven by the Company's operational groups: Transmission; Distribution; and Generation. The forecast includes specific projects with estimated in-service dates as well as dollars allocated to fund smaller projects under a blanket capital budget. The capital expenditures and related in-service dates are used to estimate book depreciation, tax depreciation, and capitalized interest.

Q. What assumptions did you make regarding the Company's transition to 100% market?

A. The Company's transition to market is to begin on January 1, 2013 with 10% of the SSO load being procured via the competitive bidding process (CBP). Beginning June 1 of each year thereafter, the cumulative percentage of SSO load procured through the CBP will be as follows:

2014: 40%

2015: 70%

2016: 100%

The Company's transition to market will be completed in June of 2016, when 100% of the cumulative standard service offer load is acquired through the CBP.

Q. How does DP&L account for the SSO load that DPL Energy Resources, LLC (DPL Inc.'s retail marketer) acquires from DP&L?

A. DPL Energy Resources procures its power, through contracted prices, from DP&L at market rates. The revenues associated with the contracted prices are reflected in DP&L's revenues on Second Revised Exhibit CLJ-2. Additionally, the costs to supply the power to DPL Energy Resources are reflected in DP&L's fuel and purchased costs shown on Second Revised Exhibit CLJ-2.

Q. Have you considered or factored into the pro forma financial statements the transfer of generating assets outside of the Company?

A. No. We have not included the effect of legally transferring the generation assets, in the pro forma financial statements shown on Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4.

Q. What are DP&L's plans for the $470 million, 5.125% First Mortgage Bonds due October 2013?

A. At this time, DP&L's plan is to refinance the $470 million, 5.125% First Mortgage Bonds due October 2013 at or prior to maturity. The pro forma financial statements included in Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 assume that the bonds are refinanced on October 1, 2013 at an interest rate of 5.125%.

Q. Do you anticipate issuing new (incremental) long-term debt at DP&L over the forecast period?

A. No, not at this time.

Q. Can you describe how the Company's proposed switching tracker account would function?

A. Yes. The switching tracker account would defer for later recovery from customers the difference between the level of switching experienced as of August 30, 2012 (62% of retail load) and the actual level of switching. The tracker would begin with the start of the ESP and end in June 1, 2016 when DP&L would procure 100% of its supply needs through the CBP.

Q. What is the formula to determine the dollars added to the tracker account?

A. Each month, DP&L will calculate the percentage of switching that has occurred since August 30, 2012. The difference, multiplied by distribution load equals the quantity subject to the switching tracker. The cost subject to the switching tracker will equal the difference between the Blended SSO rate and the CB rate in effect. That difference (in $/MWh) multiplied by the quantity (in MWh) equals the dollars to be added to the switching tracker for the month.

Q. How will the switching tracker be accounted for?

A. Each month the dollars associated with the tracker will be placed in a regulatory asset account that will accrue carrying charges equal to DP&L's June 30, 2012 embedded cost of long-term debt as shown on WP-12.2. An example of the calculation of the tracker is shown in Exhibit CLJ-5.

Q. How does the Company propose to recover the switching tracker?

A. The Company seeks to recover the balance from all customers beginning January 1, 2014 until the deferral balance plus carrying costs are at a zero balance.

Q. Why is this tracker necessary?

A. The projected financial results which I've described earlier are those which are expected to occur using the assumption of no new incremental switching. Using this assumption and even with the SSR as proposed, the Company projects its ROE to average [redacted] over the period of the ESP. Any further losses due to switching would create a significant strain to the financial integrity of the Company, as more fully discussed in the testimony of Company Witness Chambers. The switching tracker as proposed would help protect the Company from further financial deterioration should switching continue to increase during the terms of the proposed ESP.

Q. Will the switching tracker recover all of the lost margin realized through incremental switching?

A. Not necessarily. It is possible that the Company might have procured power at costs below the CBP. The switching tracker will not recover this portion of the lost margin.

Q. Does the switching tracker guarantee DP&L will earn a reasonable ROE?

A. No. The switching tracker, along with the Service Stability Rider, allows DP&L the opportunity to earn a reasonable ROE, but does not guarantee a reasonable ROE. There are other factors and components that impact the financial projections and results of the company. These components were discussed earlier in my testimony.

Q. What has caused DP&L's ROE to decline over the past few years?

A. DP&L has experienced a declining ROE since 2010, primarily driven by increased customer shopping and declining capacity and wholesale power prices, as shown on Second Revised Exhibit CLJ-1.

IV. COST OF LONG-TERM DEBT

Q. Are there any noteworthy issues with the Company's long-term debt and associated annual interest expense?

A. Yes. The Company's debt portfolio includes $100 million of Pollution Control Bonds (PCBs) that mature on November 1, 2040. The bonds were issued with a variable rate that is indexed to the rate of the Securities Industry and Financial Markets Association (SIFMA) and is reset weekly. The Company's calculated average cost of debt, as of June 30, 2012, includes annualized interest costs related to the PCBs based on variable rates at June 30, 2012. Future interest costs related to the PCBs will be dependent upon the variable interest rate which will fluctuate due to market conditions and rates.

Additionally, this debt is backed by a bank-supported credit facility. The facility has a maturity date of December 9, 2013. Fees on this facility vary depending on the Company's credit rating. We are currently at the bottom pricing level of the credit rating grid. The pro forma financials on Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 assume no increases to our current fees.

Q. What is the Company's average cost of debt?

A. The Company's embedded cost of debt, as of June 30, 2012, was 4.943%.

Q. Please explain the basis for the Company's average cost of debt calculation.

A. WP-12.2 details the Company's average cost debt as of June 30, 2012. It is a function of the Company's long-term debt carrying value and its annualized long-term debt interest expense.

Q. How is the Company's cost of long-term debt used in this filing?

A. The Company's cost of long-term debt is used in the Reconciliation Rider referenced in WP-7A.1, the CBT Rider referenced in WP-7B, and will be used to calculate carrying costs on the deferral balances for all riders that are considered trackers.

V. WORKPAPERS

Q. What Workpapers and Exhibits are you supporting?

A. I am sponsoring the following Workpapers and Exhibits, which satisfy the requirements set forth in Ohio Administrative Code §4901:1-35-03.

1. WP-12.2: Embedded Cost of Long-Term Debt
2. WP-12.3: Unamortized Issuance Expense on Long-Term Debt

3. WP-12.4: Unamortized (Discount) or Premium and Unamortized Gain or (Loss)

4. WP-12.5: Annual Interest Cost Calculation

5. Second Revised Exhibit CLJ-1: Overview of Historical Returns on Equity

6. Second Revised Exhibit CLJ-2: Projected Statements of Income

7. Second Revised Exhibit CLJ-3: Projected Balance Sheet

8. Second Revised Exhibit CLJ-4: Projected Statements of Cash Flow

9. Exhibit CLJ-5: Methodology Used to Calculate the Switching Tracker

10. Exhibit CLJ-6: Monthly Calculations for Illustrative Switching Tracker

Q. Please identify and describe Workpaper 12.2

A. Workpaper 12.2 provides the Embedded Cost of Long-term Debt for the Company as of June 30, 2012.

Q. Please identify and describe Workpaper 12.3

A. Workpaper 12.3 provides the Unamortized Issuance Expense on Long-Term Debt as of June 30, 2012.

Q. Please identify and describe Workpaper 12.4

A. Workpaper 12.4 is the Unamortized (Discount) or Premium and Unamortized Gain or (Loss) as of June 30, 2012.

Q. Please identify and describe Workpaper 12.5

A. Workpaper 12.5 is the Annual Interest Cost Calculation.

Q. What is the source of the information shown on Work papers 12.3, 12.4, and 12.5?

A. The source of information for workpapers 12.4, 12.5, and 12.5 is the Company's actual long-term debt carrying value at June 30, 2012 and annualized 2012 interest expense. Additionally, the interest expense related to the variable rate PCBs was adjusted to reflect variable rates at June 30, 2012.

Q. Are unamortized issue costs, discounts and premiums balances and expenses included in the average cost of debt calculation?

A. Yes. WP-12.3, WP-12.4 and WP-12.5 detail the unamortized balances and expenses that are included in the average cost of debt calculation.

Q. Please identify and describe Second Revised Exhibit CLJ-1.

A. Second Revised Exhibit CLJ-1 is an overview of historical returns on equity for the years 2010 – 2012. Data for 2012 includes actual and projected information.

Q. Please identify and describe Second Revised Exhibit CLJ-2.

A. Second Revised Exhibit CLJ-2 is the pro forma Statements of Income for the Company for the years 2013 through 2017 and also includes projected ROEs for that same period.

Q. Please identify and describe Second Revised Exhibit CLJ-3.

A. Second Revised Exhibit CLJ-3 is the pro forma Balance Sheet for the Company for the years ending December 31, 2013 through 2017.

Q. Please identify and describe Second Revised Exhibit CLJ-4.

A. Second Revised Exhibit CLJ-4 is the pro forma Statements of Cash Flow for the Company for the years ending December 31, 2013 through 2017.

Q. Please identify and describe Exhibit CLJ-5.

A. Exhibit CLJ-5 provides the detail supporting the methodology used to calculate the switching tracker along with illustrative calculations.

Q. Please identify and describe Exhibit CLJ-6.

A. Exhibit CLJ-6 provides the detail supporting the illustrative monthly switching tracker calculations.

Q. Are the pro forma statements included in Second Revised Exhibit CLJ-2, CLJ-3 and CLJ-4 accurate?

A. Based on the various assumptions and input received, and the review of them that the Company performed, including the corrections described and quantified above, the statements are accurate.

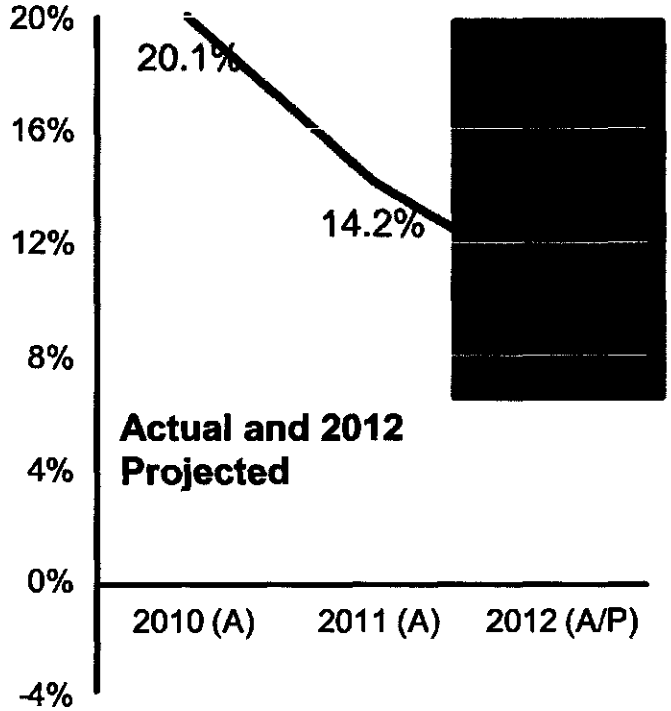
VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Overview of Historical Return on Equity
2010 Actual - 2012 Estimate

DP&L Combined ROE



	2010	2011	2012
Wholesale Energy ($/MWH)	38.4	40.7	[redacted]
Wholesale Capacity Price ($/MW-Day)	144	137	
Switched Load	32%	47%	

Note: In the graph above, (A) = Actual, (A/P) = 8 months actual, 4 months projected;

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Projected Statements of Income (unaudited) ($ in millions)
2013 - 2017

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

Second Revised Exhibit CLJ-2

Witness Responsible: Craig Jackson

Line No. (A)	Description (B)	2013 (C)	2014 (D)	2015 (E)	2016 (F)	2017 (G)	Source (H)
1	Operating Revenues						
2	Retail	[redacted]					Internal Documents
3	Service Stability rider*						Internal Documents
4	Wholesale						Internal Documents
5	RTO Capacity and Other RTO Revenues						Internal Documents
6	Other Revenues						Internal Documents
7	Total Revenues						Sum Lines 2 thru 6
8							
9	Fuel and Purchased Power						
10	Fuel Costs	[redacted]					Internal Documents
11	Purchased Power						Internal Documents
12	Total Fuel and Purchased Power						Line 10 + Line 11
13							
14	Gross Margin	[redacted]					Line 7 - Line 12
15							
16	Operating Expenses						
17	Operation and Maintenance	[redacted]					Internal Documents
18	Depreciation and Amortization						Internal Documents
19	General Taxes						Internal Documents
20	Total Operating Expenses						Sum Lines 17 thru 19
21							
22	Operating Income	[redacted]					Line 14 - Line 20
23							
24	Interest Expense	[redacted]					Internal Documents
25	Other Income (Deductions)						Internal Documents
26							
27	Earnings Before Income Tax	[redacted]					Line 22 + Line 24 + Line 25
28							
29	Income Tax	[redacted]					Internal Documents
30							
31	Net Income	[redacted]					Line 27 - Line 29
32							
33	Common Shareholder's Equity	[redacted]					WP-12.1, Line 18
34							
35	Average Annual Return on Equity (ROE)	[redacted]					Line 31 / Line 33**
36	5-Year Weighted Average Return on Equity						Sum of Line 31 / Sum of Line 33
37							
38	***Service Stability Rider Sensitivity***						
39	Earnings Before Income Tax, excluding Service Stability Rider	[redacted]					Line 27 - Line 3
40							
41	Net Income, excluding Service Stability Rider	[redacted]					Line 39 x (1 - 35.8%)
42							
43	Common Shareholder's Equity, excluding Service Stability Rider	[redacted]					Line 33 - (Line 31 - Line 41)
44							
45	Average Annual Return on Equity (ROE), excluding Service Stability Rider	[redacted]					Line 41 / Line 43***
46	5-Year Weighted Average Return on Equity, excluding Service Stability Rider						Sum of Line 41 / Sum of Line 43
47							

48 *The Service Stability Rider has been rounded from $137.5 million to $138 million in this schedule.
49 **For purposes of this calculation, the average of the current year and prior year common shareholder's equity value (Line 33) is used.
50 ***For purposes of this calculation, the average of the current year and prior year common shareholder's equity value (Line 43) is used.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Projected Balance Sheet (unaudited) ($ in millions)
2013 - 2017

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

Exhibit CLJ-3

Witness Responsible: Craig Jackson

Line No. (A)	Description (B)	2013 (C)	2014 (D)	2015 (E)	2016 (F)	2017 (G)	Source (H)
1	Assets						
2	Total Current Assets	[redacted]					Internal Documents
3							
4	Property, Plant and Equipment						
5	Property, Plant and Equipment	[redacted]					Internal Documents
6	Accumulated depreciation and amortization						Internal Documents
7	Total Property, Plant and Equipment						Line 5 + Line 6
8							
9	Total Other Noncurrent Assets	[redacted]					Internal Documents
10							
11	Total Assets	[redacted]					Line 2 + Line 7 +Line 9
12							
13							
14	Liabilities and Shareholder's Equity						
15	Current and Non Current Liabilities	[redacted]					Internal Documents
16							
17	Capitalization						
18	Common Shareholder's Equity	[redacted]					Internal Documents
19	Preferred Stock						Internal Documents
20	Total Long Term Debt						Internal Documents
21	Total Capitalization						Sum Lines 18 thru 20
22							
23	Total Liabilities and Shareholder's Equity	[redacted]					Line 15 + Line 21

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Projected Statements of Cash Flows (unaudited) ($ in millions)
2013 - 2017

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

Exhibit CLJ-4
Page 1 of 1
Witness Responsible: Craig Jackson

Line No.	Description	2013	2014	2015	2016	2017	Source
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1							
2	Net cash provided by operating activities	[redacted]					Internal Documents
3							
4	Net cash used for investing activities	[redacted]					Internal Documents
5							
6	Net cash used for financing activities	[redacted]					Internal Documents
7							
8	Cash and Cash Equivalents:						
9	Net Change	[redacted]					Line 2 + Line 4 +Line 6
10	Balance at beginning of period						Prior column, Line 11
11	Cash and cash equivalents at end of period						Line 9 + Line 10
12							
13							
14							
15							
16							
17							

Methodology Used to Calculate The Switching Tracker

The switching tracker is intended to allow recovery of some of the lost gross margin that DP&L would experience due to increases in switching levels above those observed on August 30, 2012. It will be calculated on a monthly basis by multiplying the level of incremental load that has switched by the lost revenue opportunity. The calculation of these two values – the level of incremental switched load and the lost revenue opportunity – is described in detail below. This is followed by an illustrative calculation of the switching tracker if switching levels of 70% were observed in the future. The actual levels of future customer switching are unknown at this time.

Calculation of Incremental Switched Load

DP&L has developed a monthly forecast of retained load, shown in Workpaper 8B, and a monthly forecast of distribution load, shown in Workpaper 8A. These forecasts were based on the level of switching observed on August 30, 2012, approximately 62%. DP&L will compare the realized level of switching, measured as a percentage of the then-current distribution load, to the level of switching underlying the forecasts in Workpapers 8A and 8B. Any observed increase in switching will be multiplied by the monthly forecast of distribution load shown in Workpaper 8A to determine the level of incremental switched load used to calculate the switching tracker.

Below is an example of this calculation for calendar year 2013, assuming switching levels of 70%.

Illustrative Calculation of Incremental Switching in 2013 with 70% Switching

		2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Source
1	Distribution Load (GWh)	13,822	1,306	1,131	1,138	999	1,042	1,167	1,325	1,295	1,082	1,037	1,065	1,235	*Workpaper 8A*
2	Forecasted SSO Load (GWh)	5,294	584	451	461	345	353	421	528	502	368	355	395	531	*Workpaper 8B*
3															
4	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
5	Forecasted Level of Switching (%)	62%	55%	60%	60%	65%	66%	64%	60%	61%	66%	66%	63%	57%	*1 - Row 2 / Row 1*
6	Incremental Switching Load (%)	8%	15%	10%	10%	5%	4%	6%	10%	9%	4%	4%	7%	13%	*Row 4 - Row 5*
7															
8	Incremental Switched Load (GWh)	1,147	193	112	119	45	41	71	130	114	43	44	75	161	*Row 6 * Row 1*

Calculation of Lost Revenue Opportunity

When customers shop, rather than provide electricity at the blended SSO price, DP&L will sell freed-up electricity at then-current market prices. The lost revenue opportunity will be determined by comparing the blended bypassable SSO price, excluding the AER, to the auction clearing price for the period most closely aligned with the relevant delivery period. The blended bypassable SSO price, for the purposes of determining the switching tracker value, will be calculated by blending the applicable market blending percentage of the CB Auction Price with the average Current Adjusted Legacy ESP Rate underlying Schedule 8 (*i.e.*, $76.62/MWh, as shown in my supporting calculations in Exhibit CLJ-6).

Below is an example of this calculation for calendar year 2013.

Illustrative Calculation of Lost Revenue Opportunity in 2013

		2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Source
1	Blended SSO Rate ($/MWh)	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	*Calculated from Schedule 8*
2	Benchmark CB Rate ($/MWh)	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	*Exh. TFM-2, scaled to retail price*
3	Lost Revenue Opportunity ($/MWh)	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	*Row 1 - Row 2*

Calculation of Switching Tracker

The revenue booked through the switching tracker will be equal to the product of the incremental switched load and the lost revenue opportunity calculated by month. Below is the annual summary of these monthly calculations for the illustrative example. The full monthly calculations are included in my Exhibit CLJ-6, along with documentation of other supporting calculations.

Annual Summary of Illustrative Calculation Assuming 70% Switching

		2013	2014	2015	Jan 2016 - May 2016	Total	Source
1	Blended SSO Rate ($/MWh)	73.47	71.08	67.51	66.18	70.11	*Load Weighted Avg of Monthly Data*
2	Benchmark CB Auction Rate ($/MWh)	44.86	50.80	60.17	63.86	53.48	*Load Weighted Avg of Monthly Data*
3	Lost Revenue Opportunity ($/MWh)	28.61	20.28	7.34	2.32	16.63	*Row 1 - Row 2*
4							
5	Distribution Load (MWh)	13,822,395	13,822,395	13,822,395	5,616,782	47,083,967	*Sum of Monthly Data (WP8A)*
6	Forecasted SSO Load - 62% Switching (MWh)	5,293,868	5,293,868	5,293,868	2,194,758	18,076,363	*Sum of Monthly Data (WP8B)*
7							
8	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
9	Forecasted Level of Switching (%)	62%	62%	62%	61%	62%	*1 - Row 6 / Row 5*
10	Incremental Switching Load (%)	8%	8%	8%	9%	8%	*Row 8 - Row 9*
11							
12	Incremental Switched Load (MWh)	1,147,150	1,147,150	1,147,150	509,724	3,951,173	*Row 10 * Row 5*
13							
14	Revenue Booked in Switching Tracker ($MM)	32.8	23.3	8.4	1.2	65.7	*Row 3 * Row 12 / 10^6*

Witness Responsible: Craig Jackson

Monthly Calculations for Illustrative Switching Tracker

		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Source
1	Blended SSO Rate ($/MWh)	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	73.47	*Blended SSO Price*
2	Benchmark CB Auction Rate ($/MWh)	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	44.86	*Benchmark CB Auction Rate*
3	Lost Revenue Opportunity ($/MWh)	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	28.61	*Row 1 - Row 2*
4														
5	Distribution Load (MWh)	1,306,475	1,130,914	1,138,429	999,365	1,041,598	1,167,070	1,324,746	1,295,122	1,082,000	1,036,716	1,065,303	1,234,655	*Workpaper 8A, p 1, Line 8*
6	Forecasted SSO Load - 62% Switching (MWh)	584,496	451,277	460,610	344,973	353,402	420,845	527,667	502,099	367,524	355,000	394,557	531,418	*Workpaper 8B, p 1, Line 8*
7														
8	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
9	Forecasted Level of Switching (%)	55%	60%	60%	65%	66%	64%	60%	61%	66%	66%	63%	57%	*1 - Row 6 / Row 5*
10	Incremental Switching Load (%)	15%	10%	10%	5%	4%	6%	10%	9%	4%	4%	7%	13%	*Row 8 - Row 9*
11														
12	Incremental Switched Load (MWh)	192,553	112,003	119,081	45,163	40,923	70,724	130,243	113,562	42,923	43,985	74,966	161,021	*Row 10 * Row 5*
13														
14	Revenue Booked in Switching Tracker ($MM)	5.5	3.2	3.4	1.3	1.2	2.0	3.7	3.2	1.2	1.3	2.1	4.6	*Row 3 * Row 12 / 10^6*

