Staff Report

of

Exceptions and Recommendations

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of the Dayton Power and Light Company for Approval of Their Transition Plan Pursuant To Section 4928.31, Revised Code and for the Opportunity to Receive Transition Revenues As Authorized Under Sections 4928.31 to 4928.40, Revised Code.	)	Case No. 99-1687-EL-ETP
In the Matter of the Application of Dayton Power and Light Company for Approval to Change Accounting Methods.	)	Case No. 99-1688-EL-AAM
In the Matter of the Application of Dayton Power and Light Company for Approval to Amend its Tariff.	)	Case No. 99-1689-EL-ATA

PUCO

The Public Utilities Commission of Ohio

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Alan R. Schriber, Chