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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 05-276-EL-AIR

DIRECT TESTIMONY

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 05-276-EL-AIR

DIRECT TESTIMONY
OF MARK S. GUERRIERO, P.E.

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

MARK S. GUERRIERO, P.E.

ON BEHALF OF
THE DAYTON POWER & LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark S. Guerriero. 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, Generation Asset Planning.

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

A. I received a bachelor's degree in Chemical Engineering from Youngstown State University in 1982, a master's degree in Finance from Xavier University in 1988, and I am a Licensed Professional Engineer in the State of Ohio. I have been employed at DP&L since graduating in 1982.

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

A. I assumed my present position in January 2002. From 1998 to 2002 I had various staff assignments in Power Production. I was the Operations Manager at Hutchings Station from 1992 to 1998. Prior to the Hutchings position, I managed the Daily Operations section of System Operating for 13 months. I reported to the Group Vice President of Power Production in a staff capacity from 1989 to 1991. Prior to that, I worked at Stuart Station in the Engineering and Performance Services groups from 1982 to 1989.

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

A. In my current position, I am in the Power Production division and am responsible for the development of operational and financial forecasts and providing managerial reporting and analyses to the President, Power Production. This is a collaborative effort with Power Production, Commercial Operations and Corporate Staff areas. I also represent DP&L on several of the committees for the generating units that DP&L co-owns with Columbus Southern Power Company ("CSP") and Cincinnati Gas and Electric Company ("CG&E"). I report to the President, Power Production.

Q. What is the purpose of this testimony?

A. I am sponsoring the Capital and O&M forecast for environmental compliance and physical security costs for the period January 1, 2005 through September 30, 2005. The cost forecast includes: (1) the Capital and O&M cost forecasts for the plants DP&L and DPL Energy LLC ("DPLE") operate; and (2) the Capital and O&M cost forecasts for the plants that DP&L co-owns with CSP and CG&E that they operate. I am also sponsoring for the period January 1, 2005 through September 30, 2005: (1) the forecasted demand for Provider of Last Resort ("POLR") and wholesale customers; and (2) the forecasted cost of fuel, emissions, and purchased power to supply the forecasted demand. Tim Henry is the witness responsible for the historical data for Capital and O&M costs for environmental compliance and physical security and the costs of fuel, emissions, and purchased power. Rick Ullett is the witness responsible for historical POLR and wholesale customer demand.

II. DP&L GENERATION UNITS

Q. In general terms, please describe DPL generation units and whether or not they are co-owned or wholly owned by DP&L and DPLE.

A. There are coal-fired steam units and peaking units, both combustion turbines and diesels. The DP&L-operated coal-fired units are Stuart #1-4, Killen #2, and Hutchings #1-6. The coal-fired steam units that DP&L co-owns with CG&E and CSP that CG&E operates are Beckjord #6 and Zimmer. The coal-fired steam unit that DP&L co-owns with CG&E and CSP that CSP operates is Conesville #4. The coal-fired steam units that DP&L co-owns with CG&E that CG&E operates are East Bend #2 and Miami Fort #7&8.

The DP&L-operated combustion turbines are Tait GT #1-3, Yankee #1-7, Hutchings #7, and Killen GT #1. DP&L also operates diesel generators at Tait, Sidney, Monument, and Stuart. DP&L co-owns Stuart #1-4 and the Stuart diesels with CG&E and CSP. DP&L co-owns Killen #2 and Killen GT #1 with CG&E. The DPLE-operated combustion turbines are Greenville #1-4, Montpelier #1-4, Tait GT #4-7, and Darby #1-6.

Q. Of the generation units that are co-owned, how is co-ownership of those managed between DP&L, CG&E and CSP?

A. There are agreements that enumerate the duties and obligations of the owners and operators of the co-owned units. There is a committee structure that facilitates the execution of these agreements. Each company has a representative on these committees and the committee chair rotates among the co-owners. The executive committee is the Engineering and Operating Committee ("E&O"). DP&L's E&O representative is the President, Power Production. There are a variety of subcommittees that report to the

E&O. I am DP&L's representative on the Production Subcommittee, whose scope includes the exchange of Capital and O&M forecasts. These committees normally meet quarterly, but collaborate on an ad hoc basis as necessary. The Production and Accounting subcommittees provided information used in this case. There is an annual exchange of both Capital and O&M budgets through the Production Subcommittee with a review by the E&O. There is monthly billing which is overseen by the Accounting Subcommittee and which at DP&L is approved by the Production Subcommittee and E&O representatives.

III. DP&L FORECASTING PROCESS

Q. Please describe DP&L's Capital and O&M Forecasting Process.

A. We use a production costing model to determine the cost of fuel, emissions, and purchased power to supply the forecasted demand. The software that we use is PROMOD IV by New Energy ("the model"), which is widely used in the industry. The model determines the least-cost way to serve the POLR demand. The results of the model were included in the 2005 plan that was approved by our Board of Directors.

The model attempts to mirror an economic dispatch process based on various inputs. It makes hourly wholesale sales if there is uncommitted capacity available, once the POLR demand is met, that clears the market price. The model compares the cost of the available generating units to the market price curve and determines when it is economic to purchase power to supply the POLR demand and prescheduled wholesale sales, in lieu of generating it.

Q. What are the inputs to the Promod Model?

A. The inputs to this forecast are a collaborative effort across various departments of the company and include information provided by CG&E and CSP. The POLR demand is provided by the Resource Planning department and reflects the expected energy usage for DP&L's residential, commercial, and industrial customers and the commercial and industrial customers of our affiliate DPLER. The forecast is 1.8% higher than the 2004 weather-normalized actual consumption. Any prescheduled wholesale sales are included and any hourly wholesale sales are an output of the model. Commercial Operations provides the prescheduled wholesale sales and a market price curve. The unit characteristics are input into the model. These characteristics are provided by each generating plant. Commercial Operations provides unit specific fuel prices (coal, oil, and gas) and emission allowance costs. Information for the co-owned units that CG&E and CSP operate is obtained through the Production and Fuels Subcommittees.

Q. Are you responsible for running the model?

A. Yes, I am.

Q. How are the cost of capital projects tracked and recorded within the Company?

A. DP&L uses Oracle Projects software to collect construction and retirement costs. Each project is assigned a project number including the department and work order number. A budget number is also assigned for general ledger reporting.

Q. How are the associated O&M from these capital projects tracked and recorded within the Company?

A. O&M costs are also accumulated in Oracle Projects. Each project is assigned a project number beginning with the department number. In general, each project corresponds to a piece of equipment or an activity. The cost associated with each project is allocated to the appropriate general ledger account for reporting purposes.

IV. CAPITAL AND O&M COSTS

Q. Can you provide a general description of the work you performed regarding Capital and O&M costs forecast for the plants that DP&L and DPLE operate?

A. Yes. I am supporting the Capital and O&M costs forecast associated with environmental projects and physical security for the plants that DP&L and DPLE operate.

Beginning with January 2004, I reviewed the list of Capital projects for each plant and identified the construction and retirement costs and completion dates for environmental projects. I also coordinated efforts to have a representative from each plant review its list of O&M projects and identified those for environmental compliance and physical security. Once these Capital and O&M projects were identified, the costs for each project were provided to the Accounting Department.

Q. Can you provide a general description of the work you performed regarding Capital and O&M costs for the plants that DP&L co-owns with CSP and CG&E that they operate?

A. Yes. I am supporting the Capital and O&M costs associated with environmental projects and physical security for the plants that DP&L co-owns with CSP and CG&E that they operate.

The Capital costs are budgeted and billed by project. The sponsoring company also provides retirement costs and in-service dates. This level of information is sufficient to determine the Capital costs associated with environmental projects and physical security for the plants that DP&L co-owns with CSP and CG&E that they operate. The O&M budgets and monthly billings are divided between labor and non-labor and are by FERC account. This level of detail is not sufficient to determine the O&M costs associated with environmental projects and physical security for the plants that DP&L co-owns with CSP and CG&E that they operate. Therefore DP&L requested and received this information through the Production and Accounting Subcommittees.

Q. **Are you responsible for Workpapers WPC-1.1a and WPC-1.1c?**

A. I am responsible for the forecast portion of those workpapers and the computations to determine the O&M costs associated with environmental projects and physical security. These workpapers support a portion of the information in Schedule Test C-1.1 "Environmental and Fuel Expenses by Account – Test Period".

Q. **What is shown on Workpapers WPC-1.1a and WPC-1.1c?**

A. Workpaper WPC-1.1a "Operations and Maintenance – Test Period" shows the O&M costs associated with environmental projects and physical and cyber security for the twelve months ending September 30, 2005. Workpaper WPC-1.1c "Physical Security O&M – Test" shows the O&M costs associated with physical security for the twelve months ending September 30, 2005. I am sponsoring O&M costs forecast associated with environmental projects and physical security for the period January 1, 2005 through September 30, 2005; Tim Henry is the witness responsible for the historical data on those workpapers.

Q. **What is the source of the information shown on Workpapers WPC-1.1a and WPC-1.1c?**

A. For the plants DP&L and DPLE operate, a representative from each plant reviewed their O&M budgets and identified those items for environmental compliance and physical security. For the plants that DP&L co-owns with CSP and CG&E that they operate, this information was obtained through the Production and Accounting Subcommittees.

V. FORECASTED DEMAND AND COST TO SUPPLY

Q. Are you responsible for Workpapers WPA-5.1 and WPA-5.2?

A. I am responsible for the forecast portion of those workpapers and the computations to determine the POLR and wholesale customer monthly peak demand and energy usage. These workpapers support the information in Summary Schedules A-5.1 "Determination of Jurisdictional Allocators 12 CP Demand Allocator" and A-5.2 "Determination of Jurisdictional Allocators Generated Energy Allocator".

Q. What is shown on Workpapers WPA-5.1 and WPA-5.2?

A. Workpaper WPA-5.1 "Determination of Jurisdictional Allocators – Monthly Peak Demands (MW) 12 Months Ending September 30, 2005" shows the monthly peak demand in MW separated between our POLR and wholesale customers. Workpaper WPA-5.2 "Determination of Jurisdictional Allocators – Monthly Generation (MWHs) 12 Months Ending September 30, 2005" shows the monthly energy usage in MWh separated between our POLR and wholesale customers. I am sponsoring the peak demand and energy usage forecast, separated between our POLR and wholesale customers for the period January 1, 2005 through September 30, 2005; Rick Ullett is the witness responsible for the historical data on those workpapers.

Q. What is the source of the information shown on Workpapers WPA-5.1 and WPA-5.2?

A. The POLR demand forecast provided by the Resource Planning department. The model forecasts hourly wholesale sales and the total POLR and wholesale peak demand and energy usage.

Q. Can you describe the process that you used to calculate the figures shown on Workpapers WPA-5.1 and WPA-5.2?

A. Yes. We use the model to derive this information. The model calculates hourly peaks. We identify the total peak for each month and the difference between the total and POLR peaks is the wholesale peak. The model also separates monthly energy demand into POLR and wholesale categories.

Q. Are you responsible for Workpapers Test WPC-1.2a, WPC-1.2a1, WPC-1.2b, and WPC-1.2c?

A. I am responsible for the forecast portion of those workpapers and the computations to determine monthly fuel quantities and expenses by plant, SO_2 allowance expense, and the fuel and emissions portion of POLR purchased power. These workpapers support the information in Schedule Test C-1.2.

Q. What is shown on Workpapers Test WPC-1.2a, WPC-1.2a1, WPC-1.2b, and WPC-1.2c?

A. Workpaper Test WPC-1.2a1 "Fuel Expense by Plant – Test Period 12 Months Ending September 30, 2005" is the monthly fuel quantities and expense for coal, oil, and natural gas by plant to supply the POLR and wholesale demand. Workpaper Test WPC-1.2a

"Accounts 501 and 547 – Fuel Expense – Test Period 12 Months Ending September 30, 2005" is a summary of Workpaper Test WPC-1.2a1. Workpaper Test WPC-1.2b "Account 509 – Emission Allowances - Test Period 12 Months Ending September 30, 2005" is the monthly SO_2 allowance expense. Workpaper Test WPC-1.2c "Account 555 – Fuel and Emissions Expenses in POLR Purchase Power - Test Period 12 Months Ending September 30, 2005" is the coal, oil, and natural gas, and SO_2 and NO_x allowance expense portion of POLR purchase power. Tim Henry is the witness responsible for the historical data contained on those workpapers.

Q. **What is the source of the information shown on Workpapers Test WPC-1.2a, WPC-1.2a1, WPC-1.2b, and WPC-1.2c?**

A. This information comes from the model.

Q. **Can you describe the process that you used to calculate the figures shown on Workpapers Test WPC-1.2a, WPC-1.2a1, WPC-1.2b, and WPC-1.2c?**

A. Yes. We use the model to derive this cost-to-supply information. The model calculates the least-cost source to supply the energy. Energy is supplied from our generating units or purchase power. For our generating units the model calculates a monthly total for the coal, oil, and natural gas consumed and SO_2 and NO_x emissions, both expense and quantities. These costs are based on the various model inputs and unit characteristics. The monthly coal, oil, and natural gas consumed expense and quantities by plant are found in Workpaper Test WPC-1.2a1 and summarized in Workpaper Test WPC-1.2a.

The model includes emission costs when it makes dispatch decisions. The emission costs are based on unit-specific SO_2 and NO_x emission rates and market-based allowance costs. The total SO_2 emissions are provided to Commercial Operations. They review our SO_2

position and determine the quantity and costs of the SO_2 allowances we expect to purchase. These costs are summarized in Workpaper Test WPC-1.2b. Gary Stephenson is the witness responsible for the SO_2 allowance expense forecast. For the test period we are not required to purchase any NO_x allowances.

Purchase power is supplied from either our OVEC affiliate or economy purchases based on market prices. The model totals OVEC and economy purchases, both quantity and expense, by month. The fuel and emissions cost portion of purchased power used to supply POLR demand can now be forecast. OVEC provided a fuel and emissions cost per MWh forecast. The fuel and emissions cost for OVEC purchases is determined by applying this rate times the forecast MWH's. The economy purchases forecast contained in the model reflects the total purchase cost, not just the fuel and emissions portion. To forecast the fuel and emissions portion of economy purchases we calculated the fuel and emissions cost of our generation per MWh and multiply this rate times the forecast economy purchase volumes. These costs are summarized in Workpaper Test WPC-1.2c.

Q. Are you responsible for Workpaper Test WPB-4.1a?

A. I am responsible for the forecast portion of those workpapers and the computations to determine the monthly inventories of coal, oil, and natural gas, both dollar value and quantities. These workpapers support the information in Schedule Test B-4.1.

Q. What is shown on Workpaper Test WPB-4.1a?

A. Workpaper Test WPC-4.1a "Fuel Stock Balances by Plant – Test Period as of September 30, 2005" is the month-end coal, oil, and natural gas balances in dollars and quantities. I am sponsoring forecast balances for the period January 1, 2005 through

September 30, 2005. Tim Henry is the witness responsible for the historical data on those workpapers.

Q. What is the source of the information shown on Workpaper Test WPB-4.1a?

A. The model calculates the monthly consumption and purchases of coal, oil, and natural gas for each plant.

Q. Can you describe the process that you used to calculate the figures shown on Workpaper Test WPB-4.1a?

A. Yes. The formula used to calculate ending inventory is beginning inventory plus purchases less consumption. Commercial Operations provides a beginning inventory value and quantity for coal, oil, and natural gas for each plant as of December 31, 2004. They also supply a month-ending inventory quantity for the months in 2005. The model then dispatches the units, which results in fuel being consumed. The model calculates the necessary fuel purchases to maintain the desired ending inventory level. All purchases flow through inventory and the monthly consumption and ending inventory is valued at the monthly average inventory value, i.e., the quantity-weighted value of beginning inventory and purchases.

Q. Are you responsible for Workpaper Test WPB-4.3a?

A. I am responsible for the forecasted balances for emission allowances and lime inventories. Tim Henry is the witness responsible for the historical data and emission fees balance forecast.

Q. What is the source of the information shown on Workpaper Test WPB-4.3a?

A. The model calculates our SO_2 emission costs and Commercial Operations determines the quantity and costs of the SO_2 allowances we expect to purchase. Lime is used at Zimmer and East Bend Stations for Flue Gas Desulfurization ("FGD"). These stations are operated by CG&E and they provided us the monthly lime balances.

Q. Can you describe the process that you used to calculate the emission allowances figures shown on Workpaper Test WPB-4.3a?