		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Source
1	Blended SSO Rate ($/MWh)	73.47	73.47	73.47	73.47	73.47	69.18	69.18	69.18	69.18	69.18	69.18	69.18	*Blended SSO Price*
2	Benchmark CB Auction Rate ($/MWh)	44.86	44.86	44.86	44.86	44.86	55.56	55.56	55.56	55.56	55.56	55.56	55.56	*Benchmark CB Auction Rate*
3	Lost Revenue Opportunity ($/MWh)	28.61	28.61	28.61	28.61	28.61	13.62	13.62	13.62	13.62	13.62	13.62	13.62	*Row 1 - Row 2*
4														
5	Distribution Load (MWh)	1,306,475	1,130,914	1,138,429	999,365	1,041,598	1,167,070	1,324,746	1,295,122	1,082,000	1,036,716	1,065,303	1,234,655	*Workpaper 8A, p 1, Line 8*
6	Forecasted SSO Load - 62% Switching (MWh)	584,496	451,277	460,610	344,973	353,402	420,845	527,667	502,099	367,524	355,000	394,557	531,418	*Workpaper 8B, p 1, Line 8*
7														
8	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
9	Forecasted Level of Switching (%)	55%	60%	60%	65%	66%	64%	60%	61%	66%	66%	63%	57%	*1 - Row 6 / Row 5*
10	Incremental Switching Load (%)	15%	10%	10%	5%	4%	6%	10%	9%	4%	4%	7%	13%	*Row 8 - Row 9*
11														
12	Incremental Switched Load (MWh)	192,553	112,003	119,081	45,163	40,923	70,724	130,243	113,562	42,923	43,985	74,966	161,021	*Row 10 * Row 5*
13														
14	Revenue Booked in Switching Tracker ($MM)	5.5	3.2	3.4	1.3	1.2	1.0	1.8	1.5	0.6	0.6	1.0	2.2	*Row 3 * Row 12 / 10^6*

Witness Responsible: Craig Jackson

		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Source
1	Blended SSO Rate ($/MWh)	69.18	69.18	69.18	69.18	69.18	66.18	66.18	66.18	66.18	66.18	66.18	66.18	*Blended SSO Price*
2	Benchmark CB Auction Rate ($/MWh)	55.56	55.56	55.56	55.56	55.56	63.86	63.86	63.86	63.86	63.86	63.86	63.86	*Benchmark CB Auction Rate*
3	Lost Revenue Opportunity ($/MWh)	13.62	13.62	13.62	13.62	13.62	2.32	2.32	2.32	2.32	2.32	2.32	2.32	*Row 1 - Row 2*
4														
5	Distribution Load (MWh)	1,306,475	1,130,914	1,138,429	999,365	1,041,598	1,167,070	1,324,746	1,295,122	1,082,000	1,036,716	1,065,303	1,234,655	*Workpaper 8A, p 1, Line 8*
6	Forecasted SSO Load - 62% Switching (MWh)	584,496	451,277	460,610	344,973	353,402	420,845	527,667	502,099	367,524	355,000	394,557	531,418	*Workpaper 8B, p 1, Line 8*
7														
8	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
9	Forecasted Level of Switching (%)	55%	60%	60%	65%	66%	64%	60%	61%	66%	66%	63%	57%	*1 - Row 6 / Row 5*
10	Incremental Switching Load (%)	15%	10%	10%	5%	4%	6%	10%	9%	4%	4%	7%	13%	*Row 8 - Row 9*
11														
12	Incremental Switched Load (MWh)	192,553	112,003	119,081	45,163	40,923	70,724	130,243	113,562	42,923	43,985	74,966	161,021	*Row 10 * Row 5*
13														
14	Revenue Booked in Switching Tracker ($MM)	2.6	1.5	1.6	0.6	0.6	0.2	0.3	0.3	0.1	0.1	0.2	0.4	*Row 3 * Row 12 / 10^6*

		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Source
1	Blended SSO Rate ($/MWh)	66.18	66.18	66.18	66.18	66.18	*Blended SSO Price*
2	Benchmark CB Auction Rate ($/MWh)	63.86	63.86	63.86	63.86	63.86	*Benchmark CB Auction Rate*
3	Lost Revenue Opportunity ($/MWh)	2.32	2.32	2.32	2.32	2.32	*Row 1 - Row 2*
4							
5	Distribution Load (MWh)	1,306,475	1,130,914	1,138,429	999,365	1,041,598	*Workpaper 8A, p 1, Line 8*
6	Forecasted SSO Load - 62% Switching (MWh)	584,496	451,277	460,610	344,973	353,402	*Workpaper 8B, p 1, Line 8*
7							
8	Illustrative Level of Switching (%)	70%	70%	70%	70%	70%	*Illustrative Level of Switching*
9	Forecasted Level of Switching (%)	55%	60%	60%	65%	66%	*1 - Row 6 / Row 5*
10	Incremental Switching Load (%)	15%	10%	10%	5%	4%	*Row 8 - Row 9*
11							
12	Incremental Switched Load (MWh)	192,553	112,003	119,081	45,163	40,923	*Row 10 * Row 5*
13							
14	Revenue Booked in Switching Tracker ($MM)	0.4	0.3	0.3	0.1	0.1	*Row 3 * Row 12 / 10^6*

Determination of Blended SSO Rates

		Source			
1	**Period Start**		**1/1/2013**	**6/1/2014**	**6/1/2015**
2	**Period End**	*Source*	**5/31/2014**	**5/31/2015**	**5/31/2016**
3					
4	**Annual DP&L-Supplied SSO Revenue ($)**	*Schedule 8, Col (H), Line 54*	365,066,978	243,377,457	121,689,150
5	**Annual CB Auction SSO Revenue ($)**	*Schedule 8, Col (I), Line 54*	23,879,123	122,829,924	228,651,873
6	**Total Annual SSO Revenue ($)**	*Row 4 + Row 5*	388,946,101	366,207,381	350,341,023
7					
8	**Total Annual SSO Load (MWh)**	*WP8, p 5, Col (D), Line 2*	5,293,868	5,293,868	5,293,868
9					
10	**Blended SSO Rate ($/MWh)**	*Row 6 / Row 8*	73.47	69.18	66.18

Witness Responsible: Craig Jackson

Determination of Current Adjusted Bypassable Legacy ESP Rate

1	**Annual Adjusted Legacy ESP Revenue ($)**	*Schedule 8, p 1, Col (H), Line 54*	365,066,978
2			
3	**Market Blend %**	*CB Period 1 Blend %*	10.0%
4			
5	**Total Annual SSO Load (MWh)**	*WP8, p 5, Col (D), Line 2*	5,293,868
6	**Load Served by Legacy ESP (MWh)**	*Row 5 * (1 - Row 3)*	4,764,481
7			
8	**Current Adjusted Legacy ESP Rate ($/MWh)**	*Row 1 / Row 6*	76.62

Determination of Benchmark CB Auction Rate

		Source			
1	**Period Start**		**1/1/2013**	**6/1/2014**	**6/1/2015**
2	**Period End**	*Source*	**5/31/2014**	**5/31/2015**	**5/31/2016**
3					
4	**Forecasted Wholsale Auction Price [1] ($/MWh)**	*Exhibit TFM-2, p 1, Col (D)*	42.71	52.90	60.80
5					
6	**Average SSO Loss Factor**	*WP5.1, p 1, Col (L), Line 22*	1.04275	1.04275	1.04275
7					
8	**Gross Revenue Conversion Factor**	*WP11, p 1, Col (D), Line 21*	1.0072	1.0072	1.0072
9					
10	**Forecasted Retail Auction Price ($/MWh)**	*Row 4 * Row 6 * Row 8*	44.86	55.56	63.86

[1] These prices are the forecasted auction clearing prices most representative of market prices during the applicable delivery period. The June 2015 - May 2016 price is from the June 2015 - May 2018 delivery period because no one-year price was provided for this delivery period in Exhibit TFM-2. If a price is available for the one-year June 2015 - May 2016 period, that price would be used in the calculation of the switching tracker.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP) SECOND REVISED DIRECT TESTIMONY OF R. JEFFREY MALINAK

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY OF

R. JEFFREY MALINAK

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

I. INTRODUCTION

Q. Please state your name and address.

A. My name is R. Jeffrey Malinak. I reside at 10723 Normandie Farm Dr., Potomac, Maryland, 20854. I am currently a Managing Principal in the Washington, D.C. office of Analysis Group, Inc., a national economic and financial consulting services firm.

Q. What is the purpose of your testimony?

A. Under Ohio Law, a criterion for approval of an Electric Security Plan (ESP) is that it be "more favorable in the aggregate" than expected results from a Market Rate Offer (MRO). My testimony will focus on the question of whether the ESP proposed by The Dayton Power and Light Company (DP&L) meets this "more favorable in the aggregate" test.

Q. What is your educational and work background?

A. I have over 23 years of experience in the field of economic and financial consulting, in which I have provided microeconomic, finance and accounting consulting advice and other services to attorneys and companies in both litigation and non-litigation settings. My main areas of expertise are financial economics and valuation of corporations and other assets. I spent approximately seven years of my career at Putnam, Hayes & Bartlett, Inc. (PHB), an economic and financial consulting firm with large consulting practices in the energy industry and other regulated industries. While at PHB approximately half of my time was spent on litigation matters and regulatory proceedings, including rate cases, in the electric utility and energy sectors. My work on these matters included revenue requirements modeling; analysis of the economics of coal mining and transportation; analysis of the operations and economics of nuclear, coal, wood scrap and natural gas power plants; forecasting of load and related generation capacity requirements; assessment of the cost of capital for generation and for transmission and distribution (both electric and natural gas); calculation of the cost of compliance with environmental regulations; modeling and forecasting of emission allowance prices; and other topics. Since joining Analysis Group in the mid-1990s, I have continued to work on projects in the energy and environmental economics areas, including regulatory matters.

I hold a Masters in Business Administration in Finance and Accounting from the University of Texas at Austin and a B.A. in Social Sciences from Stanford University. My resume, which is included as Appendix A, provides more details on my background and prior experience.

Q. What has been the nature of your prior work as a testifying expert?

A. I have given arbitration testimony on economic damages issues and have been designated as an expert on several economic and financial topics on matters in which I provided expert reports. However, all of these matters settled before I gave trial testimony.

Q. How does your experience relate to your testimony in this proceeding?

A. I have substantial prior experience with analysis of economic and financial issues in the energy sector, and with the analysis of the economic impact of different rate regimes on a variety of stakeholders, including customers.

Q. Please summarize the conclusions that you have reached.

A. Based on my analysis, I conclude that the ESP filed by DP&L is more favorable in the aggregate than an MRO, primarily because the ESP provides for a faster transition to 100 percent market-based generation rates than would occur under an MRO. Indeed, this faster transition means that DP&L customers can expect to pay approximately $120 million less for their electricity through May 2018, based on the projections included in the ESP filing. In addition to this clear, quantifiable economic advantage, the ESP has several important advantages over the MRO that are more difficult to quantify. These include benefits from the faster transition to a competitive retail market, such as an improved ability to attract businesses to DP&L's service territory due to a more competitive, lower-cost market for retail electric services; administrative enhancements to promote retail shopping; and greater regulatory flexibility in the future relative to the statutory limitations set in place when an MRO is adopted. For these and other reasons discussed below, the ESP is more favorable in the aggregate for DP&L customers than an MRO.

II. ***<u>AN OVERVIEW OF THE "MORE FAVORABLE IN THE AGGREGATE" STATUTORY TEST</u>***

Q. Does DP&L's ESP have to meet certain requirements for approval by the Public Utilities Commission of Ohio (Commission)?

A. Yes. For the Commission to approve a utility company's ESP, the ESP must meet certain criteria that are specified in Section 4928.143 of the Ohio Revised Code. One of these criteria, specified in Section 4928.143 (C)(1), is

> "that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142 of the Revised Code."

My testimony provides an assessment of whether DP&L's ESP meets this criterion.

Q. Do prior Commission decisions provide guidance on how to interpret this criterion?

A. Yes. In prior rulings in which the Commission has decided that ESPs met this "more favorable in the aggregate" test, the Commission has taken a broad view of the expected impacts of ESPs relative to MROs to consider when performing this test, including (1) quantifiable differences in the prices to be charged to customers for electric generation service under each plan (Aggregate Price Test), (2) other quantifiable differences in customer charges (or, potentially, metrics of customer service); and (3) non-quantifiable differences.[1] This last category potentially includes a wide range of impacts, including expected short-run and long-run effects on price, service quality, reliability, and the range of product offerings. These differences also support broader effects on Ohio's economy through the impact of electric rates and services to business and industry within the state.

Reflecting this broad perspective, my assessment of the "more favorable in the aggregate" requirement considers multiple quantifiable and non-quantifiable characteristics of DP&L's proposed ESP versus those of a hypothetical alternative MRO. It is assumed that this hypothetical MRO would be similar to DP&L's ESP in every material respect, except that the ESP involves a faster transition to market generation rates and the ESP includes certain new programs aimed at enhancing retail markets.

[1] Public Utilities Commission of Ohio, Opinion and Order, Case No. 11-346-EL-SSO, August 8, 2012; Public Utilities Commission of Ohio, Opinion and Order, Case No. 12-1230-EL-SSO, July 18, 2012

Q. Can you explain how the "more favorable in the aggregate" test should be conducted?

A. Yes. The test should be an apples-to-apples comparison. By that I mean that the test should compare DP&L's as-filed ESP to a hypothetical MRO that DP&L would file on the same day.

Q. What elements have you considered in your comparison of the two alternative plans?

A. First, I perform an Aggregate Price Test, which compares rates and charges to customers that choose DP&L's Standard Service Offer (SSO) under the ESP as compared to the rates and charges that they would pay if they chose the SSO under an MRO. This test reflects both bypassable and non-bypassable charges. Second, I consider other differences between the ESP and an MRO which are meaningful but whose effects are difficult or impossible to quantify accurately. These include a range of effects, such as those arising from a faster transition of Ohio's electric markets to greater retail competition, enhancements to DP&L's administrative processes that promote customer shopping, and differences in regulatory flexibility between an ESP and an MRO.

III. *AGGREGATE PRICE TEST FOR DP&L'S ESP*

Q. What is the Aggregate Price Test?

A. The Aggregate Price Test is a comparison of the projected prices and charges to customers under DP&L's ESP as compared to an MRO. I perform this price test in

Exhibit RJM-1.[2] The Aggregate Price Test reflects a comparison of both bypassable and non-bypassable charges. Bypassable charges are charges that are paid only by customers that choose DP&L's Standard Service Offer (SSO). Thus, customers that choose to take generation service from a Competitive Retail Electric Service (CRES) provider "bypass" these charges. Non-bypassable charges are charges that are paid by all customers that receive distribution service from DP&L.

Q. Please describe the comparison of bypassable charges.

A. The Aggregate Price Test includes a comparison of bypassable charges under the ESP against bypassable charges under an MRO. Under both plans, bypassable rates will reflect a blend of two elements. The first is the current SSO rate subject to blending (current generation rate), which reflects DP&L's current SSO rate and adjustments proposed by DP&L. The second is the Competitive Bidding Plan (CBP) rate, which reflects the projected results of competitive bidding for the opportunity to supply DP&L's retail customers. Under each plan, DP&L's SSO rate will transition from the current generation rate to a CBP rate over time, although the transition occurs more quickly under the proposed ESP than the MRO. Specifically, the following table provides the blend rate percentages for current generation rates and CBP rate under each plan:

[2] The exhibits to this Second Revised version of my testimony have the same exhibit numbers (e.g., RJM-1), as the exhibits to my Original testimony, with each new exhibit designated as "Second Revised" in the upper left hand corner. However, for ease of reference, I will continue to refer to the exhibits in the text by their original number only. Moreover, this Second Revised version of my testimony relies on exhibits attached to Second Revised versions of testimony from other DP&L witnesses. Similarly, I will continue to refer to their exhibits by their original numbers only.

Plan	1/2013 – 5/2014	6/2014 – 5/2015	6/2015 – 5/2016	6/2016 – 5/2017	6/2017 – 5/2018
ESP					
Current Gen. Rate	90%	60%	30%	0%	0%
CBP Rate	10%	40%	70%	100%	100%
MRO					
Current Gen. Rate	90%	80%	70%	60%	50%
CBP Rate	10%	20%	30%	40%	50%

Blend rates under the ESP reflect the values in DP&L's proposed ESP, which starts in January 2013 and ends December 2017. For the MRO, blend rates are based on the requirements of Section 4928.142(D) of the Ohio Revised Code, which specifies maximum annual MRO blend rates that extend through May 2018. For comparison purposes, I assume both plans are for the period January 2013 through May 2018; starting in June 2018, under both plans, the SSO would reflect 0% current generation rates and 100% CBP rates. Consequently, the bypassable portion of SSO rates will be the same under both the MRO and ESP.

Q. What elements make up the current generation rate?

A. The current generation rate reflects all elements of the company's current SSO rates that are subject to blending with the CBP rate, including:

1. Base Generation Rates
2. FUEL Rider
3. Reliability Pricing Model (RPM) Rider

4. Transmission Cost Recovery Rider – Bypassable (TCRR-B)

As described in the testimony of Company Witness Seger-Lawson, these rates include elements that are fixed (Base Generation Rates) and elements that will depend on the true-ups of specific costs incurred by DP&L (FUEL Rider, RPM Rider, TCRR-B). In my analysis, I rely on projected current generation rates by class developed in Schedule 3 which is sponsored by Company Witness Seger-Lawson. Using these data, in Exhibit RJM-2, I calculate the weighted average projected current generation rates.

Q. What is the source of the CBP rates used in your analysis?

A. In my analysis, I rely on the proxy market rates supported by Company Witness Marrinan, with adjustments provided by Company Witness Rabb. These proxy market rates reflect the prices that would be charged by competitive suppliers for the opportunity to provide DP&L's distribution customers with full requirements generation service (FRS), which includes energy, capacity, transmission, ancillary services and other relevant charges needed to supply power to DP&L customers. The Company plans to procure these supplies through competitively bid auctions that are designed to secure supplies at competitive market rates. The rates used in the Aggregate Price Test also reflect adjustments for distribution losses, Commercial Activities Tax (CAT), and uncollectible expense. The calculation of these adjustments is sponsored by Company Witness Rabb, and shown in Schedule 5B.

Company Witness Marrinan's estimate of CBP rates is based on the results of recent FRS auctions in the nearby Ohio service territories of Duke Energy Ohio and First Energy (FE). To account for changes in markets over time and geographic and market differences, she makes various adjustments to these auction prices to arrive at CBP estimates for DP&L auctions. The adjustments account for (1) changes in expected future market prices that have occurred between the time of the Duke and FE auctions and the present, (2) differences in future capacity costs between service territories (from PJM's Reliability Pricing Model; and (3) differences in wholesale market costs between DP&L's service territory and the Duke and First Energy service territories.

Q. Have you reviewed the estimates of CBP rates developed by Company Witness Marrinan?

A. Yes, I have reviewed the estimates of CBP rates developed by Company Witness Marrinan and believe that they provide a reliable basis for the Aggregate Price Test. There are several reasons for this conclusion. First, the use of actual results from recent auctions for comparable products in nearby service territories provides a sound basis for a forecast of auction results under DP&L's ESP. The use of actual auction results accounts for the many factors affecting actual supply offers from auction participants that are difficult to capture using alternative approaches. Second, Company Witness Marrinan makes adjustments to these auction results to account for changes in market conditions over time, and geographic, market and product differences that could lead DP&L's auction results to differ from Duke and FE's results. These adjustments, which were described above, provide a reasonable means of accounting for known differences in circumstances between Duke and FE auctions and future auctions to serve DP&L customers.

Q. Based on your analysis, what impact is DP&L's ESP expected to have on the bypassable portion of customer charges compared to the MRO?

A. As shown in Exhibit RJM-1, I find that the proposed ESP will produce lower overall average blended SSO rates than the MRO. This difference in rates is $3.72 per MWh in 2014/15, $5.97 per MWh in 2015/16, $7.53 per MWh in 2016/17, and $5.44 per MWh in 2017/18. Assuming that the level of customer switching remains fixed, the ESP is expected to result in a reduction in aggregate charges to DP&L customers of $19.7 million in 2014/15, $31.6 million 2015/16, $39.9 million in 2016/17 and $28.8 million in 2017/18.

Q. Do you also consider non-bypassable customer charges?

A. Yes. The Aggregate Price Test explicitly considers one non-bypassable charge: the Service Stability Rider (SSR). I assume that the level of the Service Stability Rider (SSR) and the financial cost justification for it would be similar whether the Company filed an ESP or an MRO. Under both the proposed ESP and an MRO, the SSR non-bypassable charge would remain the same. Consequently, there is no difference in customer non-bypassable charges under the ESP compared to the MRO.

Q. Did you include the proposed switching tracker in the Aggregate Price Test?

A. No. As described by Company Witnesses Jackson and Seger-Lawson, the switching tracker is a non-bypassable charge designed to allow DP&L the opportunity to recover a portion of the cost of customer switching (from the SSO to service provided by a CRES) in excess of the current level of switching. The current level of switching is held fixed in the projections included in the ESP filing and, I assume, would also remain fixed under the hypothetical MRO. In addition, I assume that the switching tracker would be included in the hypothetical MRO as well as in the ESP, because DP&L would face financial risks from customer switching under either plan.

Under either plan, the switching tracker would work as a revenue true-up mechanism such that total aggregate customer charges would not be affected significantly by a higher switching level. At most, there would be a lag in payment of the relevant charges. Consequently, I do not explicitly consider the switching tracker when performing the Aggregate Price Test.

Q. Did you explicitly consider any of the other non-bypassable customer charges in the Aggregate Price Test?

A. No. DP&L has proposed other non-bypassable charges, such as the Transmission Cost Recovery Rider – Non-bypassable (TCRR-N) and the Reconciliation Rider (RR), that I do not explicitly address in my analysis. These charges largely reflect pass-through of various costs to customers. Further, like the SSR, these charges would be present in both the proposed ESP and hypothetical MRO, and consequently have no impact on the Aggregate Price Test.

Q. Can you explain why you state that DP&L would recover the SSR under either its ESP filing or under a hypothetical MRO?

A. As explained above, to conduct the "more favorable in the aggregate" test, the Commission should compare the ESP that DP&L filed to a hypothetical MRO that DP&L

would file on the same day. As explained in the testimony of Company Witness William Chambers, DP&L needs an SSR of $137.5 million to preserve its financial integrity; DP&L seeks approval of that charge under § 4928.143(B)(2)(d) of the ESP statute.

If DP&L had filed an MRO, then DP&L would face threats to its financial integrity that are similar to those described in Mr. Chambers' testimony. Like the ESP statute, the MRO statute permits the Commission to implement charges to preserve a utility's "financial integrity."[3] DP&L thus would have sought an SSR if it had filed for an MRO.

If this SSR is assumed to be the same magnitude as under the ESP, then all else equal DP&L's projected revenues, profits and financial integrity would be somewhat higher (due to higher SSO rates) under the MRO than under the ESP. However, the improvement in DP&L's projected financial condition would not be sufficient to eliminate the financial risks that DP&L is projected to experience in the out years, as determined by Company Witness Chambers. Therefore, it is reasonable to assume that DP&L would have sought the same SSR under an MRO as it is seeking under the ESP. Consequently, the SSR that DP&L seeks to recover in its ESP filing has no effect on the comparison to an MRO.

Nevertheless, if one were to assume that under an MRO DP&L would have requested an SSR that was just large enough so that total customer charges (and DP&L revenue) were the same as under the ESP, then the ESP and MRO would be equivalent under the Aggregate Price Test, but the ESP still would be more favorable in the aggregate than the MRO due to the non-quantifiable benefits of the ESP discussed later in my testimony.

[3] Ohio Rev. Code § 4928.142(D)(4).

Q. What do you conclude about the impact of DP&L's ESP on customer charges compared to the MRO?

A. As shown in Exhibit RJM-1, the proposed ESP is expected to produce lower charges to SSO customers than an MRO. These differences in average rates and total charges are the same as those for the bypassable portion of customer charges. Average rates will be lower under the ESP by $3.72 per MWh in 2014/15, $5.97 per MWh in 2015/16, $7.53 per MWh in 2016/17, and $5.44 per MWh in 2017/18. When aggregated across all customers, the ESP is expected to lower customer charges by $19.7 million in 2014/15, $31.6 million 2015/16, $39.9 million in 2016/17, and $28.8 million in 2017/18.