A. Yes. Accounting provided the inventory value for emission allowances as of December 31, 2004. Commercial Operations provided the monthly forecast SO_2 allowance purchases. The monthly consumption of allowances comes from the model. The formula used to calculate ending inventory is beginning inventory plus purchases less consumption.

Q. Are you responsible for Workpaper Test WPC-1.6a?

A. I am responsible for the capacity factor calculations and the purchased power forecast. This workpaper supports the information in Schedule Test C-1.6.

Q. What is shown on Workpaper Test WPC-1.6a?

A. Workpaper Test WPC-1.6a "SCR Run Cost Calculation" calculates the capacity factor for our units with Selective Catalytic Reduction ("SCR") equipment for the 12 months ending September 30, 2005 and the ozone season which is May 1 through September 30, 2005. The workpaper also calculates the cost of purchased power for the 12 months ending September 30, 2005. Tim Henry is the witness responsible for the historical purchased power costs.

Q. What is the source of the information shown on Workpaper Test WPC-1.6a?

A. The historical generation is from DP&L's accounting records. The forecast generation and purchase power volumes and costs are from the model.

Q. Can you describe the process that you used to calculate the figures shown on Workpaper Test WPC-1.6a?

A. Yes. Capacity factor is the actual or forecast generation in MWh's divided by the unit's MW capability and period hours. The annual capacity factor applies to the unit output reduction for dilution air fans. The ozone season capacity factor applies to the unit output reduction due to the operation of SCR equipment. The purchased power rate in dollars per MWh is the purchased power cost in dollars divided by the number of MWh's purchased.

Q. Are you responsible for Schedule S-1?

A. I am responsible for the Power Production Capital Budget Forecast for the years 2005 through 2009.

Q. What is shown on Schedule S-1?

A. Schedule S-1 "Capital Budget Forecast' is the construction and capitalized interest forecast for environmental compliance projects that are greater than 5% of the total Power Production Capital Budget.

Q. What is the source of the information shown on Schedule S-1?

A. Schedule S-1 is the Power Production portion of the company forecast. The forecast includes the construction projects for the plants DP&L and DPLE operate and for the plants that DP&L co-owns with CSP and CG&E that they operate.

Q. Can you describe the process that you used to calculate the figures shown on Schedule S-1?

A. Yes. I calculated 5% of the total annual Power Production Capital Budget for each year 2005 through 2009. I then determined that there were four environmental compliance projects that met the greater than 5% test. The four environmental compliance projects are the FGD projects at Stuart Station, Killen Station, Miami Fort #7, and Miami Fort #8. All four of these projects were started in 2004 and will be completed between 2006 and 2009. I obtained the construction and capitalized interest costs prior to December 31, 2004 from accounting records. I forecasted capitalized interest based on the budgeted construction costs using a 6% annual rate obtained from DP&L's Treasury department. Capitalized interest, prior to the in-service date, was forecast monthly on the accumulated construction costs and on a month-by-month basis post-in-service.

Q. What will be the impact of meeting the even more stringent environmental requirements during 2005 through 2009?

A. The Company estimates that it will be required to spend over $600 million dollars during this time frame on generation capital projects. Projects for SCR and FGD amount to over $450 million or 75% of the generation capital budget during those years. Based on what we know today, we also anticipate increases in excess of $15 million for annual operating costs and approximately $15 million more for depreciation as a result of environmental compliance requirements.

Q. The Company made a filing of amended schedules in this case on April 15, 2005. Does your testimony refer to these amended schedules?

A. Yes. Throughout my testimony I refer to the schedules and workpapers as amended by the April 15, 2005 filing.

Q. What corrections were required to the Schedules or Workpapers you support?

A. In the original filing a typographical error changed the September 2005 Lime balances at the Company's East Bend station in Workpaper Test WPB-4.3a. The original filing erroneously included Physical Security for the entire Conesville #4 unit, not just DP&L's share, in Workpaper Test WPC-1.1c, this change did not affect any other schedule or workpaper as the total O&M was completed correctly. Finally Workpaper Test WPC-1.1a erroneously included estimated deferred Emission Fee expenses in Account 502 as O&M expenses for Stuart station for the month September 2005. The Company has corrected these errors in its amended application filed on April 15, 2005.

VI. DP&L'S EXPENDITURES ON SCR EQUIPMENT WERE REASONABLE AND PRUDENT

Q. ·Can you identify the principal environmental equipment installed at DP&L-owned generation plants since June 1, 2002?

A. Yes. Since June 1, 2002, SCR equipment has been installed at the following DP&L-owned plants: Stuart, Killen, East Bend, Zimmer, Miami Fort 7, and Miami Fort 8. This equipment is used to reduce the NO_x levels emitted from our generating unit boilers. Vaporized ammonia is injected into the boiler outlet flue gas stream. The ammonia reacts with the NO_x, in the presence of a catalyst, to form nitrogen and water.

Q. What did DP&L do to acquire the SCR equipment at a reasonable price?

A. DP&L employed a three-tier approach to SCR projects. First, proposals were solicited for engineering and construction management. An open book contract was awarded with incentives based on an installed cost target. Second, alliances were formed with key suppliers for labor, large equipment, and material. This allowed DP&L to secure these resources in advance of others. Third, competitive lump-sum bids were solicited for the smaller equipment and commodity items. We are not aware of a standard, published source to compare the cost of SCR projects. We were able to collect budget data for 23 SCR projects. This sample contains DP&L operated units, CG&E units co-owned with DP&L, projects our engineering and construction manager has knowledge of, and other sources. All of our SCR projects were at or below the average cost on a per kW basis. Killen and Stuart Stations were the two lowest cost projects in the sample.

Q. Is DP&L's investment in SCR equipment reasonable and prudent?

A. Yes. As explained in Amy Wright's testimony, DP&L was required to take action to reduce NOx emissions to comply with USEPA regulations. DP&L determined that the lowest-cost method of compliance with those regulations was to acquire SCR equipment. DP&L acquired the lowest-cost SCR equipment that was available in the market that would satisfy DP&L's and the USEPA's requirements.

VII. CONCLUSION

Q. Please summarize your testimony.

A. In summary, I am sponsoring the forecasts for the period January 1, 2005 through September 30, 2005 for Capital and O&M for environmental compliance and physical security costs; demand for POLR and wholesale customers; and the cost of fuel, emissions, and purchased power to supply the forecasted demand. All of these costs are included in the 2005 corporate plan that was approved by our Board of Directors in December 2004.

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. 05-276-EL-AIR

DIRECT TESTIMONY
OF TIMOTHY E. HENRY

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ■ OPERATING INCOME
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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

TIMOTHY E. HENRY

ON BEHALF OF
THE DAYTON POWER & LIGHT COMPANY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy E. Henry. 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 Assistant Controller.

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

A. I received a Bachelor of Science degree in Accounting and Finance from Wright State University in December 1986 and a Masters in Business Administration from the University of Dayton in 1998. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Ohio Society of Certified Public Accountants. From 1987 until 1989 I was employed as an Internal Auditor for Banc One Corporation. From 1989 until 1990 I was employed as an Internal Auditor for Metromedia Steakhouses (parent company for Ponderosa and Bonanza). In 1990, I joined Miami Valley Hospital as a Senior Financial Analyst responsible for financial forecasting and budgeting. In 1993, I was promoted to Manager of Financial Accounting where I was responsible for Financial Statement preparation and various other accounting functions. In 1999, I joined NCR Corporation where I had various roles in Corporate Consolidations, External Reporting and finally leading the Sarbanes-Oxley 404 (Sox 404) project. I joined DP&L in November 2003 as the Corporate Accounting Manager and was later promoted to Assistant Controller.

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

A. I assumed my present position in June 2004.

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

A. In my current position, I am involved with SEC filings, FERC filings and internal management reporting. In addition, I am responsible for overseeing the property, plant and equipment function and the accounting for the financial asset portfolio. I report to the Corporate Controller of DP&L.

II. <u>ENVIRONMENTAL PLANT AND ASSOCIATED OPERATION AND MAINTENANCE EXPENSES</u>

A. *<u>Overview Of Testimony</u>*

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

A. In general, my testimony will cover certain environmental-related operation and maintenance expenses, plant and depreciation data as they appear in DP&L's application for an increase in rates and a description of the process followed to derive the data. I will support and explain data related to parts of the Base and Test Period Rate Base and Expense Schedules contained in the filing.

Q. What is the time period covered in this proceeding?

A. There is both a base period and a test period in this proceeding. The base period is the twelve months ended May 31, 2003 and the date for measuring plant investment is May 31, 2003. The test period in this case is the twelve months ended September 30, 2005, with a date certain of March 31, 2005.

Q. How many months of forecasted data are contained in this filing?

A. The base period contains all actual information while the test period consists of three months of actual data (October through December 2004) and nine months of forecasted data (January through September 2005).

Q. Does your testimony refer to the Base and Test period schedules and workpapers contained in the Company's April 15, 2005 amended filing?

A. Yes.

B. Identification Of Schedules And Workpapers For Base And Test Period Rate Base And Expenses

Q. What data is depicted on the Schedules that you sponsor?

A. The data in this proceeding are determined by the scope of the Stipulation and Recommendation in Case No. 02-2779-EL-ATA, specifically Section IX.E. The various schedules that I sponsor reflect those amounts pertaining to DP&L and DPL Energy for generation-related environmental property and O&M costs, plus physical and cyber security costs.

Q. What Schedules do you sponsor?

A. There are two sets of schedules for this proceeding, one set for the base period and one set for the test period. I sponsor all or parts of the following schedules:

Base and Test B-1	Rate Base Summary
Base and Test B-2	Environmental Plant In Service Summary by Major Property Groupings
Base and Test B-2.1	Environmental Plant In Service by Accounts

Test B-2.2	Environmental Gross Additions and Retirements
Base and Test B-3	Environmental Reserve for Accumulated Depreciation
Base and Test C-1	Adjusted Expenses
Base and Test C-1.1	Environmental and Fuel Expenses by Account

I do not sponsor any of the forecasted data on those schedules; the forecasted data is sponsored by either Company Witness Guerriero or Company Witness Stephenson.

Q. What workpapers do you sponsor?

A. There are two sets of workpapers for this proceeding, those for the base period and those for the test period. I sponsor all or parts of the following workpapers:

Base WPB-2.1a	Gross Additions and Retirements from June 1, 2002 through May 31, 2003
Base WPB-3.1	Computation of the Environmental Reserve for Accumulated Depreciation at May 31, 2003 for DP&L
Base WPB-3.2	Computation of the Environmental Reserve for Accumulated Depreciation at May 31, 2003 for DPL Energy
Base WPB-4.1a	Fuel Stock Balances by Plant, for 13 Months Ending May 31, 2003
Base WPB-4.3a	Environmental Investment Balances, for 13 Months Ending May 31, 2003

Base WPC-1.1a	Environmental Operation and Maintenance Expenses by Account and Station for the 12 Months Ending May 31, 2003, excluding fuel, purchased power (fuel and emissions only), emission allowances and depreciation expenses.
Base WPC-1.1b	Computation of the 12 Months Ending May 31, 2003, by month, of Depreciation Expense for DP&L and DPL Energy
Base WPC-1.1c	Physical Security O&M, for 12-Months Ending May 31, 2003
Base WPC-1.1d	Cyber Security O&M, for 12 Months Ending May 31, 2003
Base WPC-1.2a	Computation of Accounts 501 and 547 Fuel Expense, for 12 Months Ending May 31, 2003
Base WPC-1.2a1	Computation of Fuel Expense by Plant, for 12 Months Ending May 31, 2003
Base WPC-1.2b	Computation of Account 509 Emission Allowances, for 12 Months Ending May 31, 2003
Base WPC-1.2c	Account 555 Fuel and Emission Expenses in POLR Purchase Power, for 12 Months Ending May 31, 2003
Test WPB-3.1	Computation of the DP&L Environmental Reserve for Accumulated Depreciation at March 31, 2005
Test WPB-3.2	Computation of the Environmental Reserve for Accumulated Depreciation at March 31, 2005 for DPL Energy

Test WPB-4.1a	Fuel Stock Balances by Plant, for 13 Months Ending September 30, 2005
Test WPB-4.3a	Environmental Investment Balances, for 13 Months Ending September 30, 2005
Test WPC-1.1a	Environmental Operation and Maintenance Expenses by Account and Station by month for the period October 2004 through September 2005, excluding fuel, purchased power (fuel and emissions only), depreciation and taxes.
Test WPC-1.1b	Calculation of monthly Depreciation Expense for the 12 Months Ending September 2005 for DP&L and DPL Energy
Test WPC-1.1c	Physical Security O&M, for 12 Months Ending September 30, 2005
Test WPC-1.1d	Cyber Security O&M, for 12 Months Ending September 30, 2005
Test WPC-1.2a	Accounts 501 and 549 Fuel Expense, for 12 Months Ending September 30, 2005
Test WPC-1.2a1	Fuel Expense by Plant, for 12 Months Ending September 30, 2005
Test WPC-1.2b	Computation of Account 509 Emission Allowances, for 12 Months Ending September 30, 2005

I do not sponsor any of the forecasted data on those workpapers; the forecasted data is sponsored by either Company Witness Guerriero, Company Witness Stephenson, or Company Witness Ullett.

C. *Explanation Of Base Period Schedules*

Q. What is shown on Schedule Base B-1?

A. Schedule Base B-1, "Rate Base Summary," presents the environmental rate base as of May 31, 2003, which is the sum of several amounts developed on supporting schedules and sponsored by several Company witnesses.

Q. What is the source of the information shown on the Base B-2 and Base B-2.1 Schedules?

A. The information on these schedules was developed from accounting records of the Company for the actual data through May 31, 2003. DP&L accurately maintains separate property accounting records for its generation operations.

Q. How did you determine the environmental plant balances?

A. The Company's fixed asset system does not separately maintain environmental property as this information is commingled with all of the Company's plant in the fixed asset system. Therefore, it was necessary to identify manually the environmental plant assets using company records.

Q. How was this separation accomplished?

A. The Company's tax department, along with its partners (Cinergy and AEP) which co-own several generating plants in common with the Company, identify and keep track of environmental property additions and retirements in order to file for property tax exemption for qualified environmental property under Ohio law, as I understand it. The December 31, 2001 balances were used as the beginning point for the purposes of coming up with the monthly environmental plant balances necessary to compute the balances for the base period and through September 30, 2005 of the test period. Monthly environmental additions and retirements were identified and were used to compute the monthly environmental plant balances. Estimates were used to calculate the balances from January 2005 through March 2005 as well as through September 2005; those estimates are sponsored by Company Witness Guerriero. These monthly computations were necessary in order to calculate environmental depreciation expense and the environmental depreciation reserve.

Q. How are environmental capital projects entered into the Company's accounting system?

A. As with all capital projects, a capital project number is assigned after the project is approved. Labor and material costs are captured as well as Construction Period Interest (CPI), if applicable. When the project is completed, accounting personnel unitize the project to the Fixed Asset System, which stores the information by plant account, retirement unit and location. This system reflects all additions and retirements associated with each individual asset and supports the information interfaced to the general ledger system. These accounting records are accurate; they are reviewed by the Company's external auditors, KPMG, in accordance with their general audit testing and SOX 404 testing. In addition, these records are reviewed by Ernst & Young which serves as our internal auditors. The Staff of this Commission has also investigated the Company's property records in prior cases and found those records to be accurate.

Q. What is shown on Schedule Base B-2?

A. Schedule Base B-2 displays the environmental investment in plant in service for DP&L and its affiliates for generation property at May 31, 2003. The summary totals provided on this schedule were carried forward from the plant account detail shown on Schedule Base B-2.1, line 57. The total amount is carried forward to Schedule Base B-1, line 1.

Q. **What does Schedule Base B-2.1 show?**

A. Schedule Base B-2.1 provides the same information as that shown on Schedule Base B-2 at the environmental plant account level of detail. The total lines for generation property are carried forward to Schedule Base B-2. Workpaper Base WPB-2.1a, which I adopt as part of my testimony, shows the gross additions and retirements from the beginning of the Base Period (June 1, 2002) through the end of the Base Period (May 31, 2003).

Q. **What is shown on Schedule Base B-3?**

A. Schedule Base B-3 sets forth the environmental reserve for accumulated depreciation by plant account for the generation group at May 31, 2003. The primary source of this information is Workpaper Base WPB-3.1 for the computation of the total DP&L environmental reserve balance, which I adopt as part of my testimony.