Q. Are there other quantifiable differences between the ESP and the MRO?

A. Yes. There are two differences. First, in addition to the rates and charges analyzed in Exhibit RJM-1, competitive retail enhancements that are a part of the ESP would require a one-time investment of $2.5 million.[4] This program will provide certain non-quantifiable benefits that I discuss below. Second, under an MRO, there would be no revenue adjustment associated with the Yankee Solar Facility. My Exhibit RJM-1 does not include any impact from the Yankee Solar Facility adjustment. I understand that the total capital cost of the Yankee Solar Facility was $3.3 million. Those two additional costs associated with the ESP thus would not affect my conclusion that the ESP is more favorable in the aggregate than the MRO.[5]

[4] Testimony of Dona Seger-Lawson.
[5] The Dayton Power and Light Company's Supplement to Its ESP Application, November 8, 2012, at Exhibit 4 Yankee Solar Property.

IV. OTHER, NON-QUANTIFIABLE CHARACTERISTICS OF THE PROPOSED ESP AND MRO

Q. Are there differences between the two plans not captured in the Aggregate Price Test that are difficult to quantify, but that are relevant to determining if the ESP is "more favorable in the aggregate"?

A. Yes. First, the faster transition to market-based rates under the ESP has certain benefits that are real, but difficult to quantify.

Under the ESP, DP&L customers will be fully transitioned to market rates by June 2016. In contrast, under the MRO, a full transition to market rates would not occur until June 2018. Moreover, a larger portion of customer rates will reflect market prices under the ESP in all years leading up to the date of full transition.

With this faster transition, DP&L's ESP will support the broader policy goals, such as a more favorable climate for business and more choices for consumers, that were envisioned when the General Assembly approved legislation to transition the state's customers to market-based pricing.[6]

In addition, it is important to note that the Commission has already approved ESPs for other Ohio electric utilities that result in faster transitions to market rates than would occur under an MRO.[7] By approving DP&L's ESP, the Commission can ensure that DP&L customers face comparable market conditions and have comparable opportunities to take advantage of more competitive retail market conditions.

[6] Ohio Legislative Service Commission, Final Analysis, Am. Sub. S. B. 3, July 6, 1999.
[7] Public Utilities Commission of Ohio, Opinion and Order, Case No. 11-346-EL-SSO, August 8, 2012; Public Utilities Commission of Ohio, Opinion and Order, Case No. 12-1230-EL-SSO, July 18, 2012.

In sum, the faster transition to greater competition under the ESP is expected to provide both short and long-run benefits to the state's customers and economy.

Q. Does DP&L's ESP provide other non-quantifiable benefits relative to an MRO?

A. Yes. Along with the faster transition to market rates, DP&L's ESP provides additional benefits that would not be experienced under an MRO. In particular:

1. Competitive retail enhancements funded through DP&L's ESP will facilitate competitive retail markets by reducing administrative barriers and transaction costs that potentially affect the opportunities for CRES providers to encourage customers to switch to competitive suppliers.
2. Ohio Revised Code Section 4928.142 requires that if an MRO is approved for an electric distribution utility, then it "shall not, nor ever shall be authorized or required by the commission to, file an application under section <u>4928.143</u> of the Revised Code." (emphasis in original) In contrast, no such prohibition appears in section 4928.143 of the Revised Code. Thus, DP&L's filing for and receiving approval of an ESP provides more regulatory flexibility in the future than if DP&L filed an MRO.

V. CONCLUSION

Q. Do you conclude that DP&L's ESP is "more favorable in the aggregate" than an MRO?

A. Yes. The facts support that conclusion. DP&L's ESP results in lower rates and charges to DP&L customers taking SSO service than an MRO. In addition, the ESP provides non-quantifiable benefits that exceed those under an MRO. Consequently, I conclude that DP&L's ESP is "more favorable in the aggregate" than an MRO.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

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Mr. Malinak is an expert in financial economics with particular expertise in damages estimation, applied finance theory, and business and asset valuation. He has directed a number of class action securities fraud matters and several securities and commodity market manipulation cases. Mr. Malinak also has considerable experience in financial institutions and risk management, having been heavily involved in the Winstar savings and loan litigations, and having also completed a major project on the risk of Fannie Mae. He has directed litigation projects in numerous industries on issues related to intellectual property, breach of contract, securities, regulatory economics, asset valuation, insurance, accounting, taxation and antitrust, and has provided deposition and arbitration testimony on economic damages issues. Mr. Malinak also has acted as a management consultant to clients in the energy, environmental and health care industries, and as an economic valuation and business strategy consultant to clients with new technology, intellectual property and intangible assets. Prior to joining Analysis Group, he was a Principal at Putnam, Hayes & Bartlett, Inc.

EDUCATION

M.B.A. (Finance and Accounting), University of Texas Graduate School of Business (Austin, Texas)

B.A., Social Sciences, *with Distinction*, Stanford University (Palo Alto, California)

PROFESSIONAL EXPERIENCE

2000-	*Managing Principal,* Analysis Group, Inc. (Washington, D.C.). Financial and economic analysis and testimony related to complex securities, finance, accounting, antitrust and general business litigation. Financial and economic consulting related to public policy issues and business and other asset valuation.
1997-1999	*Vice President,* Analysis Group, Inc. (Washington, D.C.).
1996-1997	*Vice-President and Secretary/Treasurer*, Malinak Medical Products, Inc., (Phoenix, Arizona), a wholesale medical supplies and service company.
1994-1996	*Principal,* Putnam, Hayes & Bartlett, Inc. (Washington, D.C.).
1988-1993	*Associate*, Putnam, Hayes & Bartlett, Inc. (Washington, D.C.).
1986-1987	*Staff Consultant*, Peterson & Co. (Houston, Texas).

SELECTED REPRESENTATIVE CONSULTING ENGAGEMENTS

General Business Litigation

CIRCUIT COURT FOR THE CITY OF ALEXANDRIA, VIRIGNIA
General Motors Acceptance Corporation (GMAC) v. Field Auto City, Inc.
Expert report (co-authored) regarding the damages sustained by a car dealership due to the alleged improper withdrawal of floor plan financing by GMAC.

U.S. BANKRUPTCY COURT, SOUTHERN DISTRICT OF NEW YORK
In re: Genuity., et al., Debtors.
Analysis of asset purchase agreement and damages in this bankruptcy proceeding. Key issues included the cause of bankruptcy, the value of the enterprise and the economic and financial impact of the proposed restructuring agreement.

U.S. DISTRICT COURT, DISTRICT OF COLUMBIA
Philip L. Chabot, Jr. v. Brickfield, Burchette & Ritts, P.C. et al.
Expert report regarding the value of an equity interest in a "greenfield" steel company at various stages in the firm lifecycle, including the seed capital and start-up financing stages.

UNITED STATES COURT OF FEDERAL CLAIMS, WASHINGTON, D.C.
FDIC as Receiver for various Savings & Loan Institutions v. The United States
Overall project management and analysis of damages. Key issues included the appropriateness of various damages theories and the value of leverage in the regulated thrift industry.

AMERICAN ARBITRATION ASSOCIATION, NEW YORK
New Industries Co. (Sudan) Ltd. v. Pepsico, Inc.
Overall case management and analysis of damages in this breach of contract case involving the original Pepsi bottler in Sudan. Key issues included the appropriate methods for projecting lost profits and the valuation of the business of a soft drink bottler.

DISTRICT OF COLUMBIA AND DELAWARE CHANCERY COURTS
Robert Haft v. Herbert Haft and Dart Group
Analysis of the value of large holdings of common stock and options on the common stock of a number of public and private companies with a combined $1 billion plus in revenues. Key issues included assumptions to use in a discounted cash flow analysis (DCF), the valuation of employee stock options and the applicability of minority and marketability discounts to securities prices.

Antitrust

U.S. DISTRICT COURT, NORTHERN DISTRICT OF CALIFORNIA
Central Garden & Pet Company v. The Scotts Company and Pharmacia
Overall case management and analysis of antitrust damages. Key issues included the appropriate herbicide product market definition, the measurement of market power, and the effect of the trend towards "big box" retailers on herbicide manufacturers and distributors.

U.S. DISTRICT COURT, NORTHERN DISTRICT OF IOWA
Act, Inc. v. Sylvan Learning Systems
Overall case management and analysis of antitrust damages.

TEXAS STATE COURT, CORPUS CHRISTI
Independent Service Provider v. IBM
Damages and antitrust analyses prepared on behalf of IBM. Key issues included definition of relevant markets, calculation of the defendant's market share, calculation of antitrust and business disparagement damages and valuation of settlement options.

U.S. DISTRICT COURT, FLORIDA
Thermo Electron & Rolls Royce, Inc. v. Florida Power & Light
Analysis of damages due to alleged anticompetitive acts by an electric utility. Key issues included forecasting of fuel prices, business decision-making procedures, profitability of cogeneration facilities and the appropriate cost of capital to use in evaluating investments in electricity generation facilities.

TEXAS COURT
ETSI Pipeline Project, et al. v. Burlington Northern, et al.
Assistance to counsel in rebutting opposing expert's lost profits damages claim. Key issues included the appropriate measure of lost profits and the appropriate discount and interest rates to apply in valuing the lost profits stream.

Securities and Commodity Market Litigation

U.S. DISTRICT COURT FOR THE SOUTHERN DISTRICT OF TEXAS, HOUSTON DIVISION
United States of America v. Mark David Radley, et al.
Overall case management and analysis of natural gas liquids markets, propane price movements, market microstructure issues and allegations regarding market power and price manipulation. Key issues included the size and definition of the relevant market, the appropriate measurement of market power in the context of futures/forward contract markets, and appropriate methods for analyzing trading behavior and specific claims of price manipulation.

U.S. DISTRICT COURT FOR THE DISTRICT OF MARYLAND, BALTIMORE DIVISION
United States Securities and Exchange Commission v. Agora, Inc., Pirate Investor, LLC and Frank Porter Stansberry
Overall case management and analysis of the materiality to investors of certain information regarding a nuclear fuel processing firm contained in an investor newsletter. Key issues included the effect of public information releases on the firm's stock price.

U.S. DISTRICT COURT, DISTRICT OF MASSACHUSETTS
Class v. Life Sciences Company 1
Expert report on damages and participation in a mediation hearing. The analysis addressed the value of the common stock and other securities of a Life Sciences company at different times and under different assumptions.

U.S. DISTRICT COURT, DISTRICT OF MASSACHUSETTS
Class v. Life Sciences Company 2
Expert report on the alleged damages of the lead plaintiff, which was a hedge fund, and analysis of alleged class-wide damages. The expert report addressed the economic impact on the lead plaintiff of the simultaneous increase in value of a short position in the Life Sciences' firm's common stock and the decrease in value of the plaintiff's convertible bond position.

U.S. DISTRICT COURT FOR THE DISTRICT OF MASSACHUSETTS
In Re: Xcelera.com Securities Litigation
Overall case management and analysis of the efficiency of the market for the equity securities of an internet-related firm for class certification purposes in a 10b-5 matter. Key issues included the existence of limits to arbitrage (e.g., short sales constraints) and the extent of participation by traders who were trading based on non-fundamental economic criteria during the class period.

U.S. DISTRICT COURT FOR THE DISTRICT OF IDAHO
Muzinich & Co., Inc. et al. v. Raytheon Company, et al.
Overall case management and analysis of the efficiency of the market for the unregistered 144A bonds of a construction firm. Key issues included the existence of appropriate analyst coverage, the amount of trading volume, the nature of the reaction of the bond prices to new information and the size of the bid-ask spread.

COURT OF COMMON PLEAS, PHILADELPHIA COUNTY
Plaintiff Class v. Sun Company, Inc.
Overall case management and analysis of trading in Sun common stock related to allegations that a preferred stock redemption rate calculation was affected by stock price manipulation.

U.S. DISTRICT COURT, EASTERN DISTRICT OF PENNSYLVANIA
Plaintiff Class v. Centocor, Inc.
Analysis of alleged securities fraud damages and other economic issues in a 10b-5 matter involving allegations surrounding the announcement of the outcome of joint venture negotiations. Key issues included the measurement of abnormal stock returns in the presence of extreme volatility and the analysis of damages, if any, to various investor sub-classes, including day traders and short-sellers.

U.S. DISTRICT COURT, NORTHERN DISTRICT OF ILLINOIS
Plaintiff Class v. Kemper Mutual Funds
Analysis regarding distribution of returns on over 130,000 S&P500 futures transactions in investigation of improper trading and self-dealing by the fund manager in class-action involving investors in two public equity mutual funds. Key issues included definition of hedging strategies, trade matching methods and appropriate statistical methods.

TEXAS STATE COURT, BEAUMONT
Plaintiff Class v. Paine Webber
Analysis of the sale prices for limited partnership units. Key issues included the amount of damages sustained by two different investor classes, the average settlement amounts in securities fraud matters, and the value of a company after a roll-up reorganization into an equity financed company.

Tax-Related Litigation

AMERICAN ARBITRATION ASSOCIATION, CHICAGO, ILLINOIS
Tax Payer v. Tax Transaction Participant
Overall case management and analysis of finance and valuation issues. Work included assessing the economic substance of a transaction involving the purchase of emerging market distressed consumer and trade debt, determining the value of this distressed debt and performing "forensic accounting" analysis.

U.S. COURT OF FEDERAL CLAIMS
National Westminster Bank, PLC. v. United States
Overall case management and analysis of accounting issues. Work included the reconstruction of the financial statements of the U.S. branches of a foreign bank, based on accounting and other information that was incomplete and, in many cases, over 20 years old.

U.S. DISTRICT COURT, DISTRICT OF MARYLAND, BALTIMORE DIVISION
Black and Decker, Inc. v. United States
Overall case management and analysis of economic issues. Key issues included the economic substance and business purpose of a transaction involving the formation of a special purpose entity and the payoff structures of different financial instruments.

U.S. DISTRICT COURT, SOUTHERN DISTRICT OF W. VIRGINIA
Flat Top Insurance Agency v. United States
Expert report regarding the economic life and value of insurance renewal intangible assets to be used for tax depreciation purposes.

U.S. DISTRICT COURT, EASTERN DISTRICT OF VA, RICHMOND DIV.
Trigon Insurance Company vs. United States of America
Overall case management and analysis of economic issues in a tax refund case involving a customer base as an intangible asset.

<u>Environmental Insurance Litigation</u>

SUPERIOR COURT OF THE STATE OF WASHINGTON, KING COUNTY
Alcoa Inc., and Northwest Alloys, Inc., v. Accident and Casualty Insurance Company, et al.
Analysis of the history of environmental regulation of various pollutants to determine the extent of government and industry knowledge regarding those pollutants at various policy dates. Analysis of economic damages due to environmental contamination.

ENVIRONMENTAL INSURANCE SETTLEMENT MATTER
General Electric v. Environmental Insurance Firms
Analysis of the value of future environmental remediation cost liabilities for settlement purposes, including the determination of the appropriate discount and inflation rates to use in valuing projected environmental remediation costs.

<u>Intellectual Property Litigation</u>

U.S. DISTRICT COURT, DISTRICT OF CONNECTICUT
Joint Medical Products Corporation v. Depuy, Inc., et al.
Analysis of patent damages. Key issues: the factors driving the buying decision in the hip implant market, fixed versus variable costs and relevant licensing rates for comparable products.

U.S. DISTRICT COURT, EASTERN DISTRICT OF VIRGINIA
Wang Laboratories, Inc. v. America Online, Inc. and Netscape Communications Corp.
Valuation of patented on-line services software interface features. Key issue: the economic value of customer retention.

U.S. DISTRICT COURT, EASTERN DISTRICT OF PENNSYLVANIA
BTG USA, Inc. v. Magellan Corp. / BTG v. Trimble Navigation
Patent damages: analysis of prejudgment interest, reasonable royalty, value of inventory on hand, preparation and investments made and business commenced (as of patent reissuance) involving a patent directed to secret or secure communications technology employed in global positioning systems products.

U.S. DISTRICT COURT, DISTRICT OF MASSACHUSETTS
Polaroid v. Kodak
Patent damages: analysis and preparation of trial exhibits in support of academic witness's discount and interest rate testimony. Analysis of fixed and variable costs for use in lost profits study involving an instant photography technology patent.

Prospective Intellectual Property Consulting and Valuation

Internet Security/Privacy Technology
Valuation of a patent-pending technology for enhancing the security and privacy of web-based transactions and interactions.

Smartcard Technology for GSM Wireless Phones
Valuation of a portfolio of patents in relation to their potential use in GSM wireless phones.

Automotive Industry Patent Portfolio
Preparation of a preliminary report supporting the potential value of an international portfolio of product patents in the automotive industry. Identification of industry players, description of market structure, profitability analysis of potential licensees and estimation of potential royalty payments.

Biotechnology Patent
Preparation of materials supporting the potential value of a basic process patent in the biotechnology industry. Identification of industry players, description of market structure, and profitability analysis of potential licensees.

Medical Diagnostic Test Patent
Identification of industry players, description of market structure, evaluation of alternative technologies and profitability analysis of potential licensees.

Wireless Telecommunications Patent
Preparation of a report on the potential value of a basic process patent in the wireless telecommunications industry. Identification of industry players, description of market structure, evaluation of alternative technologies and profitability analysis of potential licensees.

Management Consulting and Valuation Projects

CLIENT: FANNIE MAE
Overall responsibility for assisting in the preparation of a white paper appearing on Fannie Mae's website, including analysis of the financial risk of Fannie Mae. Key issues included the appropriate model to use in evaluating the risk of a large regulated mortgage banking and guarantee business with a sophisticated hedging operation using derivatives.

CLIENT: ENVIRONMENTAL INSURANCE FIRM

Expert report regarding the appropriate discount and inflation rates to use in calculating the present value of projected environmental remediation costs. Participation in settlement meetings.

CLIENT: HOSPITAL MANAGEMENT

Analysis of the value of a hospital in connection with a proposed hospital merger transaction. Key issues included the appropriate measure of hospital profits, the cost of capital to use in valuing those profits and the impact of market forces (e.g., managed care) on the hospital's future revenues.

CLIENT: MAJOR FEDERAL GOVERNMENT AGENCY

Review of the decision making methods and data regarding a large government energy project. Key issues included the best quantitative methods to use to support the government's decision, the appropriate discount rates to use in valuing different projects and the option value of flexibility when projecting the cost of private and government mega-projects.

CLIENT: WOOD FLOORING MANUFACTURER

Preparation of an economic feasibility study for the installation of a cogeneration facility by a basketball court flooring manufacturer. Effort included extensive research into the cost of constructing a facility and the projected cost of power in the Upper Peninsula of Michigan.

Regulatory Consulting

SOUTH CAROLINA PUBLIC SERVICE COMMISSION, DOCKET NO. 2005-113-G (Application for Increase in Gas Rates and Charges)

Overall project management and analysis of the appropriate cost of capital for a natural gas distribution system.

U.S. ENVIRONMENTAL PROTECTION AGENCY, WASHINGTON, D.C.
Energy Industry

Expert affidavit and declaration in a Freedom of Information Act matter regarding the value of information contained in confidential business documents.

U.S. EPA AND/OR PUBLIC INTEREST GROUPS V. VARIOUS DEFENDANT FIRMS
Various Industries

Analysis of the present value of pollution control costs allegedly avoided due to non-compliance with Clean Water Act regulations. Work included review and critique of the EPA's "BEN" financial model for calculating the economic benefit of noncompliance with Clean Water Act regulations.

DEPOSITION AND TRIAL TESTIMONY

U.S. DISTRICT COURT, MIDDLE DISTRICT OF NORTH CAROLINA, DURHAM DIV.
Humana Military Healthcare Services, Inc., v. Blue Cross and Blue Shield of North Carolina, et al.

Expert report and deposition testimony regarding the amount of trade secret damages in the context of a large government managed care contract procurement.

AMERICAN ARBITRATION ASSOCIATION (BOSTON OFFICE)
Pragmatech Software v. Silknet Software, Inc.

Expert report and testimony at an arbitration hearing regarding the proper measure of damages in a breach of contract case involving alleged improper use of intellectual property / confidential information.

PUBLICATIONS

"Estimating the Cost of Capital," Litigation Services Handbook, The Role of the Financial Expert, Chapter 7 (pp. 7.1-7.22), Fourth Edition (2007) (co-authored with G. Jetley and L. Stamm).

SPEECHES/COURSES

"First Mover Advantages and e-Competition: Sustaining Superior Profitability in e-Commerce," presented as part of a panel titled, "Effective Use of Expert Witnesses in e-Commerce Antitrust Litigation," at a regional meeting of the antitrust litigation section of the American Bar Association, February 2001.

"Savings & Loan Financial Modeling Issues," presentation to the Receivership Goodwill Section of the Federal Deposit Insurance Corporation, October 2000 (confidential).

"Internet Patents -- Monetary Remedies" (with John C. Jarosz), American Intellectual Property Law Association (22nd Mid-Winter Institute titled, "IP Law in Cyberspace"), February 1999.

NEWSLETTER ARTICLES

"Damage Awards – Royalty Rates versus Profit Rates," IP Litigator, November/December 2000 (Volume 6, Number 6).

"Presenting Economic Expert Testimony to a Jury: Five Golden Rules," antitrust litigation newsletter.