Q. **What was the process used to determine the base period environmental reserve at May 31, 2003?**

A. As previously explained, the Company's Fixed Asset System does not separately maintain environmental property, as well as the associated depreciation reserve. It was therefore necessary to estimate the environmental portion of the generation company reserve.

Q. **How was this accomplished?**

A. The environmental reserve was determined by taking the relationship by plant account of the environmental property for those accounts having environmental property at May 31, 2003 to total generation property at May 31, 2003 and multiplying those percentages times the total generation company reserve for those accounts that had environmental property. The resulting amounts were the environmental reserve by account. This calculation is a reasonable approach for the purposes of this proceeding.

Q. How was the reserve for DPL Energy determined?

A. Since the plants owned by DPL Energy are relatively new, the environmental reserve was determined by manually calculating monthly environmental depreciation expense since each unit's in-service date, thereby accumulating these costs for the environmental reserve at May 31, 2003. Workpaper Base WPB-3.2, which I adopt as part of my testimony, shows the details of this calculation.

Q. What is shown on Schedule Base C-1?

A. Schedule Base C-1 shows summarized total Operation and Maintenance Expenses for the 12 months ended May 2003. These expenses are categorized as follows:

- Fuel and Emission Expenses
- Purchased Power Fuel and Emission Expenses
- Other Operation and Maintenance
- Depreciation Expense
- Taxes Other Than Income Taxes

Q. What are the sources for that data?

A. The sources for these items are shown under the source column on Schedule Base C-1 namely specific lines on Schedules Base C-1.1, C-1.2 and C-1.3.

Q. **What is shown on Schedule Base C-1.1?**

A. Schedule Base C-1.1 shows DP&L's and DPL Energy's operating expenses by account. I am responsible for all of the accounts with the exception of account number 555 Purchased Power (Fuel and Emissions only) which is an amount calculated on Workpaper Base WPC-1.2c, and is sponsored by Company Witness Ullett and myself. I sponsor Columns B, C and D on page 2 of 2 of Workpaper Base WPC-1.2c, OVEC purchased power information. Workpaper Base WPC-1.1a, depicts, by station, the O&M expenses, except fuel and emission allowances, included in Schedule Base C-1.1. The fuel (accounts 501 and 547) comes from Workpapers Base WPC-1.2a and Base WPC-1.2a1, line 2 of Workpaper Base WBC-1.1a and emission allowances (account 509) information comes from Workpaper Base WPC-1.2b line 14. Workpaper Base WPC-1.1b supports the calculation of depreciation expense for the base period. I adopt all of these workpapers as part of my testimony.

Q. **What is the source of the data contained in the accounts that you sponsor?**

A. The source of the fuel-related and emission allowance accounts is the Company's general ledger system. The figures for the other operation and maintenance accounts, administrative and general expense, and depreciation expense were obtained from different sources. The operation and maintenance expenses for DP&L were obtained from the Company's project accounting module and for DPL Energy from environmental invoices and labor information. Cinergy and AEP supplied the data for the plants that they operate which was then allocated to DP&L's share. The depreciation expense was manually calculated based upon monthly environmental plant balances throughout the base period. The insurance expense was calculated by taking the percentage of environmental plant to total plant times the applicable property and casualty insurance expense during the period.

Q. Why was it necessary to use the Company's project accounting module and data furnished by Cinergy and AEP to assemble the environmental-related O&M expenses?

A. The Company's general ledger does not isolate the environmental O&M data from the plants it operates and the plants its partners (Cinergy and AEP) operate. These costs are intermingled with other costs in the various expense accounts, similar to what occurs in our fixed asset system. Therefore, it was necessary for DP&L, DPL Energy, Cinergy and AEP to break out those costs. Cinergy and AEP provided the environmental-related O&M and physical security costs for the base period for the plants that they operate. (Cinergy operates Beckjord, Miami Fort, Zimmer and East Bend Stations. AEP operates Conesville Station.)

Q. How did DP&L capture the data for the plants it operates?

A. The Company's project accounting module contains numerous projects and tasks for capturing O&M expenses. These various projects/tasks for each station operated by DP&L were examined and those relating to environmental requirements were given a special code. A report was then run for the 12 months ended May 2003 to provide the necessary data. Each project/task relates to an appropriate general ledger account. Once the totals by project/task were obtained, DP&L's share of those costs for Stuart (35%) and Killen (67%) Stations were determined. The remaining wholly-owned stations'

O&M expense is 100% DP&L. DP&L operates two commonly-owned stations, Killen and Stuart and five wholly-owned plants.

Q. How was the data for DPL Energy derived?

A. DPL Energy personnel analyzed various invoices paid throughout the base period to determine the amounts applicable to environmental expenses. Payroll expenses for the period were also analyzed to determine the applicable portion for environmental expenses. Environmental insurance-related expense was calculated by taking the percent of DPL Energy environmental property to total DPL Energy property times the insurance expense for the period. (DPL Energy operates four power stations: Greenville, Darby, Tait 4-7 and Montpelier.)

Q. How was the 12 months depreciation expense for DP&L and DPL Energy calculated for the Base Period?

A. Monthly environmental plant balances by account for each of the stations for the June 2002 through May 2003 period were multiplied by the applicable monthly depreciation rate to compute the monthly depreciation expense. These monthly balances were then totaled. The same process was used to determine the monthly depreciation expense for DPL Energy. For details of these computations, see Workpaper Base WPC-1.1b, which I adopt as part of my testimony.

Q. Were there any physical and cyber security costs included in the total O&M costs?

A. Yes. Physical security expenses amounted to $441,190 and are included as part of GL Account 506 and cyber security expenses amounted to $10,665 (GL Accounts 556, 921 and 935). Workpapers Base WPC-1.1c and Base WPC-1.1d support these amounts, which I co-sponsor with Company Witness Guerriero (physical) and Company Witness Ullett (cyber).

Q. **What were the major causes of the $67.6 million increase in DP&L and DPL Energy environmental plant additions from the beginning of the Base Period (June 1, 2002) and the end of the Base Period (May 31, 2003)?**

A. For DP&L, the plant additions at Miami Fort Station ($29 million) and East Bend Station ($19 million) primarily for Selective Catalytic Reduction (SCR) Equipment accounted for 92.4% of the increase in environmental plant additions during the period. A detailed listing of the entire $67.6 million in gross plant increases can be found in Workpaper Base WPB-2.1a.

Q. **What was the cause of the $15.6 million increase in environmental plant additions for DPL Energy during the same time period?**

A. Two units at the Darby Station ($5.2 million) and four units at the Tait Station ($10.4 million) that went into service in June 2002 accounted for the entire amount of additions during the period.

Q. **Does the Company seek to recover the increased cost in these major environmental plant additions of $67.6 million in this proceeding?**

A. No. Since these environmental plant additions, which were necessary to meet environmental requirements, as described in Company Witness Wright's testimony, occurred during the base period, the Company is not seeking to recover these increased costs in this proceeding.

Q. **Do you sponsor any additional base period workpapers?**

A. Yes. I sponsor Base WPB-4.1a, which contains actual fuel stock balances by plant and Base WPB-4.3a, which contains actual environmental instrument balances. This data comes from our accounting records. These workpapers support Schedule Base B-4.1 and Schedule Base B-4.3, respectively, both sponsored by Company Witness Stephenson.

D. Explanation Of Test Period Schedules

Q. What is shown on Schedule Test B-1?

A. Schedule Test B-1 is a summary of the various rate base items for the test period date certain at March 31, 2005. The data reflects actuals through December 31, 2004 with estimates for January through March 2005. The sources for the various schedule components are shown under the source column, namely Schedule Test B-2 line 2 for Plant in Service, Schedule Test B-3 line 57 for Reserve for Accumulated Depreciation, Schedule Test B-4 line 10 for Working Capital Allowance and Schedule Test B-5 line 40 for Deferred Taxes.

Q. What is shown on Schedule Test B-2?

A. Schedule Test B-2 depicts Environmental Production Plant in Service as of March 31, 2005. The source for this data is Schedule Test B-2.1 line 56.

Q. What is shown on Schedule Test B-2.1?

A. This schedule shows the Environmental Plant in Service by accounts at March 31, 2005.

Q. What is the source of this data?

A. The data was taken from the various plant accounts on Schedule Test B-2.2, Gross Additions and Retirements.

Q. **What is shown on Schedule Test B-2.2?**

A. Schedule Test B-2.2 shows the beginning balance by plant account and station and the associated gross additions and retirements from June 1, 2003 (May 31, 2003 Base Period valuation date for environmental plant) through March 31, 2005. Monthly additions and retirements were identified using actual data for June 1, 2003 through December 2004 with estimated data utilized from January 2005 through March 2005. This data was summarized to get the total period gross additions and retirements. The ending balance at March 31, 2005 is the source for Schedule Test B-2.1 Environmental Plant at March 31, 2005, the date certain for the Test Period. This information will be updated with January 2005 through March 2005 actual figures as part of the 60-day update in this proceeding.

Q. **What is contained on Schedule Test B-3?**

A. Schedule Test B-3 depicts the estimated Environmental Reserve for Accumulated Depreciation for DP&L and DPL Energy by account at March 31, 2005. It will be updated with actual figures through March 31, 2005 as part of the 60-day update in this proceeding.

Q. **How were the account balances determined?**

A. The Environmental Reserve for Accumulated Depreciation at May 31, 2003, the plant in service measuring date for the base period in this proceeding, was updated to reflect monthly depreciation expense from June 2003 through December 2004 (actuals), and January 2005 through March 2005 (estimates). Retirements for the same time frame were deducted from the reserve. See Workpapers Test WPB-3.1 and Test WPB-3.2 for further details of these computations for DP&L and DPL Energy, which I adopt as part of my testimony.

Q. What is shown on Schedule Test C-1?

A. Schedule Test C-1 is a summary schedule that shows total Fuel and Emission Expenses, Purchased Power Fuel and Emission Expenses, Other Operation and Maintenance Expenses, Depreciation Expense, Taxes Other Than Income Taxes and Income Taxes. The sources of this data are Schedules Test C-1.1, Test C-1.2, Test C-1.3, Test C-1.4, Test C-1.5 and Test C-1.6.

Q. What is depicted on Schedule Test C-1.1?

A. Schedule Test C-1.1 shows Environmental O&M and Fuel Expenses by account for the period October 2004 through September 2005. Actual results for the October 2004 through December 2004 were used with the remaining months of January 2005 through September 2005 being forecasted. Actual data for January 2005 through March 2005 will be included with the 60-day update in this proceeding.

Q. What are the sources of the data on this Schedule?

A. Actual fuel data for October through December 2004 were obtained from the Company's general ledger system. The Purchased Power (fuel and emissions only) data was furnished by Company Witness Stephenson as detailed on Schedule Test C-1.2. The actual and forecasted O&M costs for generation plants operated by Cinergy and AEP were furnished by those companies and were then allocated to DP&L's share. The actual and forecasted O&M costs for DP&L and DPL Energy were obtained from company records. Workpaper Test WPC-1.1a contains actual and forecasted amounts by account and station for the 12 months ended September 2005. The depreciation expense for DP&L and DPL Energy was calculated based on monthly environmental plant account balances throughout the October 2004 through September 2005 period. See Workpaper Test WPC-1.1b. Property insurance for the period was allocated based upon the relationship of environmental plant to total plant at December 31, 2003.

Q. Are there any other test period workpapers that you sponsor?

A. Yes. I sponsor the actual data contained on Workpaper Test WPB-4.1a and Workpaper Test WPB-4.3a, which addresses fuel stock and emission instrument balances. I also sponsor all of the data relating to emission fees on Workpaper WPB-4.3a line 1. In addition, I sponsor the actual portion of the data contained on Workpaper Test WPC-1.2a (Accounts 501 and 547 – Fuel Expense), Workpaper Test WPC-1.2a1 (Fuel Expense by Plant), Workpaper Test WPC-1.2b (Account 509 – Emission Allowances) and Workpaper Test WPC-1.2c (Account 555 – Fuel and Emissions Expenses in POLR Purchased Power – Test Period, Columns B, C and D on page 2 of 2).

Q. Have you found that there were any corrections necessary to the workpapers and schedules that you sponsor or co-sponsor?

A. Yes. I changed Schedule Base B-1 line 5 (Deferred Taxes associated with Pollution Control). Due to an error in bringing the Deferred Taxes forward from Schedule Base B-5 line 40, the Column (B) amount of $77,131,418 should be shown as a credit (that is, as a reduction to Rate Base) and not a debit, or increase in Rate Base. Schedule Test B-1 line 5 (Deferred Taxes associated with Pollution Control) also changed for the same reason, Schedule Test B-5 line 40, the Column (B) amount of $92,989,094 should be shown as a credit. In addition, corrections were made to Workpaper Base WPC-1.1b, Depreciation Expense Calculation – Miami Fort page 2 of 14. Line 3, Columns (D), (F), (H), (J), (L) and Line 10, Columns (O), (Q), (S), (U), (W) and (Y) were revised to reflect correct Plant Account Balances. The Associated Depreciation Expense (Line 3, Columns (E), (G), (I), (K), (M) and Line 10, Columns (P), (R), (T), (V), (X) and (Z)) and the 12 Months Depreciation Expense, Line 10, Column (AA), reflects these changes. Depreciation Expense Calculation – Stuart Station – page 7 of 14, Line 3, Column (D) and Line 10, Column (S) were revised to reflect the correct plant balances, the Associated Depreciation Expense (Line 3, Column (E) and Line 10, Column (T)) and the 12 Months Depreciation Expense Line 10, Column (AA). These Depreciation Expense Calculation changes increased Base Period depreciation expense by $12,173. I also corrected Workpaper Base WPC-1.1a Line 2, Column (I) and Line 18, Column (L) to correct input errors. This reduced O&M expense for the 501 and 921 accounts by $3 and $2,998, respectively. All of these changes were reflected in the Company's amended Schedules and Workpapers filed on April 15, 2005.

III. CONCLUSION

Q. Please summarize your testimony.

A. In summary, the base period and test period schedules that I sponsor were derived from the Company's accounting records along with information supplied by its partners, Cinergy and AEP, which jointly own generating stations with DP&L. The environmental capital plus the environmental O&M and depreciation expenses for both periods were taken from those sources and are an accurate and reasonable depiction of these costs.

Q. What are the primary reasons for the $150.9 million increase in environmental plant from May 31, 2003 to March 31, 2005?

A. The primary causes of the increase are the seven SCR systems projects which were installed at the Zimmer (1), Miami Fort (1), Killen (1) and Stuart (4) Stations. The cost of these seven major projects totaled $148 million or over 98% of the entire increase. These additions were necessary to meet the changing and more stringent environmental emission requirements described by Company Witness Wright.

Q. What are the primary causes of the increase in environmental O&M costs, excluding fuel, purchased power (fuel and emissions) and emission allowances over the base period?

A. The primary causes of the increase of $9.7 million in these costs were the result of the installation of the seven SCR systems and other cost increases during the time frame. Costs that increased due to these installations were the increased use of ammonia and operation and maintenance of the SCR units for NO_x removal. In addition, higher lime costs to operate the scrubbers at East Bend and Zimmer stations for SO_2 removal and SO_3 mitigation expenses contributed to the overall increase.

Depreciation expense increased $5 million over the base period directly as a result of the installation of the seven SCR systems and other minor environmental plant additions.

Q. Were there any increases/decreases in physical and cyber security costs in the test period?

A. Yes. Physical security costs increased $11,208 while cyber security costs decreased by $4,064. Workpaper Test WPC-1.1c (physical) and Workpaper Test WPC-1.1d (cyber) support the test period amounts. I co-sponsor these workpapers with Company Witnesses Guerriero (physical) and Ullett (cyber).

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. 05-276-EL-AIR

DIRECT TESTIMONY
OF CHRIS T. HERGENRATHER

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

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

CHRIS T. HERGENRATHER

ON BEHALF OF
THE DAYTON POWER & LIGHT COMPANY

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I. INTRODUCTION

Q. Would you please state your name and business address for the record?

A. My name is Chris T. Hergenrather. 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") as Tax Manager.

Q. Would you describe briefly your educational and business background.

A. I am a 1981 graduate of Wright State University with a Bachelor of Science in Accounting and received a Masters of Business Administration in Management in 1988, also from Wright State University. I am also a member of the Edison Electric Institute's Taxation Subcommittee. I joined DP&L in September 1981 and worked until 1992 in various accounting positions. In February 1992 I moved into DP&L's Tax Department in a staff position. In 2000, I was promoted to Supervisor and in 2002 was promoted to Tax Manager. In my position I am responsible for matters related to the Company's tax liabilities.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to explain (1) the calculation of the gross revenue conversion factor; (2) changes in tax laws that have impacted DP&L between the base period and test period; and (3) changes in DP&L's deferred taxes due to changes in DP&L's environmental rate base between the base period and the test period.

Q. What schedules and workpapers do you sponsor?

A. I am sponsoring Summary Schedule A-4, Schedule Base B-5, Workpaper Base WPB-5.1, Workpaper Base WPB-5.2, Schedule Base C-1.3, Schedule Test B-5, Workpaper Test WPB-5.1, Workpaper Test WPB-5.2, Schedule Test C-1.3 and Schedule Test C-1.4 These schedules and workpapers were prepared based on information obtained from DP&L's audited financial records and are accurate and reasonable.

II. GROSS REVENUE CONVERSION FACTOR

Q. Can you explain the purpose of a gross revenue conversion factor?

A. Yes. DP&L, like most businesses, has uncollectible accounts and pays taxes on its profits. The purpose of a gross revenue conversion factor is to determine how much total revenue DP&L must receive so that DP&L will receive its revenue requirements after uncollectibles and taxes are accounted for. DP&L's revenue requirement is thus multiplied by the gross revenue conversion factor to determine the total revenue DP&L is entitled to receive.

Q. Can you explain how you calculated the gross revenue conversion factor in this matter?

A. Yes. That calculation is shown on Summary Schedule A-4. The gross revenue conversion factor is used to determine incremental revenue requirements by identifying and quantifying incremental costs and tax changes that vary with revenue. DP&L's historic rate of uncollectible accounts and applicable statutory income tax rates are used in the calculations and all tax percentages include the effects of other taxes on the incremental rate.

Q. Please describe why Summary Schedule A-4 shows two different gross revenue conversion factors.

A. The gross revenue conversion factor is used on Summary Schedule A-1 to increase the Net Qualified Increases to the Jurisdictional RSS Revenue Requirement. The O&M/Debt gross revenue conversion factor excludes the tax components of the factor, recognizing that the items included in the O&M/Debt Net Qualified Increases are deductible for tax purposes. This means that for each incremental dollar of revenue required there is an offsetting dollar of deduction and no additional revenues are needed to cover incremental increases in tax. The O&M/Debt gross revenue conversion factor compensates only for uncollectible expense. The Equity Net Qualified Increases are not deductible for tax purposes so that each incremental dollar of revenue required will result in additional income tax. Therefore, the Equity gross revenue conversion factor is needed to increase the Jurisdictional RSS Revenue Requirement to compensate for the incremental income tax in addition to the uncollectible expense

III. CHANGES IN TAX LAWS AND REGULATIONS

Q. Have there been changes in tax laws or regulations since May 31, 2003 that have caused DP&L or its affiliates to experience changes in tax expenses associated with their generation facilities?

A. Yes. I have identified two changes in tax laws that have impacted the taxes that DP&L and its affiliates pay related to generation facilities. First, statutory changes are made each year to many of the tax rates assessed against DP&L's personal property. Second, in October 2004, President Bush signed the American Jobs Creation Act of 2004 (AJCA) into law. The AJCA created a new deduction effective for 2005 for domestic production activities. Electric production is specifically identified in the law as an activity that is eligible for the deduction.

Q. Can you explain how you quantified the change to DP&L's expenses due to changes in personal property tax rates?

A. Yes. My calculations are shown on Schedule Test C-1.3 and Schedule Base C-1.3. Those schedules quantify the effect that changing tax rates have had on DP&L's expenses between the base period and the test period. A comparison of those schedules shows that DP&L has experienced increased expenses of approximately $107,000 between the base and test periods due to changes in tax rates for both DP&L and DPL Energy. The total expense figures from those two schedules have been incorporated in Schedule Test C-1 and Schedule Base C-1, respectively.

Q. Can you explain how you quantified the change to DP&L's expenses due to the American Jobs Creation Act?

A. Yes. That calculation is shown on Schedule Test C-1.4. That schedule computes a revenue adjustment related to the domestic production deduction introduced in the 2004 American Jobs Creation Act enacted on October 22, 2004. This deduction reduces DP&L's 2005 federal tax liability by 3% of its domestic production taxable income, with certain limitations. The annual 2005 production taxable income is allocated to the 9 months of 2005 in the test period. (The deduction was not available during the base period so no corresponding base period schedule was necessary.) As shown on Schedule Test C-1, the net effect of the American Jobs Creation Act is to reduce test period expenses by approximately $1.3 million.

IV. DEFERRED TAXES

Q. Can you explain what deferred taxes are and how they affect DP&L's rate base?

A. Yes. Deferred taxes represent the tax effect of timing differences between the recognition of income and deductions for tax purposes and when income and deductions are recognized for book purposes. Generally, Financial Accounting Standards Board Statement No. 109 requires deferred taxes to be measured by the difference between the net tax basis (gross tax asset or liability less accumulated tax depreciation) and the net book basis (gross book asset or liability less accumulated book depreciation). In our case, deferred taxes arise due to the fact that tax laws generally permit a utility to depreciate its assets at a faster rate than the utility can depreciate those assets on its regulatory books. The accelerated tax depreciation permits a utility to recognize increased expenses on its tax returns, and thus pay lower taxes. Since a utility has received the benefit of paying lower taxes, that benefit is used to reduce the utility's rate base.

Q. Has DP&L experienced a change in deferred taxes on the environmental assets included in DP&L's rate base between the base period and the test period?

A. Yes. As explained in Amy Wright's testimony, DP&L has put new environmental equipment into service between the base period and the test period. DP&L has thus been depreciating that equipment on its tax books at a faster rate than DP&L has depreciated that equipment on its regulatory books. As explained above, that accelerated depreciation creates deferred taxes.

Q. Can you describe how you calculated the change in deferred taxes that DP&L experienced between the base period and the test period?

A. Yes. That calculation is shown on Schedule Test B-5 and Schedule Base B-5. Those schedules compute the deferred tax balances related to pollution control property. The pollution control deferred taxes for the base period are used to adjust the pollution control rate base on Schedule Test B-1 and Schedule Base B-1.

Q. How did you determine the test period and base period deferred taxes for pollution control property?

A. As shown on Schedule Test B-5 and Schedule Base B-5, I calculated the difference between the net book basis and net tax basis and applied the currently enacted statutory tax rates (both federal and state) to calculate the deferred taxes for DPL Energy and for DP&L. DPL Energy and DP&L do not maintain deferred tax balances for pollution control property separately. Therefore, the first step is to calculate the net book basis and net tax basis of total production plant for each entity. DPL Energy and DP&L do not maintain all book and tax basis information on a monthly basis so allocations were made to state the net book and net tax basis to the end of the base period. Then the related deferred taxes were calculated using the current tax rates. Finally, the deferred taxes were allocated to pollution control property based on the percentage of pollution control property to total production plant for each entity.

Q. Do you sponsor Workpaper Test WPB-5.1 and Workpaper Base WPB-5.1?

A. Yes. Those workpapers support Schedule Test B-5 and Schedule Base B-5, respectively, by calculating pollution control property as a percentage of total production plant for both DP&L and DPL Energy. Those workpapers also calculate the combined federal and state statutory tax rates.

Q. Do you sponsor Workpaper Test WPB-5.2?

A. Yes. That workpaper supports Schedule Test B-5 by calculating the tax reserve adjustments for January 2005 through March 2005 to arrive at the net tax basis at the date certain. Schedule Test B-5 shows adjustments to book and tax basis and book reserves that are based on the DP&L capital budget approved by the Board of Directors. Workpaper Test WPB-5.2 computes the tax reserve adjustments required to state the tax reserve as of the date certain. For DPL Energy, the tax reserves were allocated to the period based on $3/12^{th}$ (3 month/12 months) of the estimated annual 2005 tax depreciation expense for production property placed in service by December 31, 2004. In addition, the 2005 expenses for the projected 2005 gross plant additions from the approved capital budget were depreciated using a 15 year Modified Accelerated Cost Recovery System ("MACRS") depreciation schedule. This 2005 depreciation expense was allocated to the three months needed to reach the date certain. For DP&L, the tax reserve adjustments were calculated at $3/12^{th}$ (3 months/12 months) of the estimated 2005 tax depreciation as projected in our Acufile Tax Depreciation system based on production plant placed in service by December 31, 2004. In addition, the 2005 depreciation expense for the projected 2005 gross plant additions from the approved capital budget were depreciated using a 20 year MACRS depreciation schedule. This 2005 depreciation expense was allocated to the three months needed to reach the date certain.

Q. **Do you sponsor Workpaper Base WPB-5.2?**

A. Yes. That workpaper supports Schedule Base B-5 by calculating the book and tax basis and reserve adjustments for January 2003 through May 2003 to arrive at the net book and net tax basis at the end of the base period. For DPL Energy, there were no book or tax basis additions during the period. The book and tax reserves were allocated to the period based on $5/12^{th}$ of the change in the reserves between December 2002 and December 2003. (The $5/12^{th}$ allocator was used to allocate twelve months of 2003 data to the five-month January 2003 to May 2003 period.) For DP&L, the book basis and book reserve were extracted from our Oracle Fixed Assets system. The tax basis and tax reserve adjustments were calculated at $5/12^{th}$ of the change in the tax basis and tax reserves between December 2002 and December 2003 as reported in our Acufile Tax Depreciation system.

Q. **What is the net effect the changes in deferred taxes on rate base in this matter?**

A. As shown on Summary Schedule A-2, due to increases in DP&L's environmental rate base between the base and test periods, deferred taxes increased from about $77.1 million to $93 million between the periods. That amounts to a net increase, after applying the jurisdictional allocator, of about $14.9 million. Since deferred taxes are subtracted from rate base, the $14.9 million increase in deferred taxes causes a corresponding $14.9 million decrease to rate base between the periods.

V. CONCLUSION

Q. Please summarize your testimony.

A. This testimony explains three points: (1) the calculation of DP&L's gross revenue conversion factor; (2) the impact that changes in tax laws have had on DP&L between the base period and the test period; and (3) the changes in deferred taxes on environmental rate base between the base period and the test period.

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. 05-276-EL-AIR

DIRECT TESTIMONY
OF JEFF D. MAKHOLM, PH.D

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

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I. INTRODUCTION

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q. Please describe your academic background.

A. I have M.A. and Ph.D degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience.

A. My work centers on economic issues involving pricing, regulation and market issues for the natural gas and electricity industries, among others. My consulting work includes the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state, federal and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work pertaining to the gas industry, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Regarding rate of return and utility financing questions specifically, I have testified for electric, natural gas, water and telecommunications utility clients before state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Illinois, Indiana, Maine, and Connecticut, as well as before the Federal Energy Regulatory Commission ("FERC"). My current curriculum vitae, which more fully details my educational and consulting experience, is provided as **Exhibit JDM-1**.

Q. Does your testimony in this proceeding determine the cost of common equity, and therefore the fair rate of return on common equity, on behalf of The Dayton Power and Light Company ("DP&L" or the "Company")?

A. Yes. This cost of common equity will be used by the Company to calculate its revenue requirements for retail ratemaking purposes. **Exhibits JDM-2, JDM-3,** and **JDM-4** explain and support my use of the Discounted Cash Flow (DCF) analysis, **Exhibits JDM-5** and **JDM-6** summarize my comparable group selection process, and the balance of my exhibits presents my DCF and CAPM analyses as well as an explanation of the risks that electricity distributors face in the current environment. I use the projected actual capital structure ratios, long term debt and preferred equity, that would be applicable for DP&L at the time that new rates would go into effect, as shown on **Exhibit JDM-7.**

Q. Please summarize your conclusion as to the fair rate of return on common equity for DP&L.

A. The fair rate of return on common equity I recommend and conclude is reasonable for DP&L is **10.39 percent**, as summarized on **Exhibit JDM-7**. My recommendation is based on a Discounted Cash Flow (DCF) analysis of ten comparable electric utilities.

Q. What is the required overall rate of return for a firm?

A. The required rate of return for a firm is the firm's weighted average overall cost of capital ("WACC"). The WACC is the sum of the costs of the component parts of the capital structure, *i.e.*, debt and common equity, weighted by their relative proportions in the capital structure.

On **Exhibit JDM-7**, I present the capital structure and the cost of capital components that are appropriate for the companies. The overall cost of capital for DP&L is **8.78 percent**.

Q. How do you characterize the nature of your rate of return testimony?

A. One of the most important goals of my rate of return testimony is to minimize the amount of subjectivity in the determination of the fair rate of return. I view subjectivity as the principal source of contention in the calculation of the rate of return in utilities' rate cases. This subjectivity has four sources: (1) lack of attention to detail in employing the methods provided by decades of work in the field of theoretical finance; (2) a proliferation of quantitative approaches to determining the cost of capital, under the dubious premise that the use of *more methods*—no matter how shaky the foundation for each—provides better rate of return evidence; (3) insufficient candor on the part of analysts regarding their application of objective, reproducible standards or personal judgment; and finally, (4) subjective adjustments to the results of empirical analyses.

Subjectivity creates a regulatory atmosphere in which it is very difficult, if not impossible, to resolve the contentious issues surrounding the determination of a utility's cost of equity and therefore setting of the fair rate of return. Most, if not all, other rate case issues have objective standards (*e.g.*, legal, policy, empirical) upon which to measure the value of evidence presented in rate cases. Only the process of finding the cost of equity and fair rate of return seems immune to measurement by such standards. I have attached, as **Exhibit JDM-2**, an article that discusses some of the problems associated with rate of return investigations.[1]

To avoid contention, I make every attempt to avoid injecting subjectivity into the calculation of the fair rate of return. I am very careful in my choice of models and data. I also resist performing a multitude of ROE calculations, because I conclude that this

[1] *See* Jeff D. Makholm, "In Defense of the 'Gold Standard,'" *Public Utilities Fortnightly*, May 15, 2003, pp. 12-18.

approach obscures rather than clarifies. When the use of judgment is unavoidable, I explain the basis for my judgment. Finally, I avoid making subjective "risk" adjustments that do not have a solid and empirically verifiable financial basis. Rate of return analysis suffers widely from a fog of *ad hoc* adjustments that are impossible to verify empirically or theoretically.

As a result, the standards to which I hold my evidence, as well as that of others, are: (1) clarity; (2) theoretical support; (3) empirical objectivity; (4) stability (*i.e.*, not producing widely disparate results); and (5) the ability to reproduce (*i.e.*, allowing others to readily re-compute my results). My evidence for DP&L reflects my desire to hold to these five standards of evidence.

Q. Do you engage in detailed discussions of general economic trends?

A. No. I do not include much discussion of general economic trends (Federal Reserve policy, etc.) that some other witnesses provide. Such discussions do not inform us regarding what *investors* believe is going to happen in the future. In order to gauge investor expectations, we must resort to the financial models that have become familiar in rate of return proceedings. These models all employ the markets for utility securities as the source of investors' verdicts regarding the cost of capital.

The markets for utility securities provide the only evidence on what investors require as a return on the money they invest in utilities, and the financial models that currently exist put evidence from those markets in its proper context. The utilities security markets use general economic information in the most efficient way. It is neither efficient nor appropriate for me to render a verdict on the future of markets when the law requires me to try to reflect what *investors* think. My task should be to combine *investors'* verdicts on the value of utility securities and sound financial models to determine the fair rate of return in the most direct and objective way possible.

Q. How does your evidence in this case reflect your desire to pursue objective, reliable and reproducible results?

A. I pursue these goals in two main ways: (1) I use those financial models and methods that permit the greatest objectivity; and (2) I make use of comparable company groups (also known as "proxy groups") to draw more reliable conclusions about investors' expectations.

Q. Please discuss how the selection of financial models and methods facilitates the greatest objectivity in finding the cost of equity and fair rate of return.

A. Although much time is devoted to discussions of various techniques for finding the cost of equity and fair rate of return, little discussion is usually devoted to determining whether these techniques are practical in the rate case setting and whether they are capable of limiting the scope for contention in rate cases. There are two main attributes of financial models that help on both counts: (1) the models should be strictly forward-looking; and (2) the models should offer an objective way of dealing with the uncertainty that is inherent in gauging investors' future expectations.

Q. Why is a forward-looking perspective important?

A. Investors look toward the future when they demand compensation for the use of their money. Therefore, the cost of capital is a forward-looking concept. However, there are few ways to look into the future, particularly from the perspective of what *investors* expect to occur. Those strategies are generally indirect—we look at stock prices or interest rates to gauge these expectations. This indirection is precisely why the field of finance has developed models like the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM"). Those models use the limited types of information we *can observe* to draw conclusions about *unobservable* investor expectations of the future.