Second Revised

Exhibit RJM-1

The Dayton Power and Light Company

Case No. 12-426-EL-SSO

Aggregate Price Test: ESP versus MRO

Line	MRO and ESP Rates and Revenues	1/2013 - 5/2014	6/2014 - 5/2015	6/2015 - 5/2016	6/2016 - 5/2017	6/2017 - 5/2018	Total or Average	Source / Calculation
1	Bypassable Generation Rates ($/MWh)							
2	Current Generation Rate	$ 76.62	$ 76.62	$ 76.62	$ 76.62	$ 76.62	$ 76.62	Exhibit RJM-2
3	Forecasted CBP Auction Rates	$ 44.86	$ 58.01	$ 61.70	$ 64.07	$ 65.75	$ 58.88	Rabb, Schedule 5B, *Line 4*
4								
5	CBP Rate Blending Schedule (%)							
6	MRO	10.0%	20.0%	30.0%	40.0%	50.0%		Ohio Revised Code Section 4928.143
7	ESP	10.0%	40.0%	70.0%	100.0%	100.0%		Seger-Lawson, Schedule 5
8								
9	Blended SSO Rate ($/MWh)							
10	MRO	$ 73.45	$ 72.90	$ 72.15	$ 71.60	$ 71.18	$ 72.26	Line(2)*(1-Line(6)) + Line(3)*Line(6)
11	ESP	$ 73.45	$ 69.18	$ 66.18	$ 64.07	$ 65.75	$ 67.72	Line(2)*(1-Line(7)) + Line(3)*Line(7)
12	Difference in Bypassable Rates	$ -	$ (3.72)	$ (5.97)	$ (7.53)	$ (5.44)	$ (4.53)	Line(11) - Line(10)
13								
14	Total Bypassable Revenues ($Millions)							
15	MRO	$ 550.01	$ 385.92	$ 381.93	$ 379.04	$ 376.84	$ 2,073.74	Line(10)*Line(33)
16	ESP	$ 550.01	$ 366.21	$ 350.34	$ 339.16	$ 348.05	$ 1,953.76	Line(11)*Line(33)
17	Difference in Bypassable Revenues	$ -	$ (19.71)	$ (31.59)	$ (39.88)	$ (28.79)	$ (119.98)	Line(16) - Line(15)
18								
19								
20	Non-Bypassable Revenues ($Millions)							
21	MRO	$ 137.50	$ 137.50	$ 137.50	$ 137.50	$ 137.50	$ 690.00	Jackson, Exhibit CLJ-2
22	ESP	$ 137.50	$ 137.50	$ 137.50	$ 137.50	$ 137.50	$ 690.00	Jackson, Exhibit CLJ-2
23	Difference in Non-Bypassable Revenues	$ -	$ -	$ -	$ -	$ -	$ -	Line(22) - Line(21)
24								
25	ESP versus MRO Price Test ($Millions)							
26	Difference in Bypassable Revenues	$ -	$ (19.71)	$ (31.59)	$ (39.88)	$ (28.79)	$ (119.98)	Line(17)
27	Difference in Non-Bypassable Revenues	$ -	$ -	$ -	$ -	$ -	$ -	Line(23)
28	**Total Change in Revenues**	**$ -**	**$ (19.71)**	**$ (31.59)**	**$ (39.88)**	**$ (28.79)**	**$ (119.98)**	Line(26) + Line(27)
29								
30	**Load and Switching Assumptions**							
31								
32	Switching	61.5%	61.7%	61.7%	61.7%	61.7%		1 - Line(33) / Line(34)
33	DP&L SSO Load (TWh)	7.49	5.29	5.29	5.29	5.29		Seger-Lawson, WP-8
34	Total Load (TWh)	19.44	13.82	13.82	13.82	13.82		Seger-Lawson, WP-8

Note: The Aggregate Price Test value that comes from this spreadsheet does not include any impact from the Yankee Solar Facility adjustment

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Calculation of Average Current Generation Rate

Line	Monthly Charges Source	SSO Billing Determinants Seger-Lawson Schedule 8	SSO Private Outdoor Lighting kWh Seger-Lawson WP-8	TCRR-B Seger-Lawson Schedule 3	Base Generation Seger-Lawson Schedule 3	PJM RPM Rider Seger-Lawson Schedule 3	FUEL Rider Seger-Lawson Schedule 3	Total Rate = E+F+G+H
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Residential**							
2	Energy Charge							
3	0-750 kWh	1,731,167,208		$0.0032334	$0.0534600	$0.0006265	$0.0291455	$0.0864654
4	Over 750 kWh	806,878,296		$0.0032334	$0.0399800	$0.0006265	$0.0291455	$0.0729854
5								
6	**Residential Heating**							
7	Energy Charge							
8	0-750 kWh	612,029,320		$0.0032334	$0.0534600	$0.0006265	$0.0291455	$0.0864654
9	Over 750 kWh (S)	145,162,768		$0.0032334	$0.0399800	$0.0006265	$0.0291455	$0.0729854
10	Over 750 kWh (W)	415,139,303		$0.0032334	$0.0160500	$0.0006265	$0.0291455	$0.0490554
11								
12	**GS Secondary**							
13	Billed Demand - Over 5.0 kW	2,646,142		$0.2371739	$8.9813100	$0.2027130	$0.0000000	$9.4211969
14	Energy Charge							
15	0-1500 kWh	223,945,466		$0.0090331	$0.0555600	$0.0000000	$0.0291455	$0.0937386
16	1501 - 125,000 kWh	657,027,768		$0.0000000	$0.0134000	$0.0000000	$0.0291455	$0.0425455
17	Over 125,000 kWh	59,877,349		$0.0000000	$0.0083700	$0.0000000	$0.0291455	$0.0375155
18								
19	**GS Primary**							
20	Billed Demand - All kW	358,087		$0.3356282	$11.0779900	$0.2320861	$0.0000000	$11.6457043
21	Reactive Demand - All kVar	176,938		$0.0000000				$0.0000000
22	Energy Charge - All kWh	161,957,197		$0.0023860	$0.0067800	$0.0000000	$0.0283228	$0.0374888
23								
24	**GS Primary-Substation**							
25	Billed Demand - All kW	6,492		$0.3356282	$11.7115700	$0.2320861	$0.0000000	$12.2792843
26	Reactive Demand - All kVar	5,010		$0.0000000				$0.0000000
27	Energy Charge - All kWh	2,680,740		$0.0023860	$0.0055000	$0.0000000	$0.0280029	$0.0358889
28								
29	**GS High Voltage**							
30	Billed Demand - All kW	757,712		$0.3356282	$11.4391100	$0.2320861	$0.0000000	$12.0068243
31	Reactive Demand - All kVar	352,896		$0.0000000				$0.0000000
32	Energy Charge - All kWh	412,068,944		$0.0023860	$0.0052200	$0.0000000	$0.0280029	$0.0356089
33								
34	**Private Outdoor Lighting**							
35	Energy Charge - per lamp							
36	9500 Lumens High Pressure Sodium	7,024	273,951	$0.1070277	$0.4559294	$0.0000000	$1.1366745	$1.6996316
37	28000 Lumens High Pressure Sodium	3,047	292,531	$0.2634528	$0.8379740	$0.0000000	$2.7979680	$3.8993948
38	7000 Lumens Mercury	192,633	14,447,480	$0.2058225	$0.8767900	$0.0000000	$2.1859125	$3.2685250
39	21000 Lumens Mercury	34,055	5,244,529	$0.4226222	$1.3442400	$0.0000000	$4.4884070	$6.2552692
40	2500 Lumens Incandescent	57	3,623	$0.1756352	$1.6467400	$0.0000000	$1.8653120	$3.6876872
41	7000 Lumens Fluorescent	98	6,484	$0.1811238	$2.7979200	$0.0000000	$1.9236030	$4.9026468
42	4000 Lumens PT Mercury	7,130	306,595	$0.1180049	$5.6956600	$0.0000000	$1.2532565	$7.0669214
43								
44	**School Rate**							
45	Energy Charge - All kWh	979,446		$0.0032942	$0.0459900	$0.0004356	$0.0291455	$0.0788653
46								
47	**Street Lighting**							
48	Energy Charge - All kWh	44,379,153		$0.0027660	$0.0101900	$0.0000000	$0.0291455	$0.0421015
49								
50	**Total Revenues**			16,582,789	232,239,410	3,121,853	153,685,296	405,629,349
51	**Total kWh**	5,293,868,152						
52	**Average Rate ($ / MWh)**							$76.62

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY
OF TERESA F. MARRINAN

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED TESTIMONY OF
TERESA F. MARRINAN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION

Q: Please state your name and business address.

A. My name is Teresa F. Marrinan. My business address is 1065 Woodman Drive, Dayton, OH 45432.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as Senior Vice President, Competitive Market Services.

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

A. I assumed my present position in January 2012. Prior to that, I held the position of Senior Vice President, Business Planning and Development. I have also served as the Company's risk manager and held prior positions of Senior Vice President, Commercial Operations; Managing Director, Portfolio Management; and several other managerial and technical positions within the Company's wholesale and retail business units.

Q. What are your responsibilities in your current position?

A. In my current position, I am responsible for executing the Company's commercial operations and portfolio management strategies, including the unregulated retail electricity and street lighting businesses; short- and long-term coal, power, emission allowances, and natural gas purchasing and trading activities; the 24-hour real time dispatch of the Company's 3,700 megawatt power generation fleet; the scheduling and physical delivery of the Company's coal and other commodities and the Company's participation within the PJM Regional Transmission Organization market. I direct the

Company's strategic market assessment efforts and business and portfolio analytics capabilities. I am responsible for recommending investment alternatives and capital allocation decisions that improve the Company's ability to meet its growth and profitability objectives consistent with an acceptable overall corporate financial risk profile.

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

A. I received a Bachelor of Science in Business Administration degree in December 1983 from the University of Dayton and a Master of Business Administration in June 1993 from Xavier University. I have been employed by DP&L since April 1984.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission")?

A. Yes. I have sponsored testimony before the PUCO in several occasions during my years with the Company. Most recently I provided two pieces of testimony supporting DP&L's current Electric Security Plan (ESP) in Case Nos. 08-1094-EL-SSO, *et al.*

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the items that will be included in the Fuel Rider component of DP&L's proposed Standard Service Offer (SSO) rates and the mechanism that will be used to calculate the Fuel Rider during the term of the proposed ESP. In addition, my testimony supports the proxy market-based auction prices for the Competitive Bid Process (CBP) used in the projections of financial and rate impacts of the proposed ESP supported by other DP&L witnesses.

II. FUEL RIDER

Q: Please describe DP&L's proposed Fuel Rider.

A. DP&L proposes a bypassable Fuel Rider to be effective January 1, 2013 for the recovery of fuel costs, purchased power costs, and emission allowance costs. The Fuel Rider will be based on a system average cost methodology with the objective of providing the least overall cost energy supply for DP&L customers.

Q. What are the key components that will be included in DP&L's Fuel Rider?

A. A summary of the key components is as follows:

Fuel Costs: The costs of fuel commodity, fuel transportation and fuel handling, used for the generation of electricity by DP&L-owned resources will be included in the calculation of the system average cost. The applicable fuel costs will be components found in Federal Energy Regulatory Commission (FERC) Accounts 501, 456, and 547. The majority of such fuel costs are recorded in FERC Account 501. Gains and losses on fuel sales are recorded in FERC Account 456, netted with FERC Account 501 and are included in the Fuel Rider. FERC Account 547 includes the costs of fuel used in gas and diesel peaking units. The portion of any recorded costs for biomass and similar fuels that is higher than the equivalent cost of coal will be excluded from the system average cost calculations and recovered through DP&L's Alternative Energy Rider. The portion of these costs up to the equivalent cost of fuel will be included in the system average cost calculations for recovery through the Fuel Rider. This methodology is consistent with the proceedings and the Opinion and Order in the Matter of the Application of The Dayton Power and Light Company to establish a Fuel Rider, PUCO Case No. 09-1012-EL-FAC.

Purchased Power Costs: Purchased power costs will be included in the calculation of the system average cost when DP&L-owned resources are not sufficient to meet the SSO load requirement that is not served by the CBP. The applicable purchased power costs will be components of FERC Account 555 and any related gains or losses are recorded in FERC Accounts 421 and 426.

Emission Allowances: The costs of emissions allowances used for the generation of electricity by DP&L-owned resources will be included in the calculation of the system average cost. FERC Account 509 records the costs of emission allowances. Currently this account includes sulfur dioxide and nitrogen oxides, both seasonal and annual, emissions allowance costs. Future legislation may add other types of allowance costs that would also be recorded in this account for recovery. This approach is consistent with the proceedings in the Matter of the Application of The Dayton Power and Light Company to establish a Fuel Rider, PUCO Case No. 09-1012-EL-FAC. Gains and losses on the sale of emission allowances are recorded in FERC Accounts 411.8 and 411.9. This approach is consistent with the proceedings and Opinion and Order in the Matter of the Application of The Dayton Power and Light Company to establish a Fuel Rider, PUCO Case No. 09-1012-EL-FAC. FERC Account 506 records the cost of emission fees.

Q: Please describe the method the Company will use to calculate the Fuel Rider.

A: The Fuel Rider will be calculated using a DP&L system average cost method.

Q: What is the definition of the "system" for determining the system average cost?

A: The DP&L energy supply system, for purposes of the proposed Fuel Rider, includes DP&L-owned energy supply resources and purchased power.

Q: How is the system average cost calculated?

A: The Company will calculate its system average cost by including and adding up all of the components described above for the DP&L energy supply system during the applicable period (e.g., monthly). The system average cost is based on the cost of all supply and it is not dependent on the load of any affiliate or of the utility. These costs will then be divided by the total megawatt hours (MWh) of power from the DP&L energy supply system for the same period. The result is a system average cost of energy supply in $/MWh or cents per kilowatt hour that will then be the basis for the Fuel Rider component for DP&L's SSO customers.

Q: How will the system average cost be converted into the Fuel Rider Rate?

A: The rate will be forecasted and filed on a seasonal quarterly (averaged over the three months in the quarter) basis, consistent with the approach used for the Fuel Rider component of DP&L's current SSO rates. The quarterly forecast of the system average cost will be determined using projected DP&L energy supply system costs (in dollars) and output (in MWh) for the upcoming seasonal quarter, which will then become the basis for the Fuel Rider rate for the upcoming seasonal quarter. The specific approach for filing the Fuel Rider rate, as well as reconciliation and true-up of any differences between the Fuel Rider rate and recorded system average costs, is discussed in Company Witness Nathan Parke's testimony.

Q: Why is the system average cost method appropriate?

A: The system average cost method is appropriate for several reasons. First, it improves operational efficiency because it is logical, simple and straightforward for DP&L to administer and for the Commission's staff and outside experts to understand and audit. The system average cost method also aligns incentives between DP&L and its customers by assigning the same system average cost for all DP&L customers. The system average cost method provides DP&L with clear incentives to manage its energy supply portfolio in order to achieve the least overall cost of energy supply for SSO customers under the proposed ESP. Finally, the system average cost method is consistent with the proposed blending of CBP prices into SSO rates under the proposed ESP, and can be applied consistently and simply throughout the entire term of the proposed ESP.

III. AUCTION PRICE

Q: Did you develop proxy auction prices to permit DP&L to demonstrate how its current prices would be blended with DP&L's current rates?

A. Yes. To assist in preparing the projected retail rate impacts of the Company's ESP plan, I developed proxy auction prices throughout the duration of the ESP. These proxy auction prices were then used by Company Witness Emily Rabb (whose testimony has been adopted by Company Witness Dona Seger-Lawson) to demonstrate how the auction prices for the CBP will be assigned to tariff classes and then blended with DP&L's current rates. These proxy auction prices are derived from the actual auction results from recent First Energy (FE) and Duke Energy–Ohio (Duke) auctions, which were then adjusted to reflect an equivalent proxy market-based auction price for a CBP in the Dayton zone.

Q. Please explain the methodology that you used in developing these proxy market-based auction prices for the CBP.

A. By way of background, the SSO auction supply contract commonly used in Ohio creates a complex fixed-price full requirements product which transfers certain risks to the winning auction supplier. These risks include variables such as forward market price volatility, day ahead and real time Locational Marginal Pricing (LMP) price volatility, unknown correlations between fuel and power prices, customer energy usage variations, customer switching risks, capacity cost recovery risk, and ancillary services price risk. When a supplier decides to participate in an SSO supply auction, it assigns a value to these various risks and prices those risks into its estimate of the overall cost to serve the SSO load. Each supplier prices risks differently, based upon institutional beliefs, risk appetite and modeling techniques. These opinions will impact the price the suppliers will be willing to bid in the SSO supply auction. Since pricing methodologies employed by suppliers vary, DP&L looked to the results of actual supply auctions taking place in recent Duke and FE auctions to derive a reasonable publically-available indication of the market's assessment as to the value of these risk factors within Ohio.

Q. Did DP&L make adjustments to the Duke and FE auction results?

A. Yes. Starting with the winning prices in each SSO auction, DP&L removed known fixed-cost components and the locational energy price differences between the products being solicited in each auction, which left a cost to serve SSO auctions in Ohio at a common point which could be used in projecting auction clearing prices in a DP&L CBP. Specifically, for Ohio, this common pricing point is the PJM AEP-Dayton Hub. PJM Reliability Pricing Model (RPM) capacity prices are currently known through May 2016 delivery. This RPM capacity value was removed from the auction clearing price. The remaining price was translated to the common PJM AEP-Dayton Hub by removing the locational energy price difference to the Duke and FE load zones. Using publicly available average PJM day-ahead LMP price differences between the delivery load zone and AEP-Dayton Hub as a proxy, the locational difference was removed, leaving a common cost to supply SSO auctions in Ohio at AEP-Dayton Hub. This cost to supply SSO auctions is then divided by the forward AEP-Dayton prices for a wholesale block over an equivalent time frame and on the same day as the auctions. This calculation yielded a ratio between market projections and actual auction results. This ratio was then applied to future AEP-Dayton forward curves on August 30th 2012 to project proxy auction clearing prices.

Q. What were the results?

A. This methodology produced fairly consistent results with an average SSO Auction to AEP-Dayton Hub Scaling Factor (Scaling Factor) of 1.24 times the AD Hub wholesale block supply (WP-13.2).

Q. What does the average Scaling Factor represent?

A. This average Scaling Factor represents a projection of the cost market participants would impute for the cost above a flat block product to deliver supply under an SSO auction contract, factoring in the risks I described earlier.

Q. How did you apply the average Scaling Factor?

A. Using this average Scaling Factor, DP&L used the AEP-Dayton forward price curve from August 30th, 2012 for each of the auction periods and projected a cost to supply that the market would currently place on DP&L's auctions at AEP-Dayton hub. By including historical day-ahead LMP locational price differences to deliver to the Dayton load zone, actual and proxy PJM RPM capacity prices, a final proxy DP&L CBP auction clearing price was estimated.

Q. Does this calculation appear in any Exhibits that you are sponsoring?

A. Yes. A more detailed explanation is included in Exhibit TFM-2, and supported by Workpapers WP 13.1-13.5.

Q. Is that methodology reasonable?

A. Yes, the methodology is reasonable because it represents an unbiased measure of the market's view of the costs and risks of supplying SSO auction load in a CBP, based upon publically available information. A competitive supplier bidding in the CBP individually would make its own assessment of these costs and risks, choose one or more pricing methodologies to account for them, and adjust the bids it submits in the CBP based on its discretion. Any attempt to imply a particular set of assumptions and pricing methodology would be too subjective and speculative. The methodology DP&L has employed for purposes of determining projected proxy future auction clearing prices in the CBP for purposes of this filing looks to the results of the recent Duke and FE auctions, which are the confluence of all of the auction participants' assessments regarding pricing. Given that each auction has had multiple winning bidders, the projections DP&L used represent unbiased supplier views regarding the value of the various costs and risks of supplying SSO load, as reflected by the market's collective view in assessing these costs and risk premiums based on recent auction results.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
PUCO Form FE-R3
Summary of Existing Electric Generation Facilities for the System (as of 12/31/2010)

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

Witness Responsible: Teresa Marrinan

Line	Station Name & Location	Unit No.	Type of Units	Date of First On-Line Service	Expected Retirement Date	Generation Summer (MW)	Generation Winter (MW)	Environmental Protection Measures
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Commonly Owned**							
2		1	Coal - Steam	May-71		202 *	202 *	Electrostatic precipitators on all units, flue gas de-sulfurization systems on all units, selective catalytic reactors on a units, wastewater treatment, Unit 4 cooling tower, flue gas conditioning (sulfur trioxide and sodium bi-sulfate) on all units, low NO_x burners on all units.
3	J.M. Stuart, Aberdeen, Ohio	2		Oct-70	Unknown	202 *	202 *	
4		3		May-72		202 *	202 *	
5		4		Jun-74		202 *	202 *	
6		1-4	Oil - Diesel	Oct-69		3 *	3 *	
7	W.H. Zimmer, Moscow, Ohio	1	Coal - Steam	Mar-91	Unknown	365 *	365 *	See Duke Energy Ohio Response
8	W.C. Beckjord, New Richmond, Ohio	6	Coal - Steam	Jul-69	Unknown	207 *	210 *	See Duke Energy Ohio Response
9	Conesville, Conesville, Ohio	4	Coal - Steam	Jun-73	Unknown	129 *	129 *	See AEP / CSP Response
10	Miami Fort, North Bend, Ohio	7	Coal - Steam	May-75	Unknown	184 *	184 *	See Duke Energy Ohio Response
11		8		Feb-78		184 *	184 *	
12	East Bend, Rabbit Hash, Kentucky	2	Coal - Steam	Mar-81	Unknown	186 *	186 *	Not in Ohio
13	Killen, Wrightsville, Ohio	2	Coal - Steam	Jun-82	Unknown	402 *	402 *	Electrostatic precipitators, flue gas de-sulfurization system, selective catalytic reactors, wastewater treatment, cooling tower, flue gas conditioning (sodium bi-sulfate), low NO_x burners.
14		1	Combustion Turbine	Apr-82		12 *	16 *	
15	**Total Commonly Owned**					**2,480.0**	**2,487.0**	
16								
17	**Individually Owned**							
18		1	Coal - Steam	Jul-48		49.5	49.5	Hot gas electrostatic precipitators on all six boiler units, low sulfur coal, wastewater treatment, low NOx burners on Units 3-6
19		2		Mar-49		47.8	47.8	
20	O.H. Hutchings, Miamisburg, Ohio	3		Dec-50	Unknown	59.0	59.0	
21		4		Feb-51		61.9	61.9	
22		5		Nov-52		58.5	58.5	
23		6		Sep-53		57.0	57.0	
24		7	Gas - Oil	Nov-68		25.0	33.0	
25		1	Gas - Oil	Jul-69		19.5	22.0	Existing-oil spill control system
26		2	Combustion Turbine	Jul-69		19.5	22.0	
27		3		Jul-69		19.5	22.0	
28	Yankee Street, Centerville, Ohio	4		Nov-70	Unknown	11.0	11.0	
29		5		Nov-70		8.0	8.0	
30		6		Nov-70		12.0	12.0	
31		7		Nov-70		11.0	11.0	
32		Solar	Photovoltaic	Mar-10		1.1	1.1	
33	Monument, Dayton, Ohio	1-5	Oil - Diesel	Jun-68	Unknown	12.0	12.0	
34	Sidney, Sidney, Ohio	1-5	Oil - Diesel	Jul-68	Unknown	12.0	12.0	
35		1-4	Oil - Diesel	May-67		10.0	10.0	
36	F.M. Tait, Dayton, Ohio	1	Combustion Turbine	Jun-95	Unknown	88.0	100.0	Water injection on Units 1-3
37		2		Dec-96		89.0	102.0	
38		3		Dec-98		80.0	102.0	
39	**Total Individually Owned**					**751.3**	**813.8**	
40								
41	**Total - All Units**					**3,231.3**	**3,300.8**	
42								
43	* Dayton Power and Light's share of commonly owned units							

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Proxy DP&L Auction Results

Data: Proxy | TFM-2
Type of Filing: Revised |
Work Paper Reference No(s).: WP-13.1 | Witness Responsible: Teresa Marrinan

Line	Delivery Start Date	Delivery End Date	Proxy Auction Price for the Term ($/MWh)	Number of Tranches to be Auctioned
(A)	(B)	(C)	(D)	(E)
			WP-13.1, Page 4, Col (I)	WP-13.1, Page 4, Col (J)
1	1/1/2013	5/31/2014	$42.71	10
2	6/1/2014	5/31/2015	$52.90	10
3	6/1/2014	5/31/2016	$54.37	10
4	6/1/2014	5/31/2017	$56.83	20
5	6/1/2015	5/31/2018	$60.80	40
6	6/1/2016	5/31/2018	$63.28	40
7	6/1/2017	5/31/2018	$64.83	20

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Proxy DP&L Auction Results

Data: Proxy — TFM-2
Type of Filing: Revised — Page 2 of 2
Work Paper Reference No(s).: None — Witness Responsible: Teresa Marrinan

Line	Delivery Start Date	Delivery End Date	Proxy Auction Price for the Term ($/MWh)
(A)	(B)	(C)	(D) *
1	1/1/2013	5/31/2014	$42.71
2	6/1/2014	5/31/2015	$55.23
3	6/1/2015	5/31/2016	$58.75
4	6/1/2016	5/31/2017	$61.00
5	6/1/2017	5/31/2018	$62.60

* The Proxy Auction Price for each delivery date is calculated by weighting the auction price for each term shown on page 1 by the respective number of tranches for that term.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY
OF NATHAN C. PARKE

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED TESTIMONY OF
NATHAN C. PARKE

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nathan C. Parke. My business address is 1065 Woodman Drive Dayton, OH 45432.

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

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

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

A. I assumed my present position in November, 2010. Prior to that time, I held various positions in the Regulatory Operations division, including Supervisor and Rate Analyst. Prior to Regulatory Operations, I spent over five years as an analyst in the Power Production division of DP&L. During that time, I was involved in Operation & Maintenance and Capital spending plans, generation forecasting including modeling for the Corporate Plan, power plant evaluations, and overall performance reporting of the generation fleet.

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

A. In my current position, I have overall responsibility for designing, tracking, and ensuring cost recovery for several of DP&L's rate riders. I am involved in evaluating regulatory and legislative initiatives, and regulatory commission orders that affect the Company's rates and overall regulatory operations. I report to the Director of Regulatory Operations.

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

A. I received a Bachelor of Arts degree in Business Administration with a concentration in Management from Wilmington College in Wilmington, Ohio in 2002. I have been employed by DP&L since 2002.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission"), any other state commission or the Federal Energy Regulatory Commission ("FERC")?

A. Yes. I have sponsored testimony before the PUCO in the Company's Fuel Rider Cases No. 09-1012-EL-FAC and No. 11-5730-EL-FAC.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support and explain several tariff modifications including modifications to the methodology of setting the Alternative Energy Rider ("AER"), adjustments to the reconciliation of the Fuel Rider, the removal of Rate B on the Residential Heating Tariff, and the phase-out of the maximum charge provision. My testimony explains the development of a new Competitive Bid True-up Rider and the rate design for a new Service Stability Rider. I also support the Typical Bill Comparisons.

Q. What Schedules and Workpapers are you supporting?

A. I am supporting Schedule 2D, Schedule 7B, Schedule 7D, Tariff Sheet Nos. G26, G28, a new Tariff Sheet No. G29, a new Tariff Sheet No. G30, and Schedule 10. I also support Workpaper 7B, Workpaper 7B.1, Workpaper 7D.1, Workpaper 7D.2, Workpaper 8, Workpaper 8.2, and Appendix C.

III. RATES AND RIDERS

ALTERNATIVE ENERGY RIDER ("AER"):

Q. What modifications to its AER does the Company propose?

A. DP&L is proposing that, similar to all other true-up riders in this case, the AER will be reconciled and adjusted on a seasonal quarterly basis by filing one month in advance of the rate change. The rider will be subject to an annual audit by the PUCO or a third party as directed by the PUCO.

Q. Do you propose the AER rate be applied in the same manner as it is today?

A. Yes. The rider will be assessed to customers in the same manner it is today as an energy-based charge. The Company's outdoor lighting rates are listed as a per-lamp charge which is based on the same energy charge.

Q. Where is the Tariff located?

A. The Tariff can be found on Tariff Sheet No. G26.

Q. Are there any other changes to the AER?

A. Yes. DP&L is proposing that the AER contain a 3% cost cap provision that establishes a threshold to be consistent with Ohio Revised Code §4828.64(C)(3).

Q. How is the 3% AER threshold calculated?

A. The estimated Competitive Bid Process (CBP) auction result is used as the means of otherwise acquiring the electricity. The expected auction result in dollars per kilowatt hour ($/kWh) is $0.0427100; three percent of that figure is $0.0012813.

Q. Is the Company projecting the 3% AER threshold being met in this filing?

A. No. The AER rate in this filing is $0.0006405/kWh, which is well below the $0.0012813 threshold.

FUEL RIDER:

Q. What modifications does the Company propose to its Fuel Rider?

A. The Company is proposing to change the reconciliation periods from three-month periods on a six-month lag to reconciling the balance of the most current complete month. The reconciliation of this rider will then be the same as other true-up riders in this filing.

Q. Why is this change necessary?

A. Currently the Fuel Rider is reconciled on a six-month lag, and has two true-up periods. The summer and winter periods reconcile together and the spring and fall periods reconcile together. The swings in recovery balances between periods cause rate fluctuations between periods. The new method will stabilize the true-up portion of the Fuel Rider.

Q. Is this change reasonable?

A. Yes. This change allows the Company to reconcile the rider more quickly, and better aligns the costs of fuel with the customers who caused the costs to be incurred.

Q. How does the Fuel Rider change as a result of the Competitive Bidding Process (CBP)?

A. The rate will be calculated in a similar manner as it is today by calculating a retail rate that is adjusted for losses. Because of the CBP, however, the rate will now be blended with the auction result. DP&L witness Dona Seger-Lawson further explains the blending process.

Q. Are there any other changes to the Fuel Rider?

A. Yes. DP&L is proposing additional changes to the methodology used to calculate DP&L's Fuel Rider during the ESP term; the changes are more fully described by DP&L witness Teresa Marrinan. The changes are shown in Schedule 2D.

Q. Were there any changes to the Fuel Rider from the October 5, 2012 filing?

A. Yes, there were two changes. First, I received an update to the projected Fuel Rider based on the average system cost methodology from our Portfolio Analytics department. Second, a new fuel rate went into effect December 1, 2012 and this revised filing reflects that most recent fuel rate.

COMPETITIVE BID TRUE-UP ("CBT") RIDER:

Q. Can you give a brief description of the Competitive Bid True-up (CBT)Rider that the Company is proposing?

A. Yes. The CBT Rider is a true-up mechanism intended to recover the difference between amounts paid to suppliers for the delivery of SSO supply, as a result of the CBP auction(s), and amounts billed to customers through the Competitive Bidding ("CB") Rate. The CBT Rider will be assessed on a bills-rendered basis beginning June 1, 2013, and will be reconciled on a seasonal quarterly basis. The CBT Rider rate will be an energy-based charge that will be the same for all customer classes. The Company is proposing that this Rider will be bypassable for shopping customers.

Q. Can you explain why there would be a difference in amounts paid to suppliers and amounts billed to customers?

A. Yes. Several factors such as switching, supplier default, or penalties will cause a difference in the amount of revenue collected from SSO customers and the amount paid to suppliers. These factors will result in over- or under-recovery from the CB rates. The CBT Rider will ensure that the Company recovers the exact cost of acquiring the generation service supplied by winning bidders, and will also ensure that customers do not pay more than the cost incurred by the Company to provide the CBP portion of the SSO generation service.

Q. How will the CBT Rider be reconciled?

A. The CBT Rider will be reconciled on a seasonal quarterly basis. The rate will initially be set at zero. The Company is proposing that the first true-up filing will be made by May 1, 2013, effective June 1, 2013. On a typical seasonal quarterly true-up schedule, filings will be made no later than February 1st, May 1st, August 1st, and November 1st of each year, with effective dates of March 1st, June 1st, September 1st, and December 1st. The Company is proposing the initial 5-month period with a filing by May 1, 2013 because a typical February 1st filing does not allow enough time to reconcile any data. After the May 1, 2013 filing, the filings will follow the typical seasonal quarterly schedule.

SERVICE STABILITY RIDER ("SSR"):

Q. Can you give a brief description of the Service Stability Rider?

A. Yes. The SSR is a non-bypassable rider that is assessed on all DP&L customers. The Residential, Schools, and Streetlighting tariff classes are assessed through a customer charge, and energy charge. The Secondary, Primary, Primary-Substation, and High

Voltage tariff classes are assessed through a customer charge, energy charge, and demand charge. The SSR justification is fully supported by Company witness William Chambers.

Q. How was the rate designed?

A. The rate was designed in a manner that factored in rate-making principles of stable and predictable revenues and rates, fair distribution among customer classes, and easily understandable rates. Therefore, the rate was first designed by including the energy and demand rates of a prior non-bypassable rate, the Rate Stabilization Charge. Then, a customer charge was added to balance the overall impact across tariff classes. Finally, the energy charge and demand charge were adjusted to achieve parity among tariff classes and to ensure the appropriate revenue recovery.

Q. How does this design achieve parity among rate classes?

A. The rate was designed in a manner that maintained the historical demand and energy rate design of nonbypassable charges, but made improvements to simplify the rates. For instance, Primary, Primary Substation, and High Voltage customers have the same demand and energy rates. The customer charge, modeled after the current customer charge, was included to balance the rate increases to customers and to provide a predictable revenue recovery for the Company.

Q. How does the design satisfy basic rate-making principles?

A. The rate was designed in a manner that factored in the impact to all customer classes while ensuring the Company will recover the appropriate level of revenue.

Q. What changes to the SSR were made from the October 5, 2012 filing?

A. I was provided a new level for the SSR revenue and I incorporated that into my SSR rate design schedules.

RESIDENTIAL HEATING TARIFF:

Q. What changes are being proposed regarding the Residential Heating Tariff?

A. DP&L is proposing to remove Rate B contained in the Tariff. Rate B is a legacy demand rate for residential customers. There are, and have been for decades, only two customers served under this provision.

Q. Why is DP&L proposing this change?

A. DP&L is proposing to remove Rate B because it is manually billed and creates excessive manual adjustments to reconcilable riders. DP&L is attempting to simplify its processes and streamline its true-up riders.

Q. What is the impact on the two customers?

A. On average, DP&L expects that the customers would see a rate decrease; however the amounts vary month by month.

MAXIMUM CHARGE PROVISION:

Q. Can you explain what the Company is proposing in regard to the maximum charge provision?

A. Yes. DP&L is proposing to phase out the maximum charge provision contained in its Secondary and Primary Tariffs. The maximum charge provision works to limit the average rate ($/kWh) charged to customers that have very poor load factors. To phase out the maximum charge provision slowly over time, the Company will increase the maximum charge amount by 10% every quarter until 100% of the SSO is being supplied through the CBP.

Q. How does the maximum charge impact distribution rates?

A. The distribution portion of the maximum charge is dependent on the generation tariff provision. Even though the generation rate would be phased out through the blending plan and replaced with the CBP result, the distribution portion would not be. Under the current maximum charge provision, some customers do not pay their fair share of distribution costs. The proposed change will correct this disparity.

Q. What is the impact to customers of the proposed change?

A. The impact of the maximum charge provision varies based on the customer's billing determinants; however, the phase-out plan is designed to minimize the impact on customer bills. Customers will benefit from easier to understand bills and can make better decisions regarding electric choice and electric usage decisions.

Q. Are there any other changes to the rates and riders?

A. Yes. DP&L is proposing that, similar to other true-up riders in this case, the under- or over-collection balance at the end of the blending period be removed from the Fuel Rider and added into the Reconciliation Rider. In addition, any reconciliation balances greater than 10% of the forecasted rate of the Fuel Rider, AER, or CBT be added to the Reconciliation Rider. The reasonableness of these changes to the under- or over-collection balance is more fully explained by DP&L witness Emily Rabb. DP&L is proposing that carrying charges calculated at the cost of long-term debt, as set forth on WP-12.2, be included in the AER, Fuel Rider, and CBT Rider.

Q. Is it reasonable to including carrying charges?

A. Yes. Carrying charges will be assessed both in cases of under-recovery, which will protect the Company, and will also be assessed in cases of over-recovery, so that the same carrying charges would be included and credited back to the customers in those instances.

IV. TYPICAL BILL COMPARISONS

Q. Can you give a brief description of the Typical Bill Comparisons?

A. Yes. The Typical Bills found in Schedule 10 illustrate the typical bill impacts by tariff class at various usage levels for all of the respective CBP periods 1 through 5 (2013 through May 2017).

Q. What conclusions can you draw from this information?

A. During the first year of the ESP, a typical Standard Service Offer Residential customer using 1,000 kWh or more a month will experience less than a 2% increase as a result of this filing. Most non-residential customers will see slight decreases.

Q. What is the source of the information shown on Schedule 10?

A. The information on Schedule 10 is sourced from the following Schedules:

- Schedule 1 – Current Rates
- Schedule 4 – Adjusted Rates at SSO Blend Percent
- Schedule 5 – Competitive Bid Rate Results
- Schedule 7A – Reconciliation Rider
- Schedule 7C – Transmission Cost Recovery Rider Non-bypassable
- Schedule 7D – Service Stability Rider

- DP&L Tariffs as of October 1, 2012

Q. Can you describe the process that you used to calculate the figures shown in column (E) of Schedule 10?

A. Yes. This figure was derived by multiplying the billing determinants in column (C) by the respective rates in Schedule 7A, Reconciliation Rider.

Q. Can you describe the process that you used to calculate the figures shown in column (F) of Schedule 10?

A. Yes. First, I calculated the TCRR bypassable and TCRR non-bypassable totals by multiplying the billing determinants in column (B) and (C) by the respective rates in Schedules 4 and 7C. Second, I summed the TCRR bypassable and TCRR non-bypassable amounts and subtracted that sum from the current TCRR bill amount in Schedule 1, given the billing determinants in columns (B) and (C). The resulting figure is the proposed Transmission bill impact.

Q. Can you describe the methodology that you used to arrive at the figures shown in column (G) of Schedule 10?

A. Yes. The figures illustrated in column (G) are the difference between the proposed generation rates multiplied by the billing determinants in columns (B) and (C), and current generation rates as of October 1, 2012, multiplied by the billing determinants in columns (B) and (C).

Q. Can you identify which components are included in the proposed generation rates that are part of the calculation in column (G) of Schedule 10?

A. Yes. The proposed generation components and supporting schedules are as follows:

- Base Generation – Schedule 4
- PJM RPM Rider – Schedule 4
- Fuel Rider – Schedule 4
- Competitive Bidding Rate – Schedule 5

Q. Can you identify which components are included in the current generation rates that are part of the calculation in column (G) of Schedule 10?

A. Yes. The current generation components and supporting schedules are as follows:

- Base Generation – Schedule 1
- PJM RPM Rider – Schedule 1
- Fuel Rider – Schedule 1

Q. Can you identify the process that you used to arrive at the figures shown in column (H)?

A. Yes. Column (H) illustrates the proposed impact as a result of implementing the Service Stability Rider. First, I calculated the Service Stability Rider total by multiplying the billing determinants in Columns (B) and (C) by the rates in Schedule 7D. I then subtracted this total by the total derived from multiplying the billing determinants in Columns (B) and (C) by the Rate Stabilization Rates in Schedule 1.

Q. Can you describe the results in columns (I) and (J) of Schedule 10?

A. Yes. Column (I) shows the total dollar impact per month on a bill that results from the proposed rates in this filing. Column (J) illustrates the total percentage impact on a bill as a result of the proposed rates for the respective CBP period.

V. SCHEDULES AND WORKPAPERS

Q. What is shown on Schedule 2D?

A. Schedule 2D shows the proposed adjustment to the current Fuel Rider.

Q. What is the purpose of Schedule 7B?

A. Schedule 7B is an illustrative example of how the CBT Rider is developed.

Q. Can you describe the process that you used to calculate the figures shown on Schedule 7B?

A. Yes. CBP costs (Column C) are subtracted from CB Rate revenue (Column D), which is added to CBT Rider revenue (Column E), to get an initial over- or under-recovery (Column F). Carrying costs are calculated based on the initial over- or under-recovery (see WP-7B). The sum of the initial over- or under-recovery and the carrying costs (Line 15) is multiplied by a gross revenue conversion factor (Line 16) to produce the CBT Rider balance (Line 17). The CBT Rider balance is divided by forecasted metered kWh sales (Line 18) to generate the Forecasted CBT Rider rate (Line 19).

Q. Is this the CBT rate the Company is proposing to implement on the effective date of this rate plan?

A. No. The CBT Rider will be set at zero until the first reconciliation occurs and is implemented.

Q. What is shown on Workpaper 7B?

A. Workpaper 7B "Competitive Bid True-up Rider – Calculation of Carrying Costs" shows the development of carrying costs that are included in the CBT Rider balance.

Q. Can you describe the process that you used to calculate the figures shown on Workpaper 7B and Workpaper 7B.1?

A. Yes. CBP costs (Column D) are subtracted from CB Rate revenue (Column E), which is added to CBT Rider revenue (Column F), to get an initial over- or under-recovery, or "Net Amount" (Column G). Column H, or "End of Month before Carrying Cost" is calculated by adding the "Net Amount" to the "First of Month Balance" (Column C). Column K, or "Less: One-half Monthly Amount," is simply one-half of the current month "Net Amount." Column H and Column K are added to create the "Total Applicable to Carrying Cost" (Column L). Finally, the "Total Applicable to Carrying Cost" is multiplied by the result of 5.034% divided by 12 to generate the monthly carrying charges. Workpaper 7B.1 shows the calculation of the Private Outdoor Lighting rates.

Q. What is shown on Workpaper 7D.1 and Workpaper 7D.2?

A. These workpapers show the rates and revenue associated with the Service Stability Rider.

Q. Can you describe the process that you used to calculate the figures shown on Workpaper 7D.1 and Workpaper 7D.2?

A. Yes. The goal was to design a rate that recovered the appropriate level of revenue while maintain standard rate-design principles. The customer charge was developed by using an allocation method that already exists. The energy and demand charges were based on a previous non-bypassable charge in an effort to minimize any fluctuations between classes.

Q. What is shown on Schedule 10?

A. Schedule 10 illustrates the typical bill impacts by tariff class at various usage levels for all of the respective CBP periods, 1 through 5.

Q. What is the source for the billing determinants on the Typical Bill Comparisons?

A. The billing determinants were derived by DP&L pursuant to Ohio Administrative Code §4901-7-01, Standard Filing Requirements. The billing determinants were selected to represent a range of typical customer consumption patterns. DP&L utilizes typical bill comparisons to assess typical customer impacts when the Company files for changes in cost recovery.

Q. What is shown on Workpaper 8?

A. Workpaper 8 shows the 2013 forecasted billing determinants by Tariff class. This Workpaper was developed by using Workpaper 8A and 8B which is the Revenue Class forecast that is supported by Company witness Aldyn Hoekstra.

Q. How is this Workpaper used?

A. This Workpaper is used in Schedule 1B, Schedule 8, Schedule 5, Appendix D, and Workpaper 8.1, and for the development of the Reconciliation Rider found in Schedule 7A.

Q. What is the basis for the allocation factors?

A. The allocator percentages were developed by using historical data. Each customer is categorized in both a Revenue Class and a Tariff Class. Customer usage data, for each category, is divided by the total to develop a percentage that is then applied to the forecast.

Q. Is there a change to the billing determinants in the Second Revised filing?

A. Yes, since Workpaper 8A and 8B are energy sales only, an allocator was used to develop a billed kW amount for SSO customers. This allocation was previously a percentage of SSO sales to distributions sales. This filing uses a more accurate allocation of kW per kWh by Tariff Class using historical data. This allocation can be located on Workpaper 8.2.

Q. How is this new method more accurate?

A. Since the allocation is for billed kW and several Tariff Classes are not billed on kW, a kW per kWh by Tariff Class allocator will be more accurate than using a ratio between distribution and SSO kWh sales.

Q. Did this change cause the SSR revenue increase?

A. No, this change did not drive the increase to the SSR revenue. This change impacts the CB rate design, and the revenue shown on Schedule 8 and Schedule 1B. It did not impact the Company's financial modeling or forecasting.

Q. Is this method reasonable and does is produce accurate results?

A. Yes, this approach is reasonable and accurate.

Q. Can you explain Appendix C?

A. Yes. Appendix C is a depiction of the true-up process for several true-up riders. It shows that the Company will true-up through the most recent month of available accounting data, file one month prior to the effective date, and have a forecasted rate set every seasonal quarter.

VI. TARIFFS

Q. What is contained on Tariff Sheet No. G26?

A. Tariff Sheet No. G26 contains DP&L's updated Alternative Energy Rider. This rider is bypassable, and not blended with the CBP rates.

Q. What is contained on Tariff Sheet No. G28?

A. Tariff Sheet No. G28 contains DP&L's Fuel Rider which will continue to be adjusted on a seasonal quarterly basis.

Q. What is contained on Tariff Sheet No. G29?

A. Tariff Sheet No. G29 contains DP&L's new Service Stability Rider.

Q. What is contained on Tariff Sheet No. G30?

A. Tariff Sheet No. G30 contains DP&L's proposed Competitive Bid True-up Rider which is a new rider established to true-up the Competitive Bidding rates charged on Tariff Sheet No. G19. This rider will be adjusted on a seasonal quarterly basis.

VII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP)
DIRECT TESTIMONY
OF TIMOTHY G. RICE

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
TESTIMONY OF
TIMOTHY G. RICE

ON BEHALF OF
THE DAYTON POWER & LIGHT COMPANY

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I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Timothy G. Rice and my business address is 1065 Woodman Drive, Dayton, Ohio, 45432.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or the "Company") as Vice President, Assistant General Counsel and Corporate Secretary.

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

A. I earned a Bachelor of Arts degree in Political Science from Ohio Northern University in Ada, Ohio, in 1976. I earned a Juris Doctor degree from Ohio Northern University in 1979. I am licensed to practice law in the State of Ohio, in the U.S. District Court for the Southern District of Ohio, the Sixth Circuit Court of Appeals and the U.S. Supreme Court. I have been employed by DP&L in my current position since 2008. Prior to that, I have held a series of staff attorney positions within the Legal Department of DP&L since 1985.

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

A. I provide legal services to DP&L primarily in connection with finance, SEC compliance, tax, ERISA, corporate governance, including corporate compliance relating to DP&L's Corporate Separation plan and the PUCO Code of Conduct. In addition, I represent the Company as the corporate secretary to the DPL Inc. and DP&L Boards of Directors. In my current role, I report directly to the Senior Vice President and General Counsel of DPL Inc. and DP&L.

II. SUBJECT OF TESTIMONY

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

A. My testimony sponsors DP&L's Third Amended Corporate Separation Plan in this proceeding, which remains substantially unchanged from DP&L's Second Amended Corporate Separation Plan, which was approved by the Commission in Case No. 08-1094-EL-SSO, and is consistent with the Commission's Rules and prior orders. The Third Amended Corporate Separation Plan is attached as Appendix A.

III. DP&L'S THIRD AMENDED CORPORATE SEPARATION PLAN

Q. Is DP&L currently in compliance with its Second Amended Corporate Separation Plan dated October 1, 2008?

A. Yes. DP&L has functionally separated its businesses of providing noncompetitive retail electric service from its businesses of providing competitive retail electric service and services other than retail electric service and has maintained the functional separation organizational structure at the DPL Inc. level. DP&L has implemented and complied with the Code of Conduct that governs its financial and other relationships with its DPL Inc. affiliates, and DP&L has maintained a Cost Allocation Manual. The acquisition of DPL Inc. by The AES Corporation has not changed the functional separation at the DPL Inc. level.

Q. Has the Commission issued any waivers to DP&L regarding the Second Amended Corporate Separation Plan under which DP&L now operates?

A. No.

Q. Under the Third Amended Corporate Separation Plan proposed in this filing, will necessary separation of functions be maintained?

A. Yes. DP&L and its affiliates will continue to provide noncompetitive retail electric services and products or services other than retail electric service separately from either (i) a competitive retail electric service or (ii) a non-electric product or service, in compliance with a Commission-approved Corporate Separation Plan, except as otherwise expressly permitted by state statute.