A forward focus and the use of valid financial models reduce the types of information that can help determine the cost of capital. Only a limited amount of information, either observed (such as stock prices and interest rates) or produced by disinterested sources (forecasts from widely distributed financial advisory services), fits our needs in the context of the available financial models. The use of this information limits the sources of contention in rate cases, minimizing the role of subjective judgment and restricting the ability to bias the results.

If we abandon a strict forward focus we open the floodgates to a sea of information that: (1) cannot help to determine today's investors' expectations; and (2) can be used selectively to bias rate of return results. With *any* backward-looking method of determining the rate of return, we can greatly alter the results simply by changing the historical time period used in our analysis (*e.g.*, two years, five years, fifty years). Furthermore, we abandon financial theory and therefore have no guide to the proper time. Any period seems as good as any other, and we cannot resolve this matter in the context of a rate case.

Q. Why is it important to use financial theories that allow an objective way of dealing with the uncertainty involved with gauging investors' expectations?

A. Gauging investors' future expectations involves an unavoidable element of uncertainty. There is no direct and reliable way to learn today's cost of capital for the utility in question. Our indirect methods use models with simplifying assumptions and require data that may not always be accurate or timely. That is, given a model's simplifying assumptions, the data used may cause us to think that investors are overly ambitious for one company and the reverse for another. The models we use should resolve this uncertainty objectively, because we have little use for a financial model that leaves us with a 250 basis point range containing the cost of capital and no way to choose within it.

This indeed is the practical criterion that separates the usefulness of the two most popular financial theories used in rate cases—the DCF and the CAPM. The DCF renders a cost of capital estimate for each company in a proxy group. Some might seem a bit high and others a bit low, but the individual company results have objective "measures of central tendency," such as means and medians. The CAPM, on the other hand, is the sum of two components: (1) a company-specific risk premium, and (2) a "risk-free" rate applicable to all companies.

One can choose from a variety of risk-free rates (*e.g.*, long-term/short-term) for which theory gives us no unambiguous guide.

Furthermore, because the same risk-free rate applies as an additive term to all companies' cost of equity estimates, no measure of central tendency results. In short, we cannot resolve the question of uncertainty surrounding short-term versus long-term rates by repeated sampling. In the end, the analyst must choose a risk-free rate that drives the results—precisely the type of choice that limits the model's objectivity and effectiveness. Indeed, this limitation is the principal reason that I avoid the CAPM as a primary ROE method.

Q. What specific issues do you address in your testimony?

A. First, I summarize my findings and discuss the meaning of the term "fair rate of return" on equity. Second, I describe the DCF method that constitutes my principal method for determining that return. Third, I present my cost of common equity recommendation for DP&L's regulated electricity operations. I base my recommendation on a group of companies whose levels of risk are comparable to DP&L's: a ten-company electric and combination electric and gas group. Fourth, I check the reasonableness of my recommendation using a comparison of allowed returns in other jurisdictions. Fifth, I use the CAPM method to also check the reasonableness of my recommendation. Sixth, I discuss the business risk that electric utilities face in the correct environment. Finally, I discuss the appropriate capital structure, embedded costs of preferred stock and debt, and the recommended overall cost of capital for DP&L.

II. SUMMARY AND BACKGROUND TO THE DETERMINATION OF A FAIR RATE OF RETURN ON EQUITY

Q. Please summarize your conclusions regarding the fair rate of return on common equity for DP&L's electricity operations.

A. I recommend a fair rate of return on common equity of **10.39 percent** as summarized on **Exhibit JDM-7.** I base my recommendation on the results of a DCF analysis performed on a proxy group of U.S. utilities that are comparable to DP&L's electric operations.

I recommend an overall cost of capital of **8.78 percent**, as presented on **Exhibit JDM-7.**

A. Background to the Determination of the Fair Rate of Return on Common Equity

Q. What do you mean by "fair rate of return on common equity?"

A. The essence of traditional public utility ratemaking—the "regulatory compact"—has been that utilities like DP&L have been protected by franchise against certain specific and limited types of competition. In return, the utility has accepted the obligation to provide service on just and reasonable terms. The utility has also accepted the duty to reasonably anticipate the future needs of its customers and to make whatever investments it judges necessary in order to meet those needs as efficiently as possible. Finally, the utility has accepted that prices would be set so as to recoup operating costs plus a reasonable profit. For a public utility, reasonable profit, under the law and in the financial world, has been defined as a rate of return sufficient to attract capital.

The capital attraction—or "opportunity cost"—standard has been key in determining the fair rate of return for public utilities. When investors make their funds available to a utility, they forego the option to use those funds for another purpose (either current consumption or another investment). They also put their funds at some risk. In return for foregoing current consumption and incurring risk, utility investors require a return on their funds. This return to investors is a cost to the utility—the "*cost of capital.*" In order for the utility to compensate its investors adequately for the current consumption foregone and the risk incurred, the utility must be allowed, as a component of its rates for service, a *fair rate of return* that covers its cost of capital.

Q. Does the way you have just defined the concept of fair rate of return on equity comport with its traditional definition?

A. Yes. The United States Supreme Court established the traditional standard for a fair and reasonable return in its *Hope* decision (*Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)):

> …the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks.* That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital.* (Emphasis added.)

This often-quoted passage from the *Hope* decision, besides providing a legal standard for determining the fair rate of return, comports precisely with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital.

In an earlier case, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679, 693 (1923), the Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Furthermore, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fourteenth Amendment.

> Rates, which are not sufficient to yield a reasonable return on the value of the property used at the time it is being so used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment.

Q. Has the traditional regulatory compact changed over time?

A. The return that investors are due on their invested capital has not changed. The extent to which utility operations are regulated has changed.

Q. Please explain.

A. Deregulation has been implemented in many industries throughout many countries in the past twenty years. The electric and gas industries have not been immune to these changes. Technological changes and increased competitive pressures have made restructuring possible in the industry, and successful deregulation in other industries has created demand for it.

Most states have begun to consider how to restructure their electric and gas industries; a number of states have already introduced retail choice and many states are well on their way. Pursuant to Ohio law, the Public Utilities Commission of Ohio (the Commission) has opened electricity generation to competition and has provided for retail competition in the electricity commodity, while continuing to regulate electric transmission and distribution and provide for a standard offer product.

Q. Does the traditional concept of fair rate of return apply to all of the capital raised by the utility from investors, or just the common equity component?

A. It applies to all of the capital. This includes a company's common stock equity, preferred stock equity and debt.

Q. How are the individual fair returns or costs of capital pertaining to debt and preferred stock determined in a rate case?

A. Fixed payment obligations accompany both debt and preferred stock: interest on the former, preferred dividends on the latter. Calculating the dollars needed to cover interest or preferred stock dividend payments currently or over the period of time in which the rates in question for a utility will be in effect is not difficult. The *embedded* cost of debt and preferred stock proceeds directly from these calculations.

I highlight the word "embedded" because, for debt and preferred equity, all that we need in a base rate case is the embedded cost of these financial instruments (the payments to investors proceeding from existing agreements accompanying the existing bonds and preferred shares). Thus, parties in rate cases seldom significantly disagree over the embedded cost of debt and preferred equity capital. One can compare the promised interest and preferred dividend payments with the company's proceeds from the sale of those securities. The current market is irrelevant for such embedded cost calculations.

Q. Can a current (as opposed to embedded) cost of debt and preferred equity capital be observed in the market?

A. Yes. Since we know the schedule of interest and preferred stock dividends, and since we know the current market price for these financial instruments (a bond or share of preferred stock), we can observe the current (as opposed to embedded) cost of capital for both types of financing. The current cost of debt and preferred stock capital, reflecting investors' required return, is the discount rate that equates the present value of the known stream of interest (and principal) payments, or preferred dividend payments, with the observed price of those securities.

In other words, a relatively straightforward way to determine the current cost of debt and preferred equity securities is to observe the known market price and the known stream of interest and preferred dividend payments and to calculate the discount rate that equates the two. The derived discount rate is equivalent to the current cost of debt and preferred equity capital.

Q. Can we calculate the current cost of common equity capital in the same way?

A. No. An essential component to that calculation is knowledge of the (fixed) interest and preferred stock dividend payments. Dividend payments on common stock equity are not fixed, nor is their growth rate measured with certainty. They are generally expected to grow as the company in question grows. This growth rate is not observable—the growth rate is embodied in unobservable equity investor expectations regarding the future performance of the company in question. Because this growth rate is not observable, the future stream of dividend payments is not known. There is therefore no known stream of payments that may be used directly to find the discount rate equating the present value of the future stream of dividend payments with the observed common stock price.

Q. How can we estimate the cost of common equity in DP&L's capital structure?

A. One way to estimate the cost of equity capital (and generally the most popular method among regulatory commissions) is to determine the stream of common dividends that investors expect. This determination entails observing the current dividend and engaging in the difficult task of estimating what investors expect regarding the growth in that dividend. After the growth expected by investors is estimated, the cost of common equity can be calculated by equating the present value of the estimated stream of dividend payments with the observed common stock price. The calculated cost of capital resulting from this method is entirely dependent on the quality and dependability of the estimates of investor expectations regarding dividend growth. This type of estimation, which I shall later describe in detail as the DCF method, is the method I use to estimate the fair rate of return for DP&L.

B. Estimating the Cost of Equity Capital

Q. How do you determine the fair rate of return on common equity for DP&L that is consistent with the standards you described and that addresses the difficulties inherent in estimating the cost of equity capital?

A. Estimating the cost of capital involves theoretical and empirical components. I focus on both of these aspects in my cost of capital calculation.

The theoretical component relies on the standard financial literature to develop cost of capital methods that are consistent with what we know and observe about the way that financial markets work. All of the cost of capital models that appear in the financial literature result from theoretical investigations. The most important theoretical consideration when determining the cost of capital for DP&L is to employ a method that provides an accurate reflection of the market for the DPL Inc. common stock.

The empirical component includes the collection of the data to be used with the theoretical cost of capital methods. The most important empirical consideration is to gather data that are: (1) consistent with the theoretical models employed; (2) timely; and (3) unbiased. It is also important that the calculations made with the empirical data be reliable and stable. In other words, the resulting cost of capital measure should not be highly sensitive to minor or judgmental changes in the type or source of the data used.

Q. What theoretical method do you use in your evaluation of DP&L's cost of capital?

A. As I mentioned in the previous section, I employ the DCF method. The DCF method makes use of the relationship between the current stock price and the expected future stream of dividends in order to calculate investors' estimated discount rate, or cost of equity. The DCF method has a long history of being used to derive the cost of equity for both regulatory and market investment purposes. It is a sound, reliable, easy-to-understand and easy-to-reproduce method for determining the fair rate of return. Furthermore, it is unique among rate of return determination methods in that the model's results become stable and reliable when it is applied to a group of comparable utilities.

III. THE DCF METHOD

A. A Description of the DCF Method

Q. Please describe the DCF method.

A. The DCF method is used to estimate the cost of common stock equity by determining the present value of all future income expected to be received from a share of common stock. As such, the DCF method is the common stock equity analog to the way in which debt and preferred stock equity cost rates are calculated. With the DCF method, the cost of common stock equity is computed as the discount rate that equates a stock's current observed market value with the present value of all future expected returns from holding the common stock (*i.e.*, dividends and capital gains). The prevailing common stock price is assumed to reflect investors' expectations of the value of common stock, including future dividends and price appreciation.

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[2] The research performed by subsequent writers (including Gordon himself) resulted in the equation known as the "Periodic" DCF model. The "Periodic" DCF model generally expresses k_e, the cost of the common stock equity portion of total capital, as a relationship between the prevailing price of common stock equity, P_0, current dividends, D_0, and the dividend growth rate, g. Following is a formal statement of the "Periodic" DCF model. The derivation of this model appears in **Exhibit JDM-3** of my testimony.

$$k_e = \frac{D_0 * (1+g)}{P_0} + g$$

$$k_e = \frac{D_1}{P_0} + g$$

[2] See: Myron J. Gordon, *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

Where: (1)

P_0	=	price of stock
D_0	=	previous dividend paid
k_e	=	cost of equity
g	=	dividend growth rate

This "periodic" or annual version of the DCF model has been very popular in regulatory rate of return proceedings. In order to use the model properly, however, it is important to reflect accurately how dividends are paid and how they grow. This model has two significant abstractions from the reality of dividend payments. First, it assumes that dividends are paid annually; and second, it assumes that dividends grow continuously from period to period. In fact, most utilities pay dividends quarterly and increase their dividends only once a year, if at all.

A different version of the DCF model avoids these abstractions. Specifically, the "Quarterly" DCF model recognizes quarterly dividend payments and allows these payments to grow at a constant rate from one quarter to the corresponding quarter in the following year. It is the proper model for the purpose of calculating the cost of the common stock equity portion of total capital, in terms of investors' required return, for firms that pay dividends quarterly and normally increase dividends only once a year, if at all.

Q. Is the "Quarterly" DCF model the proper model for calculating the cost of the common stock equity portion of total capital in this rate case?

A. No. It is the proper way to calculate the total return required by *investors*, but that is not the appropriate rate of return to apply to rate base in proceedings such as these. For ratemaking purposes, the rate of return reflects the utility's cost of equity. As such, the rate of return should be developed from the perspective of the utility, not from the perspective of the investor.

Q. Please explain the difference.

A. The difference is the reinvestment of quarterly dividends paid by the utility. Because dividends are paid quarterly instead of annually, investors can choose how they wish to reinvest the dividends to obtain their total return for the year. They can, for example, reinvest in the equity of the utility. Alternatively, they can invest in the securities of another company. For this reason, then, the reinvestment of quarterly dividends (implicit in the quarterly DCF model) is the appropriate model when considering total return from the perspective of investors. The utility, however, does not control the reinvestment decisions of investors and therefore is responsible only for providing the fair rate of return as calculated in the "periodic" DCF model above. If the utility provides the fair rate of return, investors can reinvest the utility's dividends in a manner that will allow them to reach their total required return.

In other words, the cost of the common stock equity portion of total capital developed in the "Quarterly" DCF model accurately mirrors *investors'* current return requirements on common stock equity. It does not, however, reflect the *utility's* fair rate of return that must be applied to the rate base to yield the revenue requirement necessary to give investors what they require.

When the appropriate adjustments are made to reflect the perspective of the utility, the quarterly model reduces mathematically to the "Periodic" DCF model I presented above. In **Exhibit JDM-3,** I present the calculations that confirm this. Thus, the "Periodic" or "Annual" DCF model is the one to use in this proceeding.

Q. Are investors' expectations with regard to total return and expectations regarding dividend growth synonymous?

A. No. Both the "periodic" and the "quarterly" DCF models incorporate investors' expectations regarding the growth in dividends. Investors' expectations regarding total annual return relates to the "quarterly" DCF model that incorporates the effects of reinvesting quarterly dividends.

B. Selection of Comparable Company Group

Q. Do you use a comparable group of combination electric and gas utilities to determine the fair return on equity for DP&L?

A. Yes. I employ a group of ten electric and combination electric and gas utilities that are comparable in risk to DP&L.

Q. Please explain why comparable groups of companies are useful in this context?

A. My reasons for using data from multiple firms to determine the fair rate of return on equity, even if company-specific data are available, are: (1) a group of companies produces a more *reliable* and *objective* estimate of the current cost of capital required by capital markets; (2) the computation of comparable group's fair rates of return gives substance to the *Hope* decision's finding that a reference should be made to return on *investments with corresponding risks*; and (3) a specific jurisdiction's regulatory process affects investor expectations regarding the company whose fair rate of return is being set. This effect leads to the problem of "*circularity*." Circularity is particularly problematic in states where primary weight is given to the "sustainable dividend growth rate" in determining a company's fair rate of return on equity. This growth rate is a function of the proceeding that supposedly estimates this growth rate. The use of a proxy group will assuage the circularity problem.

Q. Why should circularity be a concern to the regulator?

A. Circular reasoning has long been considered a serious problem in the determination of a fair rate of return for investors. For example, the principle of "fair value" rate regulation (which dominated public utility regulation at both the state and federal level before the 1940s) gave way to "cost-based" rate regulation in large part because of a problem of circularity. As Professor Bonbright stated: "[a]ny attempt to test the fairness of the rates by reference to a valuation of the properties is an attempt to reason in a circle, or, if you like, to put the cart before the horse."[3] After all, a valuation of the properties will be based on the

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[3] J.C. Bonbright, *Principles of Public Utility Rates*. (New York: Columbia University Press, 1961), p. 164.

present value of the cash flows that the property will provide in the future, which, of course, will depend on the rates that can be charged to customers.

Whenever a commission uses a formula for determining a fair return that depends on investors' expectations of future growth, circularity arises because we know that investors' expectations depend on the return that the regulator is expected to allow. The path of supposed causation proceeds in both directions simultaneously, which, of course, is the source of circular reasoning. Another example of the circularity problem in the determination of the fair rate of return is the practice of using other public utilities' returns in a "comparable earnings" analysis. If the past earnings of the comparable group are low, it will likely result in a lower awarded rate of return on equity for the company under consideration. This company will, in turn, become part of another comparable group and will contribute to lower rates of return for other companies, creating a cycle from which it is difficult to escape.

By the same token, there is a circularity problem inherent in using a sustainable dividend growth formula for calculating the dividend growth in a DCF analysis when the principal components of that growth (i.e., the expected return and the retention ratio) are a function of the rates to be awarded. This practice is an impediment to the objective and impartial determination of a fair rate of return for a regulated utility.

Proxy group DCF calculations are far less likely to depend on the anticipated return granted in this case and, therefore, are far less likely to be susceptible to problems of circularity.

Q. What comparable companies do you employ in your DCF analysis of DP&L's electric operations?

A. The ten-company electric and combination electric and gas company group is listed in **Exhibit JDM-5** and **JDM-6**.

Q. What criteria do you use to determine that the companies you choose are comparable to DP&L's electric operations?

A. I have identified what I conclude are the minimum number of criteria that satisfy two basic objectives. The first basic objective is to assemble a group of companies with publicly-traded stock that are representative, on average, of the business risk faced by DP&L's electric delivery service operations. The second basic objective is to assemble a group of companies with stock price and dividend payment data that could be readily applied to the annual DCF model. I have consistently used this same approach to select comparable companies for a number of years.

Q. What criteria satisfy your first basic objective—that of mirroring the business risk faced by DP&L's investors?

A. DP&L operates a small-size electric utility—and the current rate case involves its electric operations. While DPL Inc. is the parent holding company of DP&L, the focus should be on determining the cost of common equity for DP&L's regulated utility operations in Ohio. The following two characteristics help to define the business risks faced by those who invest in either an electric or a combination electric utility company and are recognized by investment analysts as pertinent factors in evaluating the risk of an equity investment: (1) type of business, in this case a regulated electric utility; and (2) size.

Given these characteristics, I use two criteria to exclude companies from the proxy group for my combination electric and gas group. *First*, I select those electric and combination electric and gas utility companies that derive at least 80 percent of operating revenues from regulated electricity and gas operations. The average proportion of total operating revenue from electricity and gas activity in 2004 for the proxy group was 90.0 percent. DP&L derived 100 percent of its operating revenues from regulated electric activities and has total capital of $1.82 billion, as shown on **Exhibit JDM-7.** *Second*, I restrict the group of companies to those with a total capital of less than $10.0 billion. Some of the utilities in the proxy group have a higher total capital than DP&L and some have a lower total capital, but my goal (as stated above) is to create a proxy group that, *on average*, is representative of the business risk faced by DP&L. The average total capital for the group is about $3.75 billion.

Q. What criteria satisfy your second basic objective—to assemble a group of companies with stock price and dividend payment data that can be readily applied to the annual DCF model?

A. I establish three additional criteria to ensure that the data collected from the assembled proxy group companies can be used reliably in a DCF analysis. *First*, I restrict the group to utilities for which no explicit concern was raised in my financial data sources regarding the ability of the company to maintain its existing dividend. Because the DCF model I employ assumes a constant long-term dividend growth rate, it is inappropriate to apply the model to companies where a dividend decrease is expected.

Second, I exclude from the analysis any companies that are the publicly known targets of possible takeovers or are involved in mergers. Tender offers associated with takeovers generally affect stock prices in a temporary way unrelated to the overall cost of capital and make the use of those stock prices in a DCF analysis suspect. At this particular time, many electric and gas utilities are involved in merger activities and are therefore not potential candidates for my proxy group.

Third, I exclude from the group any companies that do not have consensus analyst's growth rate estimates, as summarized by Zachs Investment Research ("Zacks").

Q. What is the result of applying your criteria?

A. The result of applying the five criteria is that I develop a group of ten electric and combination electric and gas utilities, listed in **Exhibit JDM-5** and **JDM-6.** I conclude that this group has a degree of business risk that is comparable to DP&L's utility operations. **Exhibit JDM-5** explains the selection of the proxy groups. The resulting proxy group analysis produces an accurate estimate of the cost of equity for DP&L.

Q. Would it be preferable to use different selection criteria (such as bond ratings) or to use a larger proxy group?

A. No. Bond ratings measure the default risk associated with a firm's debt securities, such as its first mortgage bonds.[4] Bond ratings do not necessarily accurately measure the firm's equity risk.

[4] Indeed, a utility's various debt securities (*e.g.*, senior mortgage bonds, subordinated debt, etc.) are likely to have slightly different bond ratings. Further, different bond rating agencies (*e.g.*, Fitch, Moody's, and S&P) will sometimes have different bond ratings for a particular utility's first mortgage (or other) bonds.

While it might be possible to begin to select a proxy group by using a group of all utilities with a certain bond rating (say, all utilities with A rated bonds), it would still be necessary to use a screening process to eliminate: (1) very large firms; (2) firms that are highly diversified; (3) firms that are involved in mergers; and (4) firms that cannot be used in the standard DCF model (*e.g.*, firms that have recently cut their dividend). Thus, in the end, the sort of analysis that I have used in my testimony would be necessary even if you started with a group of firms that had the same A bond rating. Further, given that bond ratings measure default risk rather than equity risk, it is not at all clear that you would end up with a group that is more comparable (or even as comparable) to the risk of DP&L than the group that I have used in my testimony.

I fear that the end result after screening a group of utilities with the same bond rating would be a very small comparable group. It is generally desirable to have a fairly large comparable group, although it is also very important to have a comparable group that accurately reflect the subject utility's risks and that meet the requirements of the DCF model. It would certainly not be appropriate to simply add back companies—perhaps by re-jiggering the selection criteria—in order to obtain a large group. My ten-company electric and combination gas and electric utility group was selected using a methodology that I have consistently used for many years, which provides the best available basis for estimating the return on equity required by investors in DP&L's common equity.

C. Inputs into the DCF Calculations

Q. Please turn now to your description of the data you use to determine the fair rate of return for DP&L's electric service operations.

A. As I stated previously, it is important to use data that are: (1) consistent with the theoretical DCF method, (2) timely, and (3) unbiased. It is also important that the calculations made with the empirical data be reliable and stable.

The DCF analysis requires three data inputs: (1) current stock prices, P_0, (2) the current annual dividends, D_0, and (3) estimated dividend growth rates, g. I will deal with each of these DCF inputs in turn.

1. Calculation of the Stock Price, P_0

Q. What data do you use for the stock price input, P_0, in your DCF calculations?

A. I use stock prices obtained from the *Yahoo! Finance*. It is my normal practice to use stock prices on the latest day consistent with the filing, because only the latest stock prices are consistent with up-to-date investor expectations.[5] This is because the informative value (with regard to investor expectations) of yesterday's stock prices will be completely superseded by today's stock prices. This is a widely held tenet of efficient markets. If today's stock prices embody all of the expectations regarding the value of those stocks, then yesterday's prices represent "old news." Yesterday's prices, therefore, are useless as a gauge to investors' current expectations.

I use a closing stock price from on March 23, 2005, which was the latest day possible given DP&L's filing date in this case.

Q. Do you adjust the observed stock prices?

A. Yes. I perform an "ex-dividend date" adjustment on all of the stock prices to remove the known effect that the next quarterly dividend payment has on the stock price. Failing to remove this effect would make the stock price used inconsistent with the DCF formula.

This adjustment is necessary because of the assumption in all standard DCF models that the next quarterly dividend will be received one full period from the date the stock price is measured. The problem with this assumption is that the next quarterly dividend is usually closer than one full quarter from the day the stock price is observed. This affects the stock price in a known way and must be corrected in order to avoid a downward bias in the calculated result.

Q. What is the ex-dividend date and how can ignoring it bias the DCF calculations downward?

[5] I am very concerned about applying the cost of capital estimation methods that I use in a consistent manner. With regard to the stock price, for example, analysts could use selective stock price averaging to surreptitiously raise or lower a calculated result.

A. The ex-dividend date is the date on which the right to the next dividend no longer accompanies a stock. In other words, if you purchase a share of stock the day before the ex-dividend date, you will receive the next quarterly dividend paid by the Company. If you purchase that share one day later, you will not receive that dividend. Because dividends are an important part of the return to utility shareholders and in view of the relatively high payout ratios involved, the ex-dividend date is an important determinant of the stock price. Utility stock prices, like other stock prices, are observed to drop by an amount approximately equal to the quarterly dividend on the ex-dividend date.[6]

All of the DCF models that I outline in my testimony apply *only on the ex-dividend date*. In other words, all of these models assume that future dividends begin a full period hence. Failure to adjust the stock price observed at an arbitrary date to account for the ex-dividend date will bias the applicable stock price upward (by approximately the amount of the "accrued" portion of the quarterly dividend), and the resulting DCF calculation downward.

Q. How do you make the adjustment in the stock price?

A. I traditionally make the adjustment by removing from the stock price the portion of the dividend that has already accrued. I make this adjustment to the P_0 term before performing the DCF calculations for a proxy group. In cases where I employ a single day's stock price, the adjustment is straightforward. That is, I subtract from the stock price a proportion of the last dividend payment. That proportion is the number of days since the last ex-dividend date, divided by 90 (*i.e.*, a full quarter). I make this adjustment to the P_0 term in **Exhibit JDM-8** before performing the DCF calculations as shown in **Exhibit JDM-14.**

[6] A discussion of the importance of the ex-dividend date appears in most financial texts. See for example: E.F. Brigham, *Financial Management Theory and Practice,* 3rd Edition, (New York: The Dryden Press, 1982), 687. Empirical evidence on this phenomenon can be found in articles written by J.A. Campbell and W. Beranek, "Stock Price Behavior On Ex-Dividend Dates," *Journal of Finance*, 10, 4, (December 1955), 425-429; D. Durand and A.M. May, "The Ex-Dividend Behavior of American Telephone and Telegraph Stock," *Journal of Finance*, 15, 1 (March 1960), 19-31; and E.J. Elton and M.J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," *Review of Economics and Statistics*, (February 1970), 68-74.

2. Calculation of the Dividend, D_1

Q. How do you measure the dividend, D_1?

A. The DCF model requires that $D_1 = D_0 * (1+g)$, where D_0 is equal to the sum of the four most recent dividend payments. Thus, my starting point is to obtain the data for D_0. I obtain the sum of the past four quarterly dividends per share payments from *Value Line Investment Survey*.[7] I use the sum of the four most recent dividend per share payments for each company in the proxy group, which is the D_0 term shown on **Exhibit JDM-9.**

3. Calculation of Growth, g

Q. How do you estimate the dividend per share growth term, g?

A. I use three different prospective growth measures to estimate dividend growth from which I then take the simple average. The first is a measure of sustainable growth that examines projections of the separate components of dividend growth—that is, retained earnings and expected returns to book equity, as well as the possibility of issuing new shares at prices in excess of book values. The second measure is calculated using the forecasts of earnings per share published by *Value Line* in the issues listed above. The third measure uses analysts' estimates of earnings, as summarized by Zacks.

Q. Please describe the first method you use to calculate growth for the companies in your comparable group.

A. The first method is known as either the "retention growth" or "sustainable growth" method. This method produces a forward-looking, sustainable growth rate by multiplying the fraction of earnings that analysts expect a company to retain by the expected return on book equity. The sustainable growth method also allows for growth stemming from new issuances of stock at premiums over book value. This is a valid way of estimating future dividend growth, because future growth in the dividend can occur only if: (1) a portion of

[7] Data for the electric utilities were taken from *Value Line Investment Survey*, Edition 1 (March 4, 2005), Edition 5 (December 31, 2004) and Edition 11 (February 11, 2005). Each edition, updated regularly, provides data for a number of years for electric utilities from a particular region of the country.

the expected equity return is reinvested instead of being paid out in the form of dividends; or (2) if new common stock is issued at prices above current book values (causing existing shares to appreciate in value).

I estimate a sustainable growth rate for each company using the following formula:

$$g = B * R + S * V$$

Where:

B = expected retention ratio

R = expected return on equity

S = percent new equity expected

V = $1 - \dfrac{B}{M}$

This formula for estimating sustainable growth is explained in more detail in **Exhibit JDM-4**. This theoretical growth measure shows that investors can expect growth through both retained earnings and the sale of new stock at a premium of book. In this formula, current data, (on the end-of-year book values for 2003 and 2004) is used as a *factor* to transform the end-of-year 2007-2009 projected book values from *Value Line*[8] to a mid-year book value.

For all the publicly traded stocks in the comparable company group, investors can currently expect both forms of growth, as the market-to-book ratio for all is above one. As the Department has recognized in past decisions, if the $S*V$ term is ignored in the sustainable growth calculation, the resulting formula will not accurately represent investor perceptions of growth. The results of implementing the sustainable growth formula are presented in **Exhibits JDM-10** and **JDM-11.**

[8] For companies in *Value Line Investment Survey*, Edition 1 (March 4, 2005), the projected book value used is for 2008-10.

Q. Is the use of forecasts in your second and third methods, which use information provided by *Value Line* and Zacks, advisable?

A. Yes. The practice of using forecast growth rates provides a good basis for estimating the long-term growth of the utility. Financial analysts exert considerable influence over the many investors who do not possess the resources to make their own forecasts. The accuracy of these forecasts, in the sense of whether they turn out to be correct, is not the issue as long as they reflect widely held expectations. **Exhibit JDM-12** summarizes the *Value Line* and Zack's growth rates and provides the details of the calculation of the *Value Line* EPS growth rates.

Analysts' forecasts are sometimes criticized on the ground that it is very difficult to forecast growth rates accurately in the short term, let alone in the long term. However, this general objection is irrelevant to a DCF analysis because this method is based upon present investor expectations. Widely distributed forecasts influence both the current stock price and DCF cost of equity, not what the future will actually turn out to be.

Q. Are the five-year annual projected growth rates in earnings published by *Value Line* and Zacks reasonable indicators of long-term growth?

A. They are reasonable in the context of proceedings in which rate of return is being examined. It would be naïve to assume that the growth rates forecasted by *Value Line* and those summarized by Zacks are applicable far into the future. However, there are two strong reasons for employing such forecasts in the present proceeding. First, to the extent that investors employ forecasts like those published by *Value Line* and Zacks as long-term growth rates, these forecasts accurately reflect the current expectations of long-term growth included in the cost of capital. Second, *Value Line* and Zacks forecast growth rates might not be substantially different, on average, from what investors believe long-term growth prospects to be, given that the forecast is widely distributed in the financial community. In addition, a study by Brown and Rozeff shows that *Value Line* analysts make better forecasts than could be obtained by employing historical data only.[9]

4. Selling and Issuance Cost Adjustment

Q. Do you make any adjustments to your DCF results?

A. Yes. I make an adjustment for selling and issuance costs when calculating the DCF costs in **Exhibit JDM-14.**

Q. Why do you make such an adjustment?

A. The issuance of common equity, as well as long-term debt and preferred stock, involves costs. These costs are often measured as a percentage of the total debt, preferred equity or common equity issuance. Because of issuance costs, the net proceeds of a debt, preferred equity or common equity issuance will always be less than the total purchase price of the securities issued. Unless an adjustment is made to reflect this phenomenon in the fair rate of return—an adjustment consistent with the issuance cost adjustment already made for debt and preferred stock—the resulting fair rate of return calculations will be too low. The same problem with a return that is too low will result if selling and issuance costs are ignored in calculating embedded debt costs.

Q. Is such an adjustment generally made by regulators?

A. Yes. An adjustment to factor out selling costs is made as a traditional part of computing the embedded cost of debt and preferred stock—even though it is often contested where equity is concerned.