Q. Please describe DP&L's proposed Third Amended Corporate Separation Plan.

A. DP&L's Third Amended Corporate Separation Plan is substantially unchanged from DP&L's Second Amended Corporate Separation Plan currently on file with the Commission, but has been updated to reflect the acquisition by DPL Energy Resources, Inc. of MC Squared Energy Services, LLC, and the acquisition of DPL Inc. by The AES Corporation. DP&L's operations under the Third Amended Corporate Separation plan with respect to Corporate Separation and the PUCO Code of Conduct will remain unchanged. DP&L will continue to operate all such businesses under a Code of Conduct and separately account for each business with a Cost Allocation Manual, to avoid any cross-subsidies. DP&L will continue its existing education plan that requires each employee to receive training (either on-line or in person) to understand employee obligations under DP&L's Third Amended Corporate Separation Plan.

IV. GENERATING ASSETS

Q. Is DP&L seeking the Commission's authority, pursuant to Ohio Revised Code §4928.17(E), to transfer any ownership interest in its generation facilities in connection with this ESP application?

A. No, not at this time. DP&L continues to study the issue of legal separation of its generation assets. While DP&L is not presently making an application pursuant to Ohio Revised Code §4928.17(E) seeking the Commission's authority to transfer its generation assets into a separate legal entity, DP&L commits to filing such an application with the PUCO by no later than December 31, 2013. In that application, DP&L presently expects to request that the Commission authorize DP&L to transfer its generation assets by December 31, 2017.

V. CONCLUSION

Q. Does this conclude your pre-filed direct testimony?

A. Yes it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 12-426-EL-SSO

CASE NO. 12-427-EL-ATA

CASE NO. 12-428-EL-AAM

CASE NO. 12-429-EL-WVR

CASE NO. 12-672-EL-RDR

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED DIRECT TESTIMONY
OF DONA R. SEGER-LAWSON

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

ELECTRIC SECURITY PLAN (ESP)
SECOND REVISED TESTIMONY OF
DONA R. SEGER-LAWSON

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dona R. Seger-Lawson. My business address is 1065 Woodman Drive, Dayton, Ohio 45432.

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

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

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

A. I received a Bachelor of Science degree in Business Administration with majors in Finance and Management from Wright State University in Dayton, Ohio in 1992. I earned a Masters in Business Administration with a Finance Administration concentration also from Wright State University in August of 1997. I have been employed by DP&L in the Regulatory Operations division since 1992.

Q. How long have you been Director of Regulatory Operations?

A. I assumed my present position on August 25, 2002. Prior to that time, I held various positions in the Rates/Pricing Services/Regulatory Operations division, my most recent prior position being that of Manager, Regulatory Operations, beginning in February 2001.

Q. What are your responsibilities in your current position?

A. I have overall responsibility for all base rate development, for both retail and wholesale electric rates. I am responsible for evaluating regulatory and legislative initiatives, and Commission orders that impact the Company's retail and wholesale rates and overall regulatory operations.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission")?

A. Yes. I have sponsored testimony in Case No. 99-220-GA-GCR; Case No. 00-220-GA-GCR; DP&L's Electric Transition Plan Case, No. 99-1687-EL-ETP; DP&L's Extension of the Market Development Period Case, No. 02-2779-EL-ATA; in Opposition to the Complaints in Case Nos. 03-2405-EL-CSS and 04-85-EL-CSS; in the Company's Rate Stabilization Period Case, No. 05-276-EL-AIR, and in the Company's Electric Security Plan Case, No. 08-1094-EL-SSO.

II. PURPOSE OF TESTIMONY

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

A. The purposes of my testimony are to support the Company's current rates, the Rate Blending Plan, the Request for Waivers, the placeholder for the Alternative Energy Rider-Nonbypassable (AER-N), the competitive retail enhancements and any impacts of the Company's plan on government aggregation efforts. I am sponsoring Schedules 1, 1A, and 1B, Schedule 2 and 2B, Schedules 3, 4, 6, Schedule 7, and Schedule 8. I also support the changes to Tariff Sheet Nos. G10 – G18, and the implementation of Tariff Sheet No. G31.

III. BACKGROUND

Q. Are you generally familiar with Ohio SB 221?

A. Yes. Among other points, I understand that under Ohio SB 221, utilities are permitted to file either a Market Rate Offer (MRO) under Ohio Revised Code §4928.142, or an Electric Security Plan (ESP) under Ohio Revised Code §4928.143.

Q. How were DP&L's current Standard Service Offer (SSO) rates established?

A. DP&L filed an Electric Security Plan (ESP) on October 10, 2008 in Case No. 08-1094-EL-SSO. The Commission issued an Opinion and Order in that case on June 24, 2009 approving DP&L's ESP. DP&L's current ESP rates went into effect in July 2009.

Q. Are any of DP&L's current rates required to expire as of December 31, 2012?

A. No. DP&L's current rate plan, like other rate plans before it, established rates for a period of time. Specifically, Paragraph 1 of the ESP Stipulation reached in Case No. 08-1094-EL-SSO states "the parties agree to extend DP&L's current rate plan through December 31, 2012 except as expressly modified herein." The remainder of the ESP Stipulation further states that certain rates will be charged through December 31, 2012. The ESP Stipulation does not state that any charge will be set to zero on January 1, 2013. Neither does the ESP Stipulation say that DP&L agrees not to request to implement new or to continue existing rates for the period beginning January 1, 2013.

Q. Under which methodology did DP&L choose to implement SSO rates through this filing?

A. DP&L filed this ESP case under ORC §4928.143, and therefore has put forth its filing under the provisions of the ESP section of the Ohio Revised Code.

Q. Why is DP&L proposing to procure a portion of SSO load through a competitive bid?

A. DP&L has been monitoring SSO cases as they have come before the Commission. Every Ohio electric utility that has had an SSO case ruled on by the PUCO in the last 2 years has had all or some portion of the load required to be procured through a competitive bidding process. Although the ESP provisions of the Ohio Revised Code do not discuss competitive bid processes, DP&L believes that the current state policy is to establish standard offer rates through some form of competitive bid.

Q. What type of waivers are the Company seeking?

A. As specified in the Company's application, DP&L is seeking a waiver of Ohio Administrative Code (OAC) §4901:1-35-03(C)(9)(b), certain information required by OAC §4901:1-36-03 and OAC § 4901:1-36-04(B).

Q. Please explain the waiver request for OAC §4901:1-35-03(C)(9)(b).

A. While DP&L is seeking a placeholder for a nonbypassable charge relating to new generation that was used and useful after January 1, 2009, it is proposing to file cost support and full justification for that charge in a separate filing that will be made within six months of a final Commission order in this case.

Q. Has the Commission granted similar requests?

A. Yes, the Commission permitted AEP in its SSO Case No. 11-346-EL-SSO, to have a placeholder tariff for cost recovery of its Turning Point Solar project. On page 24 of the August 8, 2012 order in that case, AEP was directed to address all of the statutory requirements in a future proceeding but was granted the authority to establish the Generation Resource Rider (GRR) at a rate initially set at zero. DP&L is seeking the ability to file in a future proceeding its cost support and legal arguments to set its non-bypassable cost recovery mechanism for the Yankee Solar Generating Facility.

Q. Please explain the waiver requests relating to the Transmission Cost Recovery Rider (TCRR).

A. The Appendix to OAC §4901:1-36-03 requires Schedules B-4, B-5, D-1, D-2, D-3 and D-3a...z to be filed as part of a Transmission Cost Recovery Rider (TCRR) application. These schedules require historical data (costs, revenues, typical bills, reconciliation amounts) to be filed. This information does not exist for DP&L's proposed newly established rider TCRR-N. Secondly, OAC § 4901:1-36-04(B) requires that a transmission cost recovery rider be avoidable by all customers who chose alternative generation suppliers. DP&L is seeking authority to split the TCRR requirements into bypassable and non-bypassable components, and DP&L thus requests a waiver of the requirement that all TCRR components be avoidable. Finally, DP&L requests a one-month delay in the Commission April 15, 2009 Order in Case No. 08-777-EL-ORD, which directs that DP&L file its annual TCRR True-up application no later than February 15 for rates effective May 1. This adjustment will allow DP&L to file its annual application by March 15 for rates effective June 1, which will better align with the PJM delivery year.

IV. ESP RATE BLENDING PLAN

Q. Please explain DP&L's ESP Rate Blending Plan.

A. DP&L's Rate Blending Plan can be found in Book I of this filing. The Company's Rate Blending Plan describes all changes to DP&L's SSO rates and DP&L's plan to procure a portion of the SSO load through a competitive bidding process. The competitive bidding price will be blended with DP&L's existing SSO rates to arrive at a new ESP SSO. Some of the rates that make up DP&L's most recent SSO price are fixed and do not change. Those rates will simply be adjusted downward by the portion of the SSO load that is part of the Competitive Bidding Process ("CBP"). Other rates/riders are rate "trackers" that are adjusted up or down for changes in actual costs and revenues recovered through the rate. It is DP&L's intent that those rates will remain in their current form to the extent possible, but the underlying costs recovered through those rates should decrease over time as more of the SSO load is bid out.

Q. What is the overall impact of the Company's ESP Rate Blending Plan?

A. DP&L's ESP Rate Blending Plan is expected to result in a slight rate increase for SSO residential customers that consume 1000 kilowatt hours (kWh) or more a month, and a total bill decrease of 0-3% for most non-residential SSO tariff classes. Although the amount of the increase or decrease will ultimately depend upon the results of the CBP,[1] using a placeholder for the CBP result, DP&L's estimate is that proposed rates will result in a per-bill increase for a typical residential customer that uses 750 kWh of electricity a month by $2.81, or 2.61% from current rates for the first period. Most non-residential customers should experience between 0 and 3% rate decrease from current standard service offer rates in the first year of the Rate Blending Plan. Most tariff classes are expected to experience SSO rate decreases for periods 2 through 5 as market prices are blended into current rates.

Q. What is the expected revenue impact to the Company?

A. DP&L's standard offer generation revenues will decrease overall as a result of this filing by approximately $46 M per year for the first year, as a portion of DP&L's SSO load will be sourced through a competitive bid and other adjustments were made to the SSO generation rates. As more SSO supply is sourced through the CBP, DP&L will continue to experience a decrease in SSO generation revenues each year throughout the blending period. DP&L's retail transmission rates will increase as a retail nonbypassable transmission charge will be implemented; however this revenue is offset slightly by a decrease in wholesale transmission revenues from Competitive Retail Electric Service (CRES) Providers operating in DP&L's service territory.

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[1] According to DP&L's ESP plan, the first Competitive Bidding Process will take place 8 weeks after a Commission order is issued in this case.

DP&L is seeking a rate increase relating to its nonbypassable charge of approximately $65 M per year.

Q. Are all rates that are currently in effect impacted by the ESP Rate Blending Plan?

A. No. Several rates or riders that relate to distribution service are not affected by the ESP Rate Blending Plan. Those rates are:

1. Energy Efficiency Rider
2. Economic Development Rider
3. Universal Service Fund Rider
4. Excise Tax Rider

These rates will remain in their current form and may be trued-up periodically based on how these rates are currently implemented.

Q. Which of DP&L's current rates/riders are part of the Blended SSO rate?

A. The following rates/riders are part of the Blended SSO rate:

1. Base Generation Rates
2. FUEL Rider
3. Reliability Pricing Model (RPM) Rider
4. Transmission Cost Recovery Rider - Bypassable (TCRR-B)

Q. Which rates are fixed, and thus simply decrease by the percentage of load that is served through the competitive bidding process?

A. DP&L's base generation rates are fixed. Through this filing DP&L has merged its environmental investment rider into the base generation rates. The base generation rates as proposed in Tariff Sheet Nos. G10 – G18 of this filing reflect the percentage of load that will be supplied by DP&L. In other words, the base generation rate for the period beginning January 1, 2013 and going through May 31, 2014 is designed to reflect 90% of DP&L's base generation rate and environmental investment rider as those charges are in place as of March 1, 2012. The base generation rate will be reduced for each period during the ESP by the percentage of load supplied by the utility. Since the CBP is designed to coincide with the PJM auction year starting in 2014, beginning June 1st, 2014, and for every subsequent June through 2017, the blending mix will shift from ESP to competitive bid (CB) in increments of 30%. On June 1, 2016, one hundred percent of the SSO will be procured through the CBP. The periods and the corresponding blend percent are summarized in the table below:

Period	ESP %	CB %
January '13 – May '14	90%	10%
June '14 – May '15	60%	40%
June '15 – May '16	30%	70%
Beginning June '16	0%	100%

Q. Which of the rates/riders that are part of the Blended SSO rate are "trackers" and will continue to be trued-up through the ESP blending period?

A. The FUEL rider, RPM Rider and TCRR are currently trackers and will continue to be trued–up during the ESP blending period. We expect that the level of these charges will decrease over time, since the underlying supply costs should decrease as the percentage of load that is bid out increases.

Q. Is DP&L proposing any adjustments to current rates?

A. Yes. The Company is proposing four changes to rates to implement the ESP blending plan. First, DP&L is proposing to split the TCRR into bypassable and non-bypassable rates. This split is explained in more detail by Company Witness Claire Hale. Second, through this filing, the Company plans to merge the Environmental Investment Rider (EIR) into base generation rates. Third, the Company plans to phase-out the maximum charge provisions contained in current Generation tariffs. The plan to phase-out of the maximum charge provision is explained in more detail by Company Witness Nathan Parke. Finally, the Company plans to move from its current FUEL methodology to a system average cost methodology. This policy change is supported by Company Witness Teresa Marrinan.

Q. Are there any new rates included in DP&L's ESP Rate Blending Plan?

A. Yes. There will be six new rates to implement the ESP Rate Blending Plan. First, to implement the results of the CBP, there will be a new CB Rate that will charge customers for the portion of the SSO load that is procured through the auction process. This rate has been designed to keep the Company's current rate structure to the extent practical. This CB Rate is supported by Company Witness Emily Rabb (whose testimony I have adopted in its entirety).

Second, the costs of energy, capacity, and market-based TCRR costs will not likely match dollar for dollar the revenue recovered from customers through the CB Rate. Thus the Company plans to implement the Competitive Bid True-up (CBT) Rider. This rate could be positive or negative depending upon the difference between the costs associated with procuring the competitive bidding product and the revenues collected. This CBT Rider is supported by Company Witness Nathan Parke.

Third, the Company is seeking authority to implement a non-bypassable Service Stability Rider (SSR) which is sponsored by Company Witness Bill Chambers.

Fourth, the costs of conducting the CBP, the costs of implementing the competitive retail enhancements and any remaining over or under-collection in the true-up trackers at the end of the blending period will be included in a new Reconciliation Rider ("RR"). This charge is supported by Company Witness Emily Rabb (whose testimony I have adopted in its entirety).

Fifth, the Company is seeking approval of a switching tracker that will be implemented January 1, 2013 and begin recovery January 1, 2014. This charge is supported by Company Witness Craig Jackson and is discussed in further detail below.

Finally, the Company is proposing a new Alternative Energy Rider – Nonbypassable (AER-N) as a placeholder to recover costs the Company has incurred from building and operating a solar generation array known as Yankee Solar Generating Facility. The Company plans to make a subsequent filing to cost justify that rate.

Q. Has the Company eliminated any rates?

A. Yes, the Company is proposing to eliminate its Rate Stabilization Charge (RSC) effective January 1, 2013.

Q. How will the "tracker" rates be trued-up?

A. DP&L's current FUEL rider is designed to be trued-up based on a seasonal quarter basis, meaning the rate changes March 1, June 1, September 1, and December 1. The Company plans to implement all of the tracker riders (FUEL, TCRR-B, RPM, and CBT) on a consistent schedule to minimize the number of times the standard service offer rates will be modified throughout the calendar year. The initial tracker riders will be set via filings made one month prior to the effective date of this rate plan that will set the rates through May 31, 2013. The next set of tracker filings will be submitted on or before May 1, 2013 with a requested implementation date of June 1, 2013. The May 1 filing will true up actual costs through March 31, 2012. A graph of the true–up schedule can be found in Appendix C of this filing.

Q. What happens at the end of the rate blending period?

A. The Company plans to remove any under- or over-recovery from the "tracker" rates that are in effect as of the time the SSO load is procured by 100% through the CBP, and place those amounts into a Reconciliation Rider that would recover any rates that are the residual effect of the previous rate structure. The Reconciliation Rider is addressed in detail by Company Witness Emily Rabb (whose testimony I have adopted in its entirety).

V. COMPETITIVE RETAIL ENHANCEMENTS

Q. Please describe the competitive retail enhancements the Company plans to implement.

A. In an effort to further promote the policy of the state to encourage competition, the Company plans to implement six projects that will improve the interaction of CRES Providers with DP&L to ensure a smoother customer choice administrative process. Specifically, the Company plans to implement the following modifications to its Customer Service System (CSS), Electronic Data Interchange (EDI) systems, and Information Technology (IT) systems:

1. Eliminate the minimum stay and return to firm provisions in its generation tariffs.
2. Implement a web-based portal such that CRES Providers can obtain DP&L customer information in more usable and manageable fashion.
3. Implement an auto-cancel feature to our Bill-Ready billing function, such that when DP&L cancels its usage and related charges, it will also cancel the supplier usage and related charges on the customer's bill. This change will eliminate customer confusion and will ensure that customer payments are posted to valid charges.
4. Remove the enrollment verification that requires a CRES Provider to have the first four characters of the customer name on the account as well as the correct account number.
5. Support DP&L's response to Historical Interval (HI) usage data requests via EDI.

6. Provide CRES Providers with a standardized sync list on a monthly basis to ensure that the Company has identified the correct accounts that are served by each CRES Provider.

Q. What is the forecasted cost of these projects?

A. DP&L anticipates that these enhancements will require DP&L to incur approximately $2.5 million in capital improvements to its CSS, EDI, and IT systems.

Q. What is the timing associated with implementing these enhancements?

A. DP&L is working on a schedule for these projects because several of the projects will take a significant amount of planning, programming and administrative implementation. Assuming that the Commission approves rate recovery of these projects, the Company plans to implement most, if not all of these enhancements within 24 months of rate approval.

Q. How and when does the Company plan to recover these costs?

A. Through this filing DP&L seeks the authority to recover a revenue requirement based on the implementation costs of these projects through the quarterly adjusted Reconciliation Rider. Assuming that the Commission approves DP&L's ESP as filed, the Company will begin implementation of these competitive enhancements, and once a given project is used and useful, the Company will place that project into service and will file for cost recovery in the next quarterly Reconciliation Rider filing.

Q. Does the Company or its shareholders benefit from these competitive retail enhancements?

A. No. Neither the Company nor its shareholders benefit from these system enhancements. Most of the projects listed above will improve the administrative processes of CRES Providers operating in DP&L's service territory.

VI. <u>ALTERNATIVE ENERGY RIDER – NONBYPASSABLE (AER-N)</u>

Q. Ohio Revised Code §4928.143 (B)(2)(c) states that a utility may seek:

"The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility.

Does DP&L's Yankee Solar Generating Facility meet all of those requirements?

A. Yes. That facility was: 1) owned or operated by the utility, 2) sourced through a competitive bid process, 3) newly used and useful on or after January 1, 2009, and 4) found by the Commission to be needed as a result of the resource planning process.

Q. Did the Commission find there was a need for the Yankee Solar Generating Facility?

A. Yes. On April 14, 2010 the Commission issued an order in Case No. 10-505-EL-FOR (DP&L's Long-term Forecast Report), and stated in part at Finding 11 "[t]here is a need for a 1.1 MW solar generation facility, known as Yankee 1."

Q. Is the Company seeking a non-bypassable charge for the life of the Yankee Solar Generating Facility?

A. Yes. The Company is seeking authority for a placeholder tariff for the Alternative Energy Rider – Non-bypassable (AER-N) in Tariff Sheet No. G31 and asking for the rate to be initially set to zero.

Q. When will the Company file its cost support for this AER-N?

A. DP&L plans to file its cost support for the AER-N within six months of the Commission order approving the Company's ESP filed in this case.

VII. SWITCHING TRACKER

Q. Can you describe the Company's plans to implement a switching tracker?

A. Yes, as supported by Company Witness Craig Jackson, the Company plans to implement a switching tracker that would defer for later recovery from customers the difference between the level of switching as of the initial ESP filing date (62% of retail load) and the actual level of switching.

Q. For this purpose, how will the Company measure the level of switching?

A. Each month, DP&L will compare the actual monthly switching rate to the August 30, 2012 switching rate reflected in Workpaper 8 pages 5 and 6, as a percentage of distribution sales. The percentage of additional switching occurring after August 30, 2012 will be multiplied by distribution load contained on Workpaper 8 page 1 and 2 and will equal the quantity of additional switched load in megawatt hours (MWh) subject to the switching tracker.

Q. What will be used to calculate the cost of the switching tracker?

A. The costs subject to the switching tracker will equal the difference between the Blended SSO rate and the CB rate in effect. That difference is calculated as dollars per MWh ($/MWh) and multiplied by the quantity of additional switched load in MWh and will be the amount that will be included in the switching tracker regulatory asset account for the month.

Q. How does the Company propose to recover the switching tracker?

A. The Company seeks to recover the balance from all customers beginning January 1, 2014 until the deferral balance plus carrying costs are at a zero balance.

VIII. OTHER

Q. Why did DP&L select Charles River Associates to manage the Competitive Bidding Process (CBP) for DP&L?

A. Charles River Associates (CRA) has significant experience managing commodity auctions and specifically managing electric power auctions in Ohio. CRA has worked with the PUCO in administering and conducting the structured procurement auctions for both FirstEnergy's Ohio electric distribution utilities and Duke Energy Ohio. It was a logical business choice for DP&L to select CRA to manage DP&L's CBP since this will be the first experience DP&L will have in conducting such an auction.

Q. Is DP&L opposed to choosing a different auction manager for future power auctions?

A. No, DP&L is not opposed to choosing a different auction manager in the future. The Company suggests an RFP process be used in the future to select the CBP auction manager. DP&L and the PUCO have issued RFPs in the past to select a FUEL auditor and such a process could be used for the CBP auction manager. DP&L as well as the PUCO and interested stakeholders have an interest in making sure the CBP auction manager is qualified and experienced in conducting such an auction.

Q. Does DP&L have an Operational Support Plan that was approved by the PUCO?

A. Yes. DP&L filed in 99-1987-EL-ETP its original Operational Support Plan. That plan was approved by PUCO order dated September 21, 2000. Since that time, DP&L's Operational Support Plan has been carried out in the form of the Company's Alternative Generation Supplier Coordination Tariff, Tariff Sheet No. G8. DP&L's Tariff Sheet No. G8 governs the relationship between DP&L and CRES Providers who are doing business in DP&L's service territory.

Q. Is DP&L proposing to modify its Tariff Sheet No. G8, and therefore its Operational Support Plan, through this filing?

A. No. DP&L is not requesting any changes to the Company's Tariff Sheet No. G8.

Q. Ohio Administrative Code §4901:1-35-03(C)(6) and (7) require the utility to discuss how its ESP plan impacts governmental aggregation programs. How does DP&L's plan address governmental aggregation programs?

A. DP&L's ESP plan does not provide disincentives for municipal corporations or townships to implement governmental aggregation programs. DP&L has had a number of communities pass ballot issues allowing them to implement opt out governmental aggregation programs, and has several communities that have moved forward with government aggregation efforts in 2012. There is nothing in DP&L's ESP plan that would provide disincentives for governmental aggregation programs to go forward with their plans to aggregate.

Q. Do you adopt the testimony of Company Witness Emily Rabb?

A. Yes. Ms. Rabb is on maternity leave and will not be available to testify on the topics covered by her original testimony at the February 11 hearing date; therefore I am adopting her testimony as filed on October 5, 2012.

IX. SCHEDULES AND WORKPAPERS

Q. What is contained on Schedules 1 and 1A?

A. Schedule 1 contains a summary of DP&L's rates that are part of the blending process, while Schedule 1A contains a listing of all of DP&L's rates that are in effect as of September 1, 2012.

Q. Have you changed anything on Schedules 1 and 1A?

A. Yes, current rates were updated to reflect rates as of December 1, 2012. Specifically, the FUEL rider and the Economic Development Rider were both updated to reflect rates that are currently in effect.

Q. What is contained on Schedule 1B?

A. Schedule 1B shows the revenues that are generated by the current rates that are part of the blending process being applied to forecasted SSO billing determinants.

Q. What is the source of the forecasted SSO billing determinants?

A. The forecasted SSO billing determinants can be found on Workpaper 8 and are supported by Company Witness Aldyn Hoekstra.

Q. Please explain what information is provided on Schedule 2.

A. Schedule 2 contains a summary of the changes that were made to the current rates that are subject to the blending process. The change to each rate/rider is supported by its own separate Schedule or short series of Schedules and sponsored by various Company witnesses.

Q. Are you sponsoring Schedule 2B? If so, what does it contain?

A. Yes. Schedule 2B shows that aside from adding the EIR rate to the base generation rates, the Company is not proposing any other adjustments to its base generation rates.

Q. What is contained on Schedule 3?

A. Schedule 3 contains a summary of the rates that are part of the blending process after the adjustments are made.

Q. How are these rates calculated?

A. The rates contained on Schedule 3 are the sum of the rates contained on Schedule 1 and the rates contained on Schedule 2.

Q. What is contained on Schedule 4?

A. Schedule 4 shows the adjusted rates from Schedule 3 multiplied by the percentage of SSO load supplied by the utility, or the ESP percentage for the period. There is a separate page for each period during the ESP.

Q. Why does Schedule 4, pages 4 and 5 contain rates that are all zero?

A. Pages 4 and 5 are for periods 4 and 5. These pages show that starting June 2016 the blending process is complete at that time. Thus, the generation rates for SSO load will be 100% CB and 0% ESP for periods 4 and 5 during the ESP.

Q. What is contained on Schedule 5 and how did it change from the October 5, 2012 filing?

A. Schedule 5 depicts a projection of the CBP results and shows how those prices would be blended over the rate blending period. Although the expected CBP results did not change, the CB rate changed as a result of a change in demand billing determinants for the secondary, primary, primary-substation, and high voltage tariff classes and updates to the fuel rate.

Q. What is contained on Schedule 6?

A. Schedule 6 shows the Blended SSO rates that will be in effect during each of the five periods during the ESP plan. This schedule takes the ESP rates contained on Schedule 4 and blends them with the CB rate that is contained on Schedule 5 based on the ESP to CB percentages. In other words, column C shows the SSO rate that would be in effect January 1, 2013 through May 31, 2014, assuming the CBP results in the rate that was used in Schedule 5 for illustrative purposes.

Q. What is contained on Schedule 7?

A. Schedule 7 shows a summary of SSO rates that are not part of the blending process. SSO rates that are not part of the blending process are: 1) the Reconciliation Rider (RR), 2) the Competitive Bid True-up (CBT) Rider, 3) the Transmission Cost Recovery Rider - Non-bypassable (TCRR-N), 4) the Service Stability Rider (SSR), 5) the Alternative Energy Rider (AER), and 6) the Alternative Energy Rider – Nonbypassable (AER-N).

Q. Please describe Schedule 8.

A. Schedule 8 shows the revenues associated from this ESP plan. Some of the revenues are based on distribution billing determinants and others are based on SSO billing determinants. Not all revenues contained on Schedule 8 are DP&L revenues.

Q. Can one compare the current revenues contained on Schedule 1B to revenues contained on Schedule 8 and draw any relevant conclusions about the impact of this filing on DP&L revenues?

A. No. The revenues contained on Schedule 1B reflect what DP&L revenues would be if current rates are applied to current billing determinants. The revenues contained on Schedule 8 are projected revenues under the ESP plan; however there are several things that make the Schedule 8 revenues not comparable to Schedule 1B revenues. First, the transmission revenues reflected on Schedule 8 are applied to distribution level billing determinants (where the transmission revenues on Schedule 1 are applied only to SSO billing determinants). This difference is because the majority of TCRR costs are moving from bypassable to non-bypassable charges. Second, the revenues on Schedule 8 associated with the CB rate do not reflect DP&L revenues but instead are revenues that will be provided to the winning bidders of the CBP. Finally, the revenues associated with the RR on Schedule 8 are to recover new costs associated with implementing the CBP and the competitive retail enhancements.

Q. What is the impact of this plan on DP&L's generation revenues?

A. DP&L's generation revenues decrease by approximately $46 M as shown on Workpaper 8.1 page 1.

Q. What is the impact of this plan on DP&L's transmission revenues?

A. The impact on transmission revenues can be found on Workpaper 8.1 page 2. As DP&L is proposing to implement a non-bypassable TCRR-N to recover the majority of its transmission costs, DP&L's current transmission revenues shift from wholesale revenues received from CRES Providers to retail revenues received from retail customers through the TCRR-N. Current transmission revenues cannot readily be compared to proposed transmission revenues because of this change.

X. TARIFFS

Q. What is contained on Tariff Sheet Nos. G10 – G18?

A. Tariff Sheet Nos. G10 – G18 contain DP&L's Base Generation rates. These rates are the ESP rates that will be phased out as part of the CBP. These rates are the sum of base generation rates and EIR rates that are in place today, as phased out per the ESP percentage.

Q. Why are they contained on their own tariff sheets?

A. DP&L's base generation rates have historically been provided on their own separate tariff sheets by tariff class. DP&L contemplated rolling into one single rate, all of the rate/rider components that are part of the blending process; however, we decided against doing so, because there are several components that make up the Blended SSO rate that are still subject to true-up. It is easier administratively to track and true-up revenues collected versus expenses by rate/rider if each rate/rider continues to be separately stated. Therefore, we separately stated each rate/rider that is part of the Blended SSO rate.

Q. What is contained on Tariff Sheet No. G31?

A. Tariff Sheet No. G31 is the placeholder tariff for DP&L's Alternative Energy Rider – Nonbypassable (AER-N). This rate will be initially set at zero and the Company plans to file cost support to establish this charge within 6 months of Commission order approving the Company's ESP filing in this case.

Q. Are DP&L's Distribution Tariffs impacted by any proposal the Company has made in this filing?

A. Yes. DP&L's Distribution Tariffs may be impacted by the new riders that DP&L has proposed in this filing. Distribution tariffs are also impacted by DP&L's proposal to phase-out the maximum charge provision.

Q. Did DP&L file its proposed changes to the Distribution Tariffs?

A. No. Including all the Distribution Tariff in this filing would make the filing unnecessarily voluminous. Once an order is issued in this case, DP&L anticipates that the Commission will give DP&L an opportunity to file proposed tariffs to implement the order. For example, assuming the Commission's order approves the maximum charge phase-out plan, DP&L would file Distribution tariffs in redline form to implement that provision. Likewise, the Distribution tariffs currently list all riders that apply to customers taking distribution service from the Company. That list of riders would have to be modified assuming the Commission approves any new riders proposed in this case such as the Reconciliation Rider, the SSR and the AER-N.

Q. Did DP&L file its proposed changes to Tariff Sheets Nos. G7, G8, and G9?

A. No. The only changes the Company is proposing to those Tariffs is to remove the minimum stay and return to firm tariff provisions and add the new generation riders. Assuming the Commission approves the Company's proposal, the Company will re-file those tariffs in redline form showing exactly what provisions have changed.

XI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Revised
Electric Security Plan

Appendices

The Dayton Power & Light Company

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Data: Actual and Forecasted
Type of Filing: Revised
Work Paper Reference No(s).: WP-8, WP-11, WP-13.1

Witness Responsible: Emily Rabb

Line (A)	Description (B)	Total (C)	Residential (D)	Residential Heat (E)	Secondary (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (POL) (J)	School (K)	Street Lighting (L)	Source (M)
						Jan '13 - May '13						
1	**Retail Market Price (per MWh)**											
2	Weighted Average Auction Price		$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	TFM-2, Page 2, Col (D)
3	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
4	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
5	**Retail Market Price at the Meter (per MWh)**		$45.03	$45.03	$45.03	$43.76	$43.27	$43.27	$45.03	$45.03	$45.03	Line 2 * Line 3 * Line 4
6												
7	Forecasted Distribution Billing Determinants (MWh)	5,616,781	1,339,648	828,423	1,613,472	1,189,600	251,866	334,831	12,685	23,611	22,645	WP-8, Col (D) / 1000, Pg 3 - Pg 1 or WP-8, Col (D) / 1000, Pg 4 - Pg 2
8												
9	**Total CB Amount**	$250,380,270	$60,324,349	$37,303,888	$72,654,644	$52,056,896	$10,898,242	$14,488,137	$571,206	$1,063,203	$1,019,704	Line 5 * Line 7
10												
11	**Retail Capacity Price (per MWh)**											
12	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
13	Final Zonal Capacity Price		$16.46	$16.46	$16.46	$16.46	$16.46	$16.46	$16.46	$16.46	$16.46	WP-13.1, Col (J)
14	Days in Period		151	151	151	151	151	151	151	151	151	Days in the period
15	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
16	CB Capacity Component	$8,330,440	$2,726,315	$947,159	$2,764,013	$1,223,454	$217,854	$422,857	$0	$28,789	$0	Line 12 * Line 13 * Line 14 * Line 15
17												
18	**Capacity Component as a Percent of Total**	3.33%										Line 16 / Line 9
19	Capacity Adjustment - POL & Street Lighting	($52,977)	-	-	-	-	-	-	($19,021)	-	($33,956)	Line 9 * -Line 18, Col (C)
20	Additional Capacity Allocation	$52,977	$17,338	$6,023	$17,578	$7,781	$1,385	$2,689	$0	$183	$0	-Line 19, Col (C) * Line 16 / Line 16, Col (C)
21												
22	**Total Updated CB Capacity Component**	$8,383,418	$2,743,653	$953,182	$2,781,591	$1,231,234	$219,240	$425,546	$0	$28,972	$0	Line 16 + Line 20
23												
24	**CB Energy Component**	$241,996,852	$57,598,035	$36,356,729	$69,890,631	$50,833,442	$10,680,387	$14,065,281	$552,184	$1,034,415	$985,748	Line 9 + Line 19 + Line 20 - Line 22
25												
26						Jun '13 - May '14						
27												
28	**Retail Market Price (per MWh)**											
29	Weighted Average Auction Price		$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	$42.71	TFM-2, Page 2, Col (D)
30	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
31	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
32	**Retail Market Price at the Meter (per MWh)**		$45.03	$45.03	$45.03	$43.76	$43.27	$43.27	$45.03	$45.03	$45.03	Line 29 * Line 30 * Line 31
33												
34	Forecasted Distribution Billing Determinants (MWh)	13,822,395	3,521,948	1,661,697	4,028,699	2,880,926	620,762	969,428	30,165	54,735	54,035	WP-8, Col (D) / 1000, Pg 1 & Pg 2
35												
36	**Total CB Amount**	$615,964,936	$158,593,318	$74,826,216	$181,412,316	$126,069,322	$26,860,372	$41,947,150	$1,358,330	$2,464,717	$2,433,196	Line 32 * Line 34
37												
38	**Retail Capacity Price (per MWh)**											
39	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
40	Final Zonal Capacity Price		$27.73	$27.73	$27.73	$27.73	$27.73	$27.73	$27.73	$27.73	$27.73	WP-13.1, Col (J)
41	Days in Period		365	365	365	365	365	365	365	365	365	Days in the period
42	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
43	CB Capacity Component	$33,923,754	$11,102,274	$3,857,081	$11,255,793	$4,982,226	$887,161	$1,721,984	$0	$117,235	$0	Line 39 * Line 40 * Line 41 * Line 42
44												
45	**Capacity Component as a Percent of Total**	5.51%										Line 43 / Line 36
46	Capacity Adjustment - POL & Street Lighting	($208,913)	-	-	-	-	-	-	($74,844)	-	($134,069)	Line 36 * -Line 45, Col (C)
47	Additional Capacity Allocation	$208,913	$68,371	$23,753	$69,317	$30,682	$5,463	$10,605	$0	$722	$0	-Line 46, Col (C) * Line 43 / Line 43, Col (C)
48												
49	**Total Updated CB Capacity Component**	$34,132,667	$11,170,646	$3,880,834	$11,325,110	$5,012,909	$892,624	$1,732,588	$0	$117,957	$0	Line 43 + Line 47
50												
51	**CB Energy Component**	$581,832,269	$147,491,044	$70,969,135	$170,156,523	$121,087,095	$25,973,211	$40,225,166	$1,283,486	$2,347,482	$2,299,127	Line 36 + Line 46 + Line 47 - Line 49

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Data: Actual and Forecasted
Type of Filing: Revised
Work Paper Reference No(s).: WP-8, WP-11, WP-13.1

Witness Responsible: Emily Rabb

Line (A)	Description (B)	Total (C)	Residential (D)	Residential Heat (E)	Secondary (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (POL) (J)	School (K)	Street Lighting (L)	Source (M)
						Jun '14 - May '15						
1	**Retail Market Price (per MWh)**											
2	Weighted Average Auction Price		$55.23	$55.23	$55.23	$55.23	$55.23	$55.23	$55.23	$55.23	$55.23	TFM-2, Page 2, Col (D)
3	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
4	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
5	**Retail Market Price at the Meter (per MWh)**		$58.23	$58.23	$58.23	$56.59	$55.95	$55.95	$58.23	$58.23	$58.23	Line 2 * Line 3 * Line 4
6												
7	Forecasted Distribution Billing Determinants (MWh)	13,822,395	3,521,948	1,661,697	4,028,699	2,880,926	620,762	969,428	30,165	54,735	54,035	WP-8, Col (D) / 1000, Pg 1 & Pg 2
8												
9	**Total CB Amount**	**$796,527,709**	**$205,083,032**	**$96,760,616**	**$234,591,143**	**$163,031,602**	**$34,731,634**	**$54,239,497**	**$1,756,508**	**$3,187,219**	**$3,146,458**	Line 5 * Line 7
10												
11	**Retail Capacity Price (per MWh)**											
12	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
13	Final Zonal Capacity Price		$125.94	$125.94	$125.94	$125.94	$125.94	$125.94	$125.94	$125.94	$125.94	WP-13.1, Col (J)
14	Days in Period		365	365	365	365	365	365	365	365	365	Days in the period
15	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
16	CB Capacity Component	$154,069,874	$50,422,663	$17,517,516	$51,119,890	$22,627,537	$4,029,175	$7,820,651	$0	$532,442	$0	Line 12 * Line 13 * Line 14 * Line 15
17												
18	**Capacity Component as a Percent of Total**	**19.34%**										Line 16 / Line 9
19	Capacity Adjustment - POL & Street Lighting	($948,234)	-	-	-	-	-	-	($339,709)	-	($608,525)	Line 9 * -Line 18, Col (C)
20	Additional Capacity Allocation	$948,234	$310,330	$107,813	$314,621	$139,263	$24,798	$48,133	$0	$3,277	$0	-Line 19, Col (C) * Line 16 / Line 16, Col (C)
21												
22	**Total Updated CB Capacity Component**	**$155,018,108**	**$50,732,992**	**$17,625,329**	**$51,434,511**	**$22,766,800**	**$4,053,973**	**$7,868,784**	**$0**	**$535,719**	**$0**	Line 16 + Line 20
23												
24	**CB Energy Component**	**$641,509,601**	**$154,660,369**	**$79,243,100**	**$183,471,253**	**$140,404,065**	**$30,702,458**	**$46,418,845**	$1,416,799	$2,654,777	$2,537,933	Line 9 + Line 19 + Line 20 - Line 22
25												
26						Jun '15 - May '16						
27												
28	**Retail Market Price (per MWh)**											
29	Weighted Average Auction Price		$58.75	$58.75	$58.75	$58.75	$58.75	$58.75	$58.75	$58.75	$58.75	TFM-2, Page 2, Col (D)
30	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
31	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
32	**Retail Market Price at the Meter (per MWh)**		$61.95	$61.95	$61.95	$60.20	$59.52	$59.52	$61.95	$61.95	$61.95	Line 29 * Line 30 * Line 31
33												
34	Forecasted Distribution Billing Determinants (MWh)	13,822,395	3,521,948	1,661,697	4,028,699	2,880,926	620,762	969,428	30,165	54,735	54,035	WP-8, Col (D) / 1000, Pg 1 & Pg 2
35												
36	**Total CB Amount**	**$847,391,588**	**$218,184,679**	**$102,942,129**	**$249,577,903**	**$173,431,745**	**$36,947,754**	**$57,700,355**	**$1,868,722**	**$3,390,833**	**$3,347,468**	Line 32 * Line 34
37												
38	**Retail Capacity Price (per MWh)**											
39	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
40	Final Zonal Capacity Price		$134.62	$134.62	$134.62	$134.62	$134.62	$134.62	$134.62	$134.62	$134.62	WP-13.1, Col (J)
41	Days in Period		366	366	366	366	366	366	366	366	366	Days in the period
42	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
43	CB Capacity Component	$165,139,835	$54,045,544	$18,776,154	$54,792,867	$24,253,331	$4,318,673	$8,382,567	$0	$570,698	$0	Line 39 * Line 40 * Line 41 * Line 42
44												
45	**Capacity Component as a Percent of Total**	**19.49%**										Line 43 / Line 36
46	Capacity Adjustment - POL & Street Lighting	($1,016,635)	-	-	-	-	-	-	($364,214)	-	($652,422)	Line 36 * -Line 45, Col (C)
47	Additional Capacity Allocation	$1,016,635	$332,716	$115,590	$337,316	$149,309	$26,587	$51,605	$0	$3,513	$0	-Line 46, Col (C) * Line 43 / Line 43, Col (C)
48												
49	**Total Updated CB Capacity Component**	**$166,156,470**	**$54,378,260**	**$18,891,744**	**$55,130,184**	**$24,402,640**	**$4,345,259**	**$8,434,172**	**$0**	**$574,211**	**$0**	Line 43 + Line 47
50												
51	**CB Energy Component**	**$681,235,118**	**$164,139,135**	**$84,165,975**	**$194,785,036**	**$149,178,414**	**$32,629,081**	**$49,317,788**	**$1,504,508**	**$2,820,135**	**$2,695,047**	Line 36 + Line 46 + Line 47 - Line 49

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Data: Actual and Forecasted
Type of Filing: Revised
Work Paper Reference No(s).: WP-8, WP-11, WP-13.1

Witness Responsible: Emily Rabb

Line (A)	Description (B)	Total (C)	Residential (D)	Residential Heat (E)	Secondary (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (POL) (J)	School (K)	Street Lighting (L)	Source (M)
						Jun '16 - May '17						
1	**Retail Market Price (per MWh)**											
2	Weighted Average Auction Price		$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	$61.00	TFM-2, Page 2, Col (D)
3	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
4	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
5	**Retail Market Price at the Meter (per MWh)**		$64.32	$64.32	$64.32	$62.50	$61.80	$61.80	$64.32	$64.32	$64.32	Line 2 * Line 3 * Line 4
6												
7	Forecasted Distribution Billing Determinants (MWh)	13,822,395	3,521,948	1,661,697	4,028,699	2,880,926	620,762	969,428	30,165	54,735	54,035	WP-8, Col (D) / 1000, Pg 1 & Pg 2
8												
9	**Total CB Amount**	$879,805,882	$226,531,695	$106,880,351	$259,125,920	$180,057,875	$38,363,092	$59,910,650	$1,940,213	$3,520,555	$3,475,531	Line 5 * Line 7
10												
11	**Retail Capacity Price (per MWh)**											
12	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
13	Final Zonal Capacity Price		$174.25	$174.25	$174.25	$174.25	$174.25	$174.25	$174.25	$174.25	$174.25	WP-13.1, Col (J)
14	Days in Period		365	365	365	365	365	365	365	365	365	Days in the period
15	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
16	**CB Capacity Component**	$213,170,363	$69,764,562	$24,237,154	$70,729,243	$31,307,355	$5,574,749	$10,820,617	$0	$736,684	$0	Line 12 * Line 13 * Line 14 * Line 15
17												
18	**Capacity Component as a Percent of Total**	24.23%										Line 16 / Line 9
19	Capacity Adjustment - POL & Street Lighting	($1,312,235)	-	-	-	-	-	-	($470,114)	-	($842,121)	Line 9 * -Line 18, Col (C)
20	Additional Capacity Allocation	$1,312,235	$429,457	$149,199	$435,395	$192,722	$34,317	$66,610	$0	$4,535	$0	-Line 19, Col (C) * Line 16 / Line 16, Col (C)
21												
22	**Total Updated CB Capacity Component**	$214,482,598	$70,194,019	$24,386,353	$71,164,638	$31,500,077	$5,609,066	$10,887,226	$0	$741,219	$0	Line 16 + Line 20
23												
24	**CB Energy Component**	$665,323,284	$156,767,133	$82,643,197	$188,396,677	$148,750,520	$32,788,343	$49,090,034	$1,470,099	$2,783,871	$2,633,410	Line 9 + Line 19 + Line 20 - Line 22
25												
26						Jun '17 - May '18						
27												
28	**Retail Market Price (per MWh)**											
29	Weighted Average Auction Price		$62.60	$62.60	$62.60	$62.60	$62.60	$62.60	$62.60	$62.60	$62.60	TFM-2, Page 2, Col (D)
30	Distribution Loss Factor - Energy		1.04687	1.04687	1.04687	1.01732	1.00583	1.00583	1.04687	1.04687	1.04687	DP&L's Loss Study
31	Gross Revenue Conversion Factor		1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	1.0072	WP-11, Col (C), Line 21
32	**Retail Market Price at the Meter (per MWh)**		$66.01	$66.01	$66.01	$64.14	$63.42	$63.42	$66.01	$66.01	$66.01	Line 29 * Line 30 * Line 31
33												
34	Forecasted Distribution Billing Determinants (MWh)	13,822,395	3,521,948	1,661,697	4,028,699	2,880,926	620,762	969,428	30,165	54,735	54,035	WP-8, Col (D) / 1000, Pg 1 & Pg 2
35												
36	**Total CB Amount**	$902,910,370	$232,483,787	$109,688,619	$265,934,421	$184,782,594	$39,368,726	$61,481,124	$1,991,192	$3,613,057	$3,566,850	Line 32 * Line 34
37												
38	**Retail Capacity Price (per MWh)**											
39	Reliability Obligation		1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-	Appendix B.2, Ln 12
40	Final Zonal Capacity Price		$189.19	$189.19	$189.19	$189.19	$189.19	$189.19	$189.19	$189.19	$189.19	WP-13.1, Col (J)
41	Days in Period		365	365	365	365	365	365	365	365	365	Days in the period
42	Distribution Loss Factor - Demand		1.04364	1.04364	1.04364	1.02352	1.00495	1.00495	1.04364	1.04364	1.04364	DP&L's Loss Study
43	**CB Capacity Component**	$231,447,352	$75,746,098	$26,315,221	$76,793,489	$33,991,613	$6,052,721	$11,748,364	$0	$799,847	$0	Line 39 * Line 40 * Line 41 * Line 42
44												
45	**Capacity Component as a Percent of Total**	25.63%										Line 43 / Line 36
46	Capacity Adjustment - POL & Street Lighting	($1,424,526)	-	-	-	-	-	-	($510,342)	-	($914,184)	Line 36 * -Line 45, Col (C)
47	Additional Capacity Allocation	$1,424,526	$466,207	$161,967	$472,653	$209,214	$37,254	$72,310	$0	$4,923	$0	-Line 46, Col (C) * Line 43 / Line 43, Col (C)
48												
49	**Total Updated CB Capacity Component**	$232,871,878	$76,212,304	$26,477,187	$77,266,142	$34,200,826	$6,089,975	$11,820,674	$0	$804,770	$0	Line 43 + Line 47
50												
51	**CB Energy Component**	$670,038,492	$156,737,690	$83,373,398	$189,140,932	$150,790,981	$33,316,005	$49,732,760	$1,480,849	$2,813,211	$2,652,667	Line 36 + Line 46 + Line 47 - Line 49