Q. Please explain.

A. Basing required returns on net, rather than gross, proceeds is standard regulatory practice when the capital is in the form of debt or preferred stock. It is inconsistent—and the source of improper DCF calculations—to exclude the same type of issuance cost allowance from

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[9] L.D. Brown and M.S. Rozeff, "The Superiority of Analyst Forecasts As Measures of Expectations: Evidence From Earnings," *Journal of Finance*, 33, 1 (March 1978), 1-16.

outstanding common stock balances if those costs were incurred in the issuance of that common stock and were not reflected as a current expense in rates at the time the issuance was made. For long-term debt and preferred stock issuances, these costs are capitalized by calculating a required rate of return on the net proceeds to DP&L. It would be inconsistent to allow the capitalization and collection of these costs on long-term debt and preferred stock issuances and not to allow the collection of the same kind of costs on common stock issuances.

Q. What is the most common way for regulatory commissions to compensate for issuance costs?

A. The most common way to compensate utilities for necessary issuance costs related to common stock, as well as for preferred stock and long-term debt, is to allow a return *on* these costs for any one year and a return *of* these costs over the life of the issue. For common stock, because the life of the issue is, in essence, perpetual, the return component to recover the return on these costs is permanently a part of the return on equity. The only way these costs will "go away" is if they are paid off as a current expense. Failing to compensate a utility for its issuance costs will assure the under-recovery of its prudently incurred costs of raising capital.

Q. Is there more than one way that a commission can deal with selling and issuance costs?

A. Yes. A commission appropriately can handle these costs in one of three ways. *First*, a commission can allow the company to recover these costs automatically in the year they are incurred as an expense component of the revenue requirement (or the expense could be amortized over a number of years—with a return on the outstanding balance).

Second, a commission can allow the issuance costs to be included in the rate base (like the treatment of interest charges on construction work in progress). This will allow the company to earn a return *on* the costs, as opposed to a return *of* the costs.

Third, a commission can adjust the cost of capital upward over the life of the issue. This adjustment in effect allows the company to earn a return *on* the issuance costs, even though the costs are not in the rate base. The financial result and the revenue requirement are the same as for the second method.

All of these methods would compensate the utility for the actual issuance costs incurred.

Q. How do you make your issuance and selling expense adjustment?

A. It is proper to include an issuance expense return adjustment for the entire equity component of the capital structure.[10] Therefore, I use the conventional form of the issuance expense adjustment:[11]

$$r = \frac{D_1}{P_0 * (1 - f)} + g$$

Where: (3)

r = required return adjusted for issuance expenses

f = flotation cost percentage

For the purpose of choosing an appropriate value for f, the flotation cost percentage, I refer to a publication by Victor Borun and Susan Malley as well as information specific to DP&L's most recent public equity issuances.[12] Borun and Malley conclude that total flotation costs for electric utilities are about 5.5 percent. As shown in **Exhibit JDM-13**, the average of DP&L's last ten equity offerings is 4.27 percent. The average of the two is 4.88 percent, which I use as the issuance cost percentage for the DCF calculations in this case, according to the formula above.

[10] Support for using total common equity appears in: Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

[11] This formula appears in Roger A. Morin, *Utilities' Cost of Capital*, (Arlington Virginia: Public Utilities Reports, Inc., 1984), 106; and Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36.

[12] Victor M. Borun and Susan L. Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, (February 20, 1986), 33-39.

Q. Please explain why the issuance expense adjustment should be made to total common equity.

A. Investors are entitled to earn the expected cost of capital on their investment. The DCF model illustrates that this expected cost is equal to dividend payments plus capital gains on the value of their shares. The cash paid in by investors is greater than the net proceeds that the company takes in. Therefore, the company must earn a greater return on the smaller net proceeds balance to compensate investors adequately for their expected cost of capital. But the money paid to the investors in any year, the dividend, reflects only a portion of the returns on equity. Retained earnings represent the other portion, or the funds used to finance future growth and future dividends. If retained earnings do not receive a selling and issuance return adjustment, they will not grow at a rate sufficient to allow for the payments of dividends at investors' expected growth rate in the future and the company would not earn its true cost of capital.

D. Empirical DCF Calculations for Proxy Group

Q. How do you calculate a DCF cost of common equity for the proxy group of combination electric and gas utilities and the proxy group of electric utilities?

A. Using the ex-dividend date adjusted stock prices for March 23, 2005, the most recent four actual dividend per share payments, the average of the sustainable growth and forecast earnings growth estimates, and the issuance cost method shown above, I estimate a cost of common equity for the electric and combination electric and gas proxy group of **10.39 percent,** as shown in **Exhibit JDM-14.**

IV. REASONABLENESS CHECKS

Q. What checks of reasonableness do you perform?

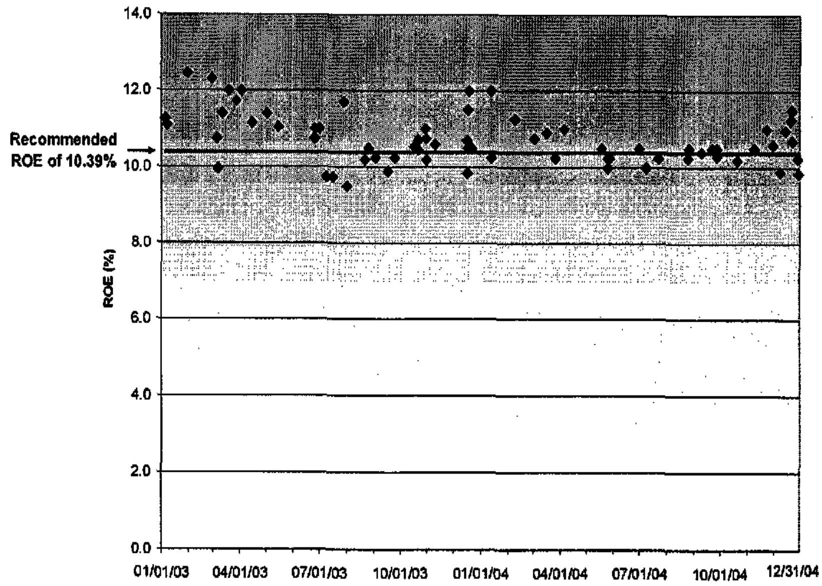
A. I review the most recent rate of return decisions for electric and gas utilities listed by Regulatory Research Associates from January 2003 through December 2004 and I calculate the cost of common equity using CAPM.

A. Allowed Return on Equity Comparison

Q. Please explain how you develop the allowed return on common equity comparison.

A. **Figure 1** shows the range of electric and gas utilities' returns on equity that have been authorized by regulatory commissions throughout the country between January 2003 and December 2004. My database covers 86 decisions. The figure also shows the number of decisions associated with each allowed return on common equity figure. I have indicated where my recommended return on equity of **10.39 percent** falls within the range of ROEs. **Exhibit JDM-15** presents the individual state commissions' allowed returns that make up the figure.

Figure 1 Electric and Gas Utility Rate Decisions (January 2003-December 2004)



Q. What conclusions do you draw from the information presented in Figure 1?

A. My recommended return is below the mean and the median (10.83 percent and 10.65 percent respectively) of the range of returns authorized by commissions throughout the country over the period January 2003 through December 2004, which suggests that my recommendation is reasonable.

B. CAPM Method

Q. Please provide your overall evaluation of the CAPM.

A. Unlike the DCF model, the CAPM is difficult to apply in utility rate cases. The DCF renders a cost of capital estimate for each company in a proxy group. Some might seem a bit high and others a bit low, but the individual company results have objective "measures of central tendency," such as averages.

This is not true for the CAPM. The CAPM is the sum of two components: (1) a risk-free rate applicable to all companies; and (2) a company-specific risk premium (the product of a company-specific beta and a market risk premium). There are a wide variety of risk-free rates from which to choose (*e.g.*, long-term/short-term/average of both). Furthermore, because the same risk-free rate applies as an additive term to all companies' cost of equity estimates, there is no measure of central tendency in the result. In short, we cannot resolve the question of uncertainty surrounding short-term versus long-term rates by repeated sampling.

In the end, the CAPM analyst has to choose a risk-free rate that drives the results—precisely the type of choice that limits the model's objectivity and effectiveness. Indeed, this subjectivity is the principal reason I avoid the CAPM as an ROE method, and have avoided relying on it if it is possible to use a DCF approach instead.

Nevertheless, *risk premiums methods* are sometimes used to determine the cost of common equity in Ohio and, therefore, I need to make it clear what the concerns are about the use of CAPM to set the cost of common equity for DP&L.

Q. Is there more than one way to calculate the CAPM model?

A. Yes. The CAPM formula itself is rather straightforward. Its components are: (1) the risk free rate of return; (2) the market rate of return; and (3) the beta. Yet despite this algebraic simplicity, experts have applied different methods to obtain each of these components and to compute the required rate of return. The effects of choosing one method over another can be to substantially change the required cost of capital.

Q. Have you calculated a CAPM ROE?

A. Yes, I have. While I believe that the DCF alone should be used in this case (a recommendation that I have consistently made for many years), I have derived CAPM return on equity estimates. My CAPM results for my comparable group are shown on **Exhibit JDM-16.**

I use a risk-free rate of 4.76 percent, which is the yield on 30-year treasury bonds, as reported in the *Value Line Selection and Opinion* (March 18, 2005, page 1819). I use the most up-to-date *Value Line* betas for the companies in my comparable group.

Two approaches are used to calculate the appropriate risk premium: (1) I calculate a "top-down" return on the market (the S&P 500) using analysts' estimates; and (2) I use historical Ibbottson and Sinquefield data.

Forward-looking measures of the market risk premium are available. A forward-looking market risk premium can be calculated by subtracting the risk-free rate from the estimated 12.53 percent "top-down" cost of equity capital of the S&P 500. Yahoo! Finance[13] provides a 10.49 percent estimate of the "top-down" estimated five-year earnings growth rate of the S&P 500, and S&P[14] provides a 1.76 percent estimate of the current dividend yield of the S&P 500. Combining these inputs using the standard DCF model provides a forward-looking, top-down DCF cost of common equity for the S&P 500 of 12.53 percent, as shown on **Exhibit JDM-17.** This method of estimating the risk premium produces a 10.67 percent result for the proxy group using CAPM.

While Ibbottson and Sinquefield's market risk premium data is a useful source of information on the historical risk premium of large company stocks relative to long-term government bonds, it is backward looking. Moreover, the recent 2000-2003 period has had a severe impact on the equity risk premium, when calculated using historical data. If

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[13] "Yahoo Finance: S&P Growth Estimate, Next 5 Years," available at http://biz.yahoo.com/z/a/v/vz.html (downloaded March 23, 2005).

[14] "S&P 500 Statistics," available at http://www2.standardandpoors.com/NASApp/cs/ContentServer?pagename=sp/Page/IndicesIndexPg&l=EN&b=4&f=1&s=6&ig=48&i=56&r=1&xcd=500&fd=IndicesMonthEnd_500 (downloaded March 23, 2005).

Ibbottson data for 2000-2003 is used, the counter-intuitive result is a lower equity risk premium. If Ibbottson data for 1926 to 2003 is used, the CAPM result is 9.80 percent.

If Ibbottson data for 1926 to 1999 is used, the CAPM result is 10.67 percent. I would generally be more skeptical about the backward-looking results produced by using Ibbottson historical data when developing an equity risk premium.

In any event, I use CAPM only as a check on my DCF results.

V. THE GENERAL SOURCES OF ELECTRIC UTILITY COMPANY RISK

Q. What is the purpose of this section of your testimony?

A. In this section, I examine the basis of the business risks for electricity utilities, both to show that they are substantial and to point out that they differ very little—in principle or in practice, from one another.

Q. What are the basic types of business risks applicable to electricity utilities?

A. Electricity utilities face practical risks in ratemaking, risks in planning and upgrading their systems to maintain reliability and dealing with problems of accidents and outages that interrupt service.

- Tariff structure risks. Electricity utilities have largely fixed costs devoted to their respective networks—but collect their revenues largely through volumetric rates. This exposes revenues—and earnings—to risks of unseasonable weather and economic downturns. This is a basic risk for utilities that follows from a rate structure that does not (for various reasons) match the structure of costs.

- Electricity utilities connect to the multitude of a state's end-use consumers. Therefore, electric utilities are the ones charged with the planning of upgrades to networks that in many cases are decades old. The needs for major expenditures to provide safe local service do not always follow rate case schedules—and hence are often not recouped, as such.

- Risks of service interruptions. Major or minor service interruptions are generally the responsibility of the electric utility—as are the costs of remedying outages. Storm damage to electricity wires and sub-stations is the responsibility of the utility, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- Adequacy of depreciation. The depreciation allowance included in utility company rates is an estimate based in historic experience. Depreciation allowances do not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under depreciated, and changes in technology or regulation will cause shareholders to bear the result of inadequate depreciation.

- Risk of technological bypass. Electricity utilities are at risk for customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- Risk of the competitiveness of rates. Electric utilities are at risk for the continued variables of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable. In this instance, the controlling limit on rates would be competition from other sources, not regulatory limits or charges—and utilities would be unable to recover their actual costs.

- Risk of timeliness and adequacy of allowed revenue levels. Electric utilities face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. The utilities will absorb such costs until they become large enough to cover the cost of a rate filing.

VI. THE CAPITAL STRUCTURE, EMBEDDED COST OF LONG-TERM DEBT, AND OVERALL COST OF CAPITAL

Q. What is the required overall rate of return for a firm?

A. The required rate of return for a firm is the firm's weighted average overall cost of capital ("WACC"). The WACC is the sum of the costs of the component parts of the capital structure, *i.e.*, debt, preferred stock, and common equity, weighted by their relative proportions in the capital structure.

On **Exhibit JDM-7**, I present the capital structure and the cost of capital components that are appropriate for DP&L. I use the projected actual capital structure ratios that would be applicable for DP&L at the time that new rates would go into effect. **Exhibits JDM-18** and **JDM-19** present the embedded cost of long-term debt and preferred stock, respectively. The overall cost of capital is **8.78 percent.**

Q. What is the appropriate capital structure to employ in determining DP&L's overall cost of capital?

A. There are two considerations that are noteworthy in determining the appropriate capital structure. First, since this rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components upon the best available estimates for the period of time in which the rates will be in effect. The appropriate capital structure should reflect all known changes, including new security issuances and retirements.

Second, modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[15]

Third, a utility's management must be granted a measure of discretion as to the type of capital raised. Having a solid level of financial integrity can provide rate stability and other benefits to customers. DP&L's current bond rating for its first mortgage debt, which is at the low end of an investment grade rating, indicates a need solidly to maintain or increase its financial integrity.[16]

Q. Do you recommend that the Commission use the projected actual capital structure for the Company as of the date that new rates are expected to go into effect?

A. Yes, I do. The capital structure, as shown on **Exhibit JDM-7**, reflects the capitalization that is expected at the time when new rates would go into effect.

Q. What issues do you address pertaining to the cost of debt for DP&L?

A. Regulated utilities generally use a mixture of debt and equity (and sometimes preferred stock) to raise capital for their operations. The mixture of debt and equity represents generally a desire on the part of a company's management to minimize the overall cost of capital. The cost of debt, as such, is not generally a contentious aspect of regulated rate

[15] See Roger Morin, *Utilities' Cost of Capital* (Arlington, VA: PUR, 1984), p. 268.

[16] The first mortgage debt for DP&L is rated BBB- by *S&P*.

cases, as it is customary to use a company's embedded—and hence observable—interest costs on its outstanding long-term debt. I would also note that *Value Line* projects generally that electric utilities will increase their equity ratios over the next few years.

VII. CONCLUSION

Q. What is your final recommendation for DP&L's rate of return on equity?

A. My final recommended rate of return for DP&L is **10.39 percent**, which is based on the DCF results for a proxy group of electric and combination electric and gas utilities, as shown on **Exhibit JDM-7**.

Q. Please summarize your conclusions as to the overall weighted average cost of capital for the Company.

A. I conclude that the overall cost of capital for the Company is **8.78 percent**, as shown on **Exhibit JDM-7**.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. 05-276-EL-AIR
Exhibit JDM-1

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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporation, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY SINCE 1994

Before the Circuit Court of Fairfax, Virginia, Testimony of Jeff D. Makholm on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. February 16th & 17th 2005. Subject: Valuation of capacity expansion project.

Before the Public Utilities Commission of the State of Oregon, Direct Testimony and Exhibits on behalf of Portland General Electric. Docket No.UE-88 Remand. February 15, 2005. Subject: The cost consequences of abandoning the regulatory compact in Oregon on prudent invested capital.

Before the Public Utilities Commission of Nevada, Testimony and Exhibits on behalf of Sierra Pacific Power Company. Docket No 05-_____. January 5, 2005. Subject: Prudence of gas purchase costs.

Before the Public Utility commission of Oregon, Direct Testimony on behalf of Portland General Electric. Docket No. UE-165. November 17, 2004. Subject: Power supply risk related to PGE's hydroelectric generation sources.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Nevada Power Company. Docket No. 04-11____. November 10, 2004. Subject: Examination of the prudence of gas purchase and hedging decision in the Company's 2004 deferral case.

Before the Illinois Commerce Commission, Testimony on behalf of Nicor Gas Company. Docket No. 04-0779. November 1, 2004. Subject: Cost of Capital.

Rebuttal Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 15, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the Circuit Court of Fairfax, Virginia, Deposition of Jeff D. Makholm on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. October 1, 2004. Subject: Valuation of capacity expansion project.

Expert Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 1, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Rebuttal Report before the London Courts of International Arbitration on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. September 17, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Expert Report before the London Courts of International Arbitration on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. August 6, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-12002. March 29, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 03-10001 and 03-10002. February 5, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

Before the New Zealand Commerce Commission, Testimony on behalf of Orion New Zealand. November 5, 2003. Subject: Productivity measures used in resetting the price path thresholds for electricity distributors in New Zealand.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of FairPoint New England Telephone Companies. July 11, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. May 14, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-1014. May 5, 2003. Subject: Prudence of gas procurement and hedging program.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of FairPoint New England Telephone Companies. April 7, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 02-11021. March 31, 2003. Subject: Prudence of gas procurement and hedging program.

Before Federal Communications Commission, Testimony on behalf of Iowa Telecommunications Services, Inc. Case No. March 25, 2003. Subject: Cost of capital.

Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ER03-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

Before the New York State Public Service Commission, Affidavit of Jeff D. Makholm in support of Rochester Gas and Electric Corporation's Response to Staff's November 8, 2002 filing. Case No. 02-E-0198, 02-G-0199. November 14, 2002. Subject: Respond to staff's filing with respect to the rate-of-return and risk impacts of various regulatory mechanisms.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of American Electric Power Company, Inc., Mutual energy CPL, LP, Mutual Energy WTU, LP and Centrica PLC, Centrica N.S. Holding, Inc., Centrica Holdco, Inc.. Case No. 25957. October 28, 2002. Subject: Impact of the merger on competition in the retail electric market.

Expert testimony on behalf of Azurix Corp. before the ICSID (International Center for the Settlement of Investment Disputes), in the case of Azurix Corp v. Government of Argentina, October 15, 2002. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the State of New York Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. September 30, 2002. Subject: Cost of capital

Before the Connecticut Department of Public Utility Control, Update and Rebuttal Testimony (Response to Interrogatory EL-174) on behalf of The United Illuminating Company, Case No. 01-10-10, April 4, 2002. Subject: Cost of capital.

Before the State of New York Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. February 15, 2002. Subject: Cost of capital.

Before the Alberta Energy and Utilities Board, Update of Evidence on behalf of UtiliCorp Networks Canada, November 30, 2001. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the Connecticut Department of Public Utility Control, Direct Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, November 15, 2001. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, October 24, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony of Jeff D. Makholm and Charles J. Zarkadas on behalf of Community Service Telephone Company. September 6, 2001. Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of the Association of Oil Pipe Lines. Case No: OR96-2-000. June 21. 2001. Subject: Light-handed regulation of oil pipeline tariffs.

Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Federal Energy Regulatory Commission, Affidavit of Jeff D. Makholm, Ph.D. on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

Before the Public Utility Commission of the State of Oregon, Rebuttal Testimony on behalf of Portland General Electric Company. May 21, 2001. Subject: Cost of capital.

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Before the State of New Jersey, Division of the Ratepayer Advocate, Cross-Answering Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564 , March 26, 2001. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

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Before the Federal Energy Regulatory Commission, "Assessment of PJM Owner's Transmission Enhancement Package," prepared in support of the PJM (Pennsylvania, New Jersey, Maryland) electricity transmission owners as part of their Order No. 2000 compliance filing. Docket No. RT01-2, October 11, 2000. Subject: Analysis of incentive package for transmission efficiency.

RECENT TESTIMONY (SINCE 1994) (CONT.)

Before the Appeal Panel under Section 38(2) of the Office of the Regulator-General Act 1994, Victoria, Australia. In the matter of an appeal pursuant to s.37 of the Act brought by United Energy Ltd., Testimony on behalf of the Office of the Regulator General, October 10, 2000. Subject: The distinctions between price cap and traditional cost-based regulatory practices.

Before the Alberta Energy and Utilities Board, Evidence on behalf of UtiliCorp Networks Canada, September 1, 2000. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the State of Maine Public Utilities Commission, Surrebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, August 10, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the State of New Jersey, Division of the Ratepayer Advocate, Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564 , July 26, 2000. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, June 22, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 12, 2000. Subject: Investigation Concerning the Unbundling of delivery Services Under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 5, 2000. Subject: Investigation Concerning the Unbundling of delivery Services Under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase II, October 21, 1999. Subject: Billing credits for unbundled services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0115, October 15, 1999. Subject: Recouping nuclear decommissioning expenses for electric power plants.

Before the State of Maine Public Utilities Commission, Report on behalf of Central Maine Power Company, Case No. 97-580 (Phase II), October 12, 1999. Subject: Cost of service for unbundled electricity transmission and distribution.

Before the Illinois Commerce Commission, Direct Testimony on behalf of the Commonwealth Edison Company, Case No. 99-0013, Phase II, October 8, 1999. Subject: Billing credits for unbundled services.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of Central Maine Power Company, Case No. 99-666, September 30, 1999. Subject: Empirical analysis and productivity offset for price cap formula.

Before the High Court of New Zealand, The Commerce Commission versus Caltex New Zealand Limited, Mobil Oil New Zealand and Shell New Zealand Limited. Reply Brief of Evidence, August 23, 1999. Subject: Price fixing in petroleum marketing.

RECENT TESTIMONY (SINCE 1994) (CONT.)

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Before the Illinois Commerce Commission, Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Case No. 99-0117, May 17, 1999. Subject: Whether marginal cost pricing principles can provide the basis for an efficient tariff design for the company's delivery service tariffs.

Before the Illinois Commerce Commission, Rebuttal Testimony on Behalf of Commonwealth Edison Company, Case No. 99-0117, May 10, 1999. Subject: Whether marginal cost pricing principles can provide the basis for an efficient tariff design for the company's delivery service tariffs.

Before the State of Illinois, Illinois Commerce Commission. Direct Testimony on behalf of Commonwealth Edison Company, Case No. 99-0017, March 12, 1999. Subject: Whether marginal cost pricing principles can provide the basis for an efficient tariff design for the company's delivery service tariffs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of CITGO Petroleum Corporation, Case No. OR-99-1, March 19, 1999. Subject: To review and comment on Explorer Pipeline's application to the Federal Energy Regulatory Commission for market-based oil pipeline rates.

Before the State of Illinois, Illinois Commerce Commission. Reply Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, February 17, 1999. Subject: Unbundling services provided by electric distribution companies.

Before the State of Illinois, Illinois Commerce Commission. Direct Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, February 4, 1999. Subject: Unbundling services provided by electric distribution companies.

Before the State of Illinois, Illinois Commerce Commission. Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 98-0680, February 10, 1999. Subject: Tariff structure for electric distribution companies.

Before the Federal Energy Regulatory Commission, Testimony on behalf of CITGO Petroleum Corporation, Case No. OR-99-1, January 29, 1999. Subject: To review and comment on Explorer Pipeline's application to the Federal Energy Regulatory Commission for market-based rates.

Before the State of Illinois, Illinois Commerce Commission. Rebuttal Testimony on behalf of Illinois Gas Transmission Company, Case No. 98-0510, January 11, 1999. Subject: Joint Application of Illinois Gas Transmission Company and Nuevo Energy Company for Certification of Illinois Gas Transmission Company as a Common Carrier Pipeline.

RECENT TESTIMONY (SINCE 1994) (CONT.)

In the matter of an arbitration to determine the price for treatment of Kapuni gas, before Sir Ian Barker QC between Shell Company and Todd Petroleum v. Natural Gas Corporation of New Zealand, November 17, 1998, Statement of Evidence of Jeff D. Makholm.

Before the United States District Court for the Western District of Missouri (Riverside Pipeline Company, *et al*, v. Panhandle Eastern Pipe Line Company, Case No. 97-0642-CV-W-4), Supplemental Expert Report of Jeff D. Makholm on behalf of Riverside Pipeline Company, *et al*, October 28, 1998.

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Before the Australian Competition and Consumer Commission (ACCC) and the Victorian Office or the Regulator General (ORG), prepared comments at a public hearing held in Melbourne regarding the cost of capital for Victoria's gas transmission and distribution franchises, on behalf of BHP Petroleum Pty Ltd, July 3, 1998.

Before the Federal Energy Regulatory Commission, Prepared Comments submitted on behalf of the Edison Electric Institute on the Commission's "ISOs and Transmission Pricing" Panel, Docket No. PL98-5-000. (April 16, 1998).

Before the High Court of New Zealand, Auckland Registry, Affidavit on Behalf of Viaduct Harbour Holdings, Ltd., Docket No. CP 786/97, August 8, 1997. Subject: Economic analysis of acquisition of land by a public authority

Before the Pennsylvania Public Utility Commission, Prepared Direct Testimony on behalf of Duquesne Light Company, Docket No. R-00974104, July 12, 1997. Subject: Cost of capital and treatment of stranded electric utility costs as part of Pennsylvania's overall electricity restructuring plan.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of Consolidated Edison Company of New York Inc., et al, Docket No RP95-197-000, March 25, 1997. Subject: The pricing of expanded transmission capacity.

Before the State Corporation Commission of the State of Kansas, Prepared Direct Testimony on behalf of Kansas Pipeline Partnership, Docket No. 97-WSRG-312-PGA, May 23, 1997, in the matter of the Partial Suspension of Western Resources' Monthly Purchased Gas Adjustment (PGA) Effective Date December 1, 1996. Subject: Prudence examination of several gas commodity and gas transportation contracts.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of Consolidated Edison Company of New York, Inc., Owens Corning, PECO Energy Company, et al, Docket No. RP95-197-71-001, March 24, 1997. Subject: The pricing of expanded transmission capacity.

Before the Massachusetts Department of Public Utilities, Prepared Direct Testimony on behalf of Distrigas of Massachusetts Corporation, Docket No. D.P.U. 96-50, July 19, 1996. Subject: Retail unbundling of local distribution rates and recovery of stranded costs.

Before the Federal Energy Regulatory Commission, Prepared Cross-Answering Testimony on behalf of Consolidated Edison Company of New York, Inc., Owens-Corning Fiberglas Corporation, PECO

RECENT TESTIMONY (SINCE 1994) (CONT.)

Energy Company, et al., Docket No. RP95-197-000, May 28, 1996. Subject: The pricing of expanded transmission capacity.

Before the New Zealand Select Parliamentary Committee on Transportation, Comments on the Proposed Amendments to the Regulation of Airports in New Zealand (with Alfred E. Kahn), March 13, 1996. Subject: The oversight of airport authorities and conduct of airport pricing practices.

Before the Virginia State Corporation Commission, Prepared Rebuttal Testimony on behalf of Southwestern Virginia Gas Company, Case No. PUE950019, October 13, 1995. Subject: Fair rate of return.

Before The State Corporation Commission of the State of Kansas, Prepared Rebuttal Testimony on behalf of Kansas Pipeline Partnership, Docket No. 192,506-U, Docket No. 192,391-U, Docket No. 192,507-U, August 1, 1995. Subject: Competitive entry and pricing of new gas pipeline capacity.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Prepared Rebuttal Testimony on behalf of Valley Resources, Inc., Case No. 2276, June 15, 1995. Subject: Cost of capital

Before a private arbitration panel, in the Matter of Marathon Oil Company v. Southern California Gas Company, Expert Rebuttal Report, April 21, 1995. Subject: Capacity costs on major U.S. pipeline companies.

Before a private arbitration panel, in the Matter of Marathon Oil Company v. Southern California Gas Company, Expert Initial Report, April 7, 1995. Subject: The effect of U.S. interstate gas pipeline capacity on gas contract prices and delivery conditions.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission, Prepared Direct Testimony on behalf of Valley Resources, Inc., Case No. 2276, January 19, 1995. Subject: Cost of capital.

Before the Virginia State Corporation Commission, Prepared Direct Testimony on behalf of Virginia Electric and Power Company, Case No. PUE940052, January 17, 1995. Subject: Utility line extension and pricing policies.

Before the Virginia State Corporation Commission, Prepared Direct Testimony on behalf of Virginia Electric and Power Company, Case No. PUE940031, September 30, 1994. Subject: Utility line extension and pricing policies.

Before the Federal Energy Regulatory Commission, Comments of NERA, sponsored by Commonwealth Gas Company and Yankee Gas Services, Docket No. PL94-4-000, (with Louis Guth) September 26, 1994. Subject: Pricing interstate pipeline capacity expansions.

Before the Kansas Corporation Commission, Prepared Rebuttal Testimony Regarding the Fair Rate of Return on behalf of Kansas Pipeline Partnership and Kansas Natural Partnership, Docket No. 190,362-U, September 23, 1994. Subject: Cost of capital.

Before the Kansas Corporation Commission, Prepared Rebuttal Testimony on Market Entry Cost Recovery on behalf of Kansas Pipeline Partnership and Kansas Natural Partnership, Docket No. 190,362-U, September 23, 1994. Subject: Gas pipeline market power in firm delivery capacity and evaluation of the economic benefits of pipeline entry.

Before the California Public Utilities Commission, Amended Direct Testimony on behalf of Sierra Pacific Power Company, Application 94-05-009, July 1, 1994. Subject: Cost of capital.

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Before the Federal Energy Regulatory Commission, Prepared Rebuttal Testimony on behalf of the New England Customer Group of 15 Natural Gas Distribution Companies, Docket No. RP91-203-000 (Tennessee Gas Pipeline Company), May 27, 1994. Subject: Gas pipeline rate design.

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Before the Public Service Commission of the State of New York, Prepared Direct Testimony on behalf of the Brooklyn Union Gas Company, Case No. 93-G-0941, November 1, 1993. Subject: Fair rate of return.

Before the Public Service Commission of the State of Wisconsin, Rebuttal Testimony on behalf of Wisconsin Gas Company, Docket No. 6650-GR-111, August 20, 1993. Subject: Fair rate of return.

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Before the Public Service Commission of the State of New York, Prepared Supplemental Testimony on behalf of The Brooklyn Union Gas Company, Case No. 90-G-0981, July 29, 1991. Subjects: Reasonableness of a multi-year rate of return settlement.

Before the New Jersey Board of Public Utilities, Prepared Direct Testimony on behalf of South Jersey Gas Company, BRC Docket No. GR9107124 3J, July 17, 1991. Subjects: Cost of capital and the benefits of weather normalization for gas distribution companies.

Before the State of New Jersey Board of Public Utilities, Prepared Rebuttal Testimony, BPU Docket No. GR 9012, on behalf of Elizabethtown Gas Company, June 10, 1991. Subject: Fair rate of return and weather normalization clauses

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Before the Oregon Public Utility Commission, Prepared Rebuttal Testimony on behalf of Portland General Electric Company, Case No. UE-79, November 19, 1990. Subject: Cost of capital.

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Before the Pennsylvania Public Service Commission, Prepared Rebuttal Testimony on behalf of Philadelphia Electric Company, Docket No. R-811719, February 16, 1982. Subject: Cost of capital.

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"Supplementary Submission to IPART on AGLGN's Proposed Costs and Tariffs" on behalf of BHP (April 15th, 1999). This submission explains how NERA recalculated charges for AGLGN in New South Wales, Australia.

"Initial Comments on AGLGN's Revised Access Arrangement Information" on behalf of BHP (March 20th, 1999). This submission presents NERA's comment to AGLGN submission to IPART in New South Wales, Australia.

"International Restructuring Experience" (February 12th, 1999). This paper surveys a number of countries whose experience of restructuring and competition in the electricity sector is directly relevant to the proposed changes in Mexico – Argentina, Australia, Chile, Guatemala, New Zealand, Norway, Spain, the US and the UK

"Report I: Review of the Regulatory Framework" (January 18th, 1999). This report presents the options for a natural gas framework in Peru.

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"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

RECENT INTERNATIONAL REPORTS (CONT.)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

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"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

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"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

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