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Data: Actual and Forecasted
Type of Filing: Second Revised
Work Paper Reference No(s).: WP-8

Appendix B.1

Witness Responsible: Emily Rabb

		Jan '13 - May '14 Rates						Jun '14 - May '15 Rates					
		Usage / Allocations		Rate Calculation				Usage / Allocations		Rate Calculation			
Line (A)	Description (B)	Forecasted Billing Determinants kWh, kW (C)	Percent of Revenue (D)	Allocated Capacity Cost (E)	Allocated Energy Cost (F)	Allocated Revenue (G)	Rates (per kWh, kW) (H)	Forecasted Billing Determinants kWh, kW (I)	Percent of Revenue (J)	Allocated Capacity Cost (K)	Allocated Energy Cost (L)	Allocated Revenue (M)	Rates (per kWh, kW) (N)
		(C) = WP-8, Col (D), Pg 3 & Pg 4	(D) = App B.3, Col (H)	(E) = App B, Pg 1, Line 22 + 49	(F) = App B, Pg 1, Line 24 + 51	(G) = (D) * [(E) and/or (F)]	(H) = (G) / (C)	(I) = WP-8, Col (D), Pg 1 & Pg 2	(J) = App B.3, Col (E)	(K) = App B, Pg 2, Line 16	(L) = App B, Pg 2, Line 18	(M) = (J) * [(K) and/or (L)]	(N) = (M) / (I)
1	**Residential**			$18,748,314	$312,414,943					$68,358,321	$233,903,470		
2	Energy												
3	First 750 kWh	3,321,031,876	50.05%			$165,742,332	$0.0499069	2,366,727,882	50.13%			$151,517,699	$0.0640199
4	Over 750 kWh	1,540,563,379	19.65%			$65,089,556	$0.0422505	1,155,219,817	20.71%			$62,611,053	$0.0541984
5													
6	**Residential Heating**												
7	Energy												
8	First 750 kWh	1,223,997,733	18.45%			$61,085,905	$0.0499069	853,239,023	18.07%			$54,624,283	$0.0640199
9	Summer, Over 750 kWh	217,781,121	2.78%			$9,201,359	$0.0422505	217,224,907	3.90%			$11,773,240	$0.0541984
10	Winter, Over 750 kWh	1,048,341,764	9.07%			$30,044,106	$0.0286587	591,233,353	7.19%			$21,735,516	$0.0367630
11													
12	**Secondary**			$14,106,701	$240,047,154					$51,434,511	$183,471,253		
13	Demand												
14	Over 5 kW	15,867,506	100.00%			$14,106,701	$0.8890307	11,325,958	100.00%			$51,434,511	$4.5412945
15	Energy												
16	First 1,500 kWh	746,039,643	25.21%			$60,506,530	$0.0811036	524,434,839	24.87%			$45,637,630	$0.0870225
17	Next 123,500 kWh	3,990,081,294	62.27%			$149,481,958	$0.0374634	2,845,950,876	62.35%			$114,399,899	$0.0401974
18	Over 125,000 kWh	906,050,273	12.52%			$30,058,666	$0.0331755	658,313,411	12.77%			$23,433,724	$0.0355966
19													
20	**Primary**			$6,244,143	$171,920,538					$22,766,800	$140,404,065		
21	Demand												
22	All kW	8,816,080	100.00%			$6,244,143	$0.7082675	6,282,027	100.00%			$22,766,800	$3.6241168
23	Energy												
24	All kWh	4,070,525,833	100.00%			$171,920,538	$0.0422355	2,880,926,133	100.00%			$140,404,065	$0.0487357
25													
26	**Primary Substation**			$1,111,864	$36,653,598					$4,053,973	$30,702,458		
27	Demand												
28	All kW	1,504,983	100.00%			$1,111,864	$0.7387885	1,071,435	100.00%			$4,053,973	$3.7836857
29	Energy												
30	All kWh	872,627,653	100.00%			$36,653,598	$0.0420037	620,761,842	100.00%			$30,702,458	$0.0494593
31													
32	**High Voltage**			$2,158,134	$54,290,446					$7,868,784	$46,418,845		
33	Demand												
34	All kW	2,523,426	100.00%			$2,158,134	$0.8552397	1,842,883	100.00%			$7,868,784	$4.2698228
35	Energy												
36	All kWh	1,304,259,195	100.00%			$54,290,446	$0.0416255	969,427,850	100.00%			$46,418,845	$0.0478827
37													
38	**Private Outdoor Lighting**			$0	$1,835,670					$0	$1,416,799		
39	Energy												
40	9500 Lumens High Pressure Sodium	516,965	1.21%			$22,146	$0.0428388	362,577	1.20%			$17,030	$0.0469681
41	28000 Lumens High Pressure Sodium	628,144	1.47%			$26,909	$0.0428388	439,197	1.46%			$20,628	$0.0469681
42	7000 Lumens Mercury	29,258,909	68.28%			$1,253,417	$0.0428388	20,602,916	68.30%			$967,680	$0.0469681
43	21000 Lumens Mercury	11,877,669	27.72%			$508,825	$0.0428388	8,360,224	27.71%			$392,664	$0.0469681
44	2500 Lumens Incandescent	6,178	0.01%			$265	$0.0428388	4,320	0.01%			$203	$0.0469681
45	7000 Lumens Fluorescent	16,946	0.04%			$726	$0.0428388	11,792	0.04%			$554	$0.0469681
46	4000 Lumens PT Mercury	545,809	1.27%			$23,382	$0.0428388	384,099	1.27%			$18,040	$0.0469681
47													
48	**School**												
49	Energy			$146,929	$3,381,896					$535,719	$2,654,777		
50	All kWh	78,346,152	100.00%			$3,528,825	$0.0450415	54,734,766	100.00%			$3,190,496	$0.0582901
51													
52	**Streetlighting**			$0	$3,284,875								
53	Energy									$0	$2,537,933		
54	All kWh	76,680,429	100.00%			$3,284,875	$0.0428385	54,035,176	100.00%			$2,537,933	$0.0469682

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Data: Actual and Forecasted
Type of Filing: Second Revised
Work Paper Reference No(s).: WP-8

Appendix B.1
Page 2 of 3
Witness Responsible: Emily Rabb

		Jun '15 - May '16 Rates						Jun '16 - May '17 Rates					
		Usage / Allocations		Rate Calculation				Usage / Allocations		Rate Calculation			
Line (A)	Description (B)	Forecasted Billing Determinants kWh, kW (C)	Percent of Revenue (D)	Allocated Capacity Cost (E)	Allocated Energy Cost (F)	Allocated Revenue (G)	Rates (per kWh, kW) (H)	Forecasted Billing Determinants kWh, kW (I)	Percent of Revenue (J)	Allocated Capacity Cost (K)	Allocated Energy Cost (L)	Allocated Revenue (M)	Rates (per kWh, kW) (N)
		(C) = WP-8, Col (D), Pg 1 & Pg 2	(D) = App B.3, Col (E)	(E) = App B, Pg 2, Line 49	(F) = App B, Pg 2, Line 51	(G) = (D) * [(E) and/or (F)]	(H) = (G) / (C)	(I) = WP-8, Col (D), Pg 1 & Pg 2	(J) = App B.3, Col (E)	(K) = App B, Pg 3, Line 22	(L) = App B, Pg 3, Line 24	(M) = (J) * [(K) and/or (L)]	(N) = (M) / (I)
1	**Residential**			$73,270,004	$248,305,109					$94,580,372	$239,410,330		
2	Energy												
3	First 750 kWh	2,366,727,882	50.13%			$161,199,076	$0.0681105	2,366,727,882	50.13%			$167,422,758	$0.0707402
4	Over 750 kWh	1,155,219,817	20.71%			$66,611,649	$0.0576614	1,155,219,817	20.71%			$69,183,437	$0.0598877
5													
6	**Residential Heating**												
7	Energy												
8	First 750 kWh	853,239,023	18.07%			$58,114,557	$0.0681105	853,239,023	18.07%			$60,358,283	$0.0707402
9	Summer, Over 750 kWh	217,224,907	3.90%			$12,525,503	$0.0576614	217,224,907	3.90%			$13,009,096	$0.0598877
10	Winter, Over 750 kWh	591,233,353	7.19%			$23,124,329	$0.0391120	591,233,353	7.19%			$24,017,129	$0.0406221
11													
12	**Secondary**			$55,130,184	$194,785,036					$71,164,638	$188,396,677		
13	Demand												
14	Over 5 kW	11,325,958	100.00%			$55,130,184	$4.8675956	11,325,958	100.00%			$71,164,638	$6.2833217
15	Energy												
16	First 1,500 kWh	524,434,839	24.87%			$48,451,881	$0.0923888	524,434,839	24.87%			$46,862,806	$0.0893587
17	Next 123,500 kWh	2,845,950,876	62.35%			$121,454,386	$0.0426762	2,845,950,876	62.35%			$117,471,050	$0.0412766
18	Over 125,000 kWh	658,313,411	12.77%			$24,878,769	$0.0377917	658,313,411	12.77%			$24,062,820	$0.0365522
19													
20	**Primary**			$24,402,640	$149,178,414					$31,500,077	$148,750,520		
21	Demand												
22	All kW	6,282,027	100.00%			$24,402,640	$3.8845169	6,282,027	100.00%			$31,500,077	$5.0143174
23	Energy												
24	All kWh	2,880,926,133	100.00%			$149,178,414	$0.0517814	2,880,926,133	100.00%			$148,750,520	$0.0516329
25													
26	**Primary Substation**			$4,345,259	$32,629,081					$5,609,066	$32,788,343		
27	Demand												
28	All kW	1,071,435	100.00%			$4,345,259	$4.0555512	1,071,435	100.00%			$5,609,066	$5.2350965
29	Energy												
30	All kWh	620,761,842	100.00%			$32,629,081	$0.0525630	620,761,842	100.00%			$32,788,343	$0.0528195
31													
32	**High Voltage**			$8,434,172	$49,317,788					$10,887,226	$49,090,034		
33	Demand												
34	All kW	1,842,883	100.00%			$8,434,172	$4.5766181	1,842,883	100.00%			$10,887,226	$5.9077143
35	Energy												
36	All kWh	969,427,850	100.00%			$49,317,788	$0.0508731	969,427,850	100.00%			$49,090,034	$0.0506382
37													
38	**Private Outdoor Lighting**			$0	$1,504,508					$0	$1,470,099		
39	Energy												
40	9500 Lumens High Pressure Sodium	362,577	1.20%			$18,084	$0.0498757	362,577	1.20%			$17,670	$0.0487351
41	28000 Lumens High Pressure Sodium	439,197	1.46%			$21,905	$0.0498757	439,197	1.46%			$21,404	$0.0487351
42	7000 Lumens Mercury	20,602,916	68.30%			$1,027,586	$0.0498757	20,602,916	68.30%			$1,004,084	$0.0487351
43	21000 Lumens Mercury	8,360,224	27.71%			$416,972	$0.0498757	8,360,224	27.71%			$407,436	$0.0487351
44	2500 Lumens Incandescent	4,320	0.01%			$215	$0.0498757	4,320	0.01%			$211	$0.0487351
45	7000 Lumens Fluorescent	11,792	0.04%			$588	$0.0498757	11,792	0.04%			$575	$0.0487351
46	4000 Lumens PT Mercury	384,099	1.27%			$19,157	$0.0498757	384,099	1.27%			$18,719	$0.0487351
47													
48	**School**												
49	Energy			$574,211	$2,820,135					$741,219	$2,783,871		
50	All kWh	54,734,766	100.00%			$3,394,347	$0.0620145	54,734,766	100.00%			$3,525,090	$0.0644031
51													
52	**Streetlighting**			$0	$2,695,047					$0	$2,633,410		
53	Energy												
54	All kWh	54,035,176	100.00%			$2,695,047	$0.0498758	54,035,176	100.00%			$2,633,410	$0.0487351

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods

Witness Responsible: Emily Rabb

Data: Actual and Forecasted
Type of Filing: Second Revised
Work Paper Reference No(s).: WP-8

Jun '17 - May '18 Rates

Line (A)	Description (B)	Usage / Allocations: Forecasted Billing Determinants kWh, kW (C)	Usage / Allocations: Percent of Revenue (D)	Rate Calculation: Allocated Capacity Cost (E)	Rate Calculation: Allocated Energy Cost (F)	Rate Calculation: Allocated Revenue (G)	Rate Calculation: Rates (per kWh, kW) (H)
		(C) = WP-8, Col (D), Pg 1 & Pg 2	(D) = App B.3, Col (E)	(E) = App B, Pg 3, Line 49	(F) = App B, Pg 3, Line 51	(G) = (D) * [(E) and/or (F)]	(H) = (G) / (C)
1	**Residential**			$102,689,491	$240,111,088		
2	Energy						
3	First 750 kWh	2,366,727,882	50.13%			$171,838,971	$0.0726061
4	Over 750 kWh	1,155,219,817	20.71%			$71,008,330	$0.0614674
5							
6	**Residential Heating**						
7	Energy						
8	First 750 kWh	853,239,023	18.07%			$61,950,390	$0.0726061
9	Summer, Over 750 kWh	217,224,907	3.90%			$13,352,245	$0.0614674
10	Winter, Over 750 kWh	591,233,353	7.19%			$24,650,643	$0.0416936
11							
12	**Secondary**			$77,266,142	$189,140,932		
13	Demand						
14	Over 5 kW	11,325,958	100.00%			$77,266,142	$6.8220403
15	Energy						
16	First 1,500 kWh	524,434,839	24.87%			$47,047,936	$0.0897117
17	Next 123,500 kWh	2,845,950,876	62.35%			$117,935,116	$0.0414396
18	Over 125,000 kWh	658,313,411	12.77%			$24,157,880	$0.0366966
19							
20	**Primary**			$34,200,826	$150,790,981		
21	Demand						
22	All kW	6,282,027	100.00%			$34,200,826	$5.4442342
23	Energy						
24	All kWh	2,880,926,133	100.00%			$150,790,981	$0.0523411
25							
26	**Primary Substation**			$6,089,975	$33,316,005		
27	Demand						
28	All kW	1,071,435	100.00%			$6,089,975	$5.6839425
29	Energy						
30	All kWh	620,761,842	100.00%			$33,316,005	$0.0536695
31							
32	**High Voltage**			$11,820,674	$49,732,760		
33	Demand						
34	All kW	1,842,883	100.00%			$11,820,674	$6.4142291
35	Energy						
36	All kWh	969,427,850	100.00%			$49,732,760	$0.0513011
37							
38	**Private Outdoor Lighting**			$0	$1,480,849		
39	Energy						
40	9500 Lumens High Pressure Sodium	362,577	1.20%			$17,799	$0.0490914
41	28000 Lumens High Pressure Sodium	439,197	1.46%			$21,561	$0.0490914
42	7000 Lumens Mercury	20,602,916	68.30%			$1,011,427	$0.0490914
43	21000 Lumens Mercury	8,360,224	27.71%			$410,415	$0.0490914
44	2500 Lumens Incandescent	4,320	0.01%			$212	$0.0490914
45	7000 Lumens Fluorescent	11,792	0.04%			$579	$0.0490914
46	4000 Lumens PT Mercury	384,099	1.27%			$18,856	$0.0490914
47							
48	**School**						
49	Energy			$804,770	$2,813,211		
50	All kWh	54,734,766	100.00%			$3,617,980	$0.0661002
51							
52	**Streetlighting**			$0	$2,652,667		
53	Energy						
54	All kWh	54,035,176	100.00%			$2,652,667	$0.0490915

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Capacity (RPM) and Energy Prices for Delivery Periods
Reliability Obligation by Class

Data: Actual and Forecasted
Type of Filing: Revised
Work Paper Reference No(s).: None

Witness Responsible: Emily Rabb

Line (A)	Description (B)	Total (C)	Residential (D)	Residential Heat (E)	Secondary (F)	Primary (G)	Primary Substation (H)	High Voltage (I)	Private Outdoor Lighting (J)	School (K)	Street Lighting (L)
			(D) = (D) / (C)	(E) = (E) / (C)	(F) = (F) / (C)	(G) = (G) / (C)	(H) = (H) / (C)	(I) = (I) / (C)	(J) = (J) / (C)	(K) = (K) / (C)	(L) = (L) / (C)
1	**5 CP by Tariff Class - total distribution system**										
2	Class Load (kW) ^1	2,809,632	914,166	317,594	926,807	418,303	75,862	147,248	-	9,653	-
3	**Class Percent**	100.00%	**32.54%**	**11.30%**	**32.99%**	**14.89%**	**2.70%**	**5.24%**	**0.00%**	**0.00%**	**0.00%**
4											
5											
6											
7		**Reliability Obligation by Class**									
8											
9		Total Zonal Load	Residential	Residential Heat	Secondary	Primary	Primary Substation	High Voltage	Private Outdoor Lighting	School	Street Lighting
10		(MW)	Col (C) * Col (D), Ln 3	Col (C) * Col (E), Ln 3	Col (C) * Col (F), Ln 3	Col (C) * Col (G), Ln 3	Col (C) * Col (H), Ln 3	Col (C) * Col (I), Ln 3	Col (C) * Col (J), Ln 3	Col (C) * Col (K), Ln 3	Col (C) * Col (L), Ln 3
11											
12	**DP&L's Distribution Load Obligation**	3,230 ^2	1,051.0	365.1	1,065.6	480.9	87.2	169.3	-	11.1	-
13											
14											
15											

16 Source:
17 ^1 Internal Documents
18 ^2 Total Zonal Load for Dayton was obtained from the PJM website less the portion that relates to non-jurisdiction load.

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Revenue Allocator

Data: Actual and Forecasted
Type of Filing: Second Revisec
Work Paper Reference No(s).: None

Appendix B.3

Witness Responsible: Emily Rabb

Line	Description	Historical Billing Determinants	Total Revenue[1]	Energy Revenue Allocator	Historical Billing Determinants	Total Revenue[1]	Energy Revenue Allocator	Historical Billing Determinants	Total Revenue[1]	Energy Revenue Allocator
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		12 Months			17 Months			5 Months		
1	**Residential**									
2	Energy Charge									
3	0-750 kWh	2,384,333,317	$209,504,454	50.13%	3,337,191,100	$293,229,304	50.05%	952,857,783	$83,724,850	49.85%
4	Over 750 kWh	1,163,813,178	$86,572,687	20.71%	1,548,059,335	$115,155,645	19.65%	384,246,157	$28,582,957	17.02%
5										
6	**Residential Heating**									
7	Energy Charge									
8	0-750 kWh	859,586,032	$75,529,332	18.07%	1,229,953,368	$108,072,436	18.45%	370,367,336	$32,543,104	19.38%
9	Over 750 kWh (S)	218,840,783	$16,278,931	3.90%	218,840,783	$16,278,931	2.78%	-	$0	0.00%
10	Over 750 kWh (W)	595,631,375	$30,053,832	7.19%	1,053,442,705	$53,153,664	9.07%	457,811,330	$23,099,832	13.75%
11										
12	**GS Secondary**									
13	Billed Demand - Over 5.0 kW	11,247,952	$105,969,172		15,800,765	$148,862,118		4,552,813	$42,892,946	
14	Energy Charge									
15	0-1500 kWh	528,335,966	$50,266,042	24.87%	749,669,666	$71,323,797	25.21%	221,333,700	$21,057,755	26.03%
16	1501 - 125,000 kWh	2,867,121,120	$126,001,945	62.35%	4,009,495,928	$176,206,119	62.27%	1,142,374,808	$50,204,174	62.07%
17	Over 125,000 kWh	663,210,423	$25,810,293	12.77%	910,458,864	$35,432,510	12.52%	247,248,441	$9,622,217	11.90%
18										
19	**GS Primary**									
20	Billed Demand - All kW	6,237,618	$72,641,450		8,776,794	$102,211,944		2,539,176	$29,570,494	
21	Reactive Demand - All kVar	3,761,537	$0		5,310,673	$0		1,549,136	$0	
22	Energy Charge - All kWh	2,902,356,547	$112,759,454		4,090,331,888	$158,913,484		1,187,975,341	$46,154,030	
23										
24	**GS Primary-Substation**									
25	Billed Demand - All kW	1,064,057	$13,065,855		1,498,653	$18,402,389		434,597	$5,336,534	
26	Reactive Demand - All kVar	592,773	$0		839,824	$0		247,051	$0	
27	Energy Charge - All kWh	625,379,518	$23,286,444		876,873,618	$32,651,003		251,494,100	$9,364,559	
28										
29	**GS High Voltage**									
30	Billed Demand - All kW	1,879,651	$22,568,638		2,611,730	$31,358,584		732,079	$8,789,946	
31	Reactive Demand - All kVar	837,843	$0		1,179,001	$0		341,159	$0	
32	Energy Charge - All kWh	976,639,156	$36,092,384		1,363,652,571	$50,394,735		387,013,415	$14,302,352	
33										
34	**Private Outdoor Lighting**									
35	Energy Charge - per lamp									
36	9500 Lumens High Pressure Sodium	9,366	$16,431		13,320	$23,367		3,954	$6,936	
37	28000 Lumens High Pressure Sodium	4,609	$18,593		6,575	$26,523		1,966	$7,931	
38	7000 Lumens Mercury	276,749	$933,655		392,017	$1,322,529		115,268	$388,874	
39	21000 Lumens Mercury	54,691	$353,913		77,503	$501,532		22,812	$147,619	
40	2500 Lumens Incandescent	68	$257		97	$366		29	$110	
41	7000 Lumens Fluorescent	180	$899		258	$1,289		78	$390	
42	4000 Lumens PT Mercury	8,999	$64,138		12,755	$90,907		3,756	$26,770	
43										
44	**School Rate**									
45	Energy Charge - All kWh	55,141,923	$4,426,077		78,727,363	$6,319,209		23,585,440	$1,893,133	
46										
47	**Street Lighting**									
48	Energy Charge - All kWh	54,437,128	$2,368,189		77,053,535	$3,352,075		22,616,407	$983,886	
49										
50	Source: [1]Billing Determinants multiplied by Columns (E) thru (G) on Schedule 1 and Column (C) on Schedule 3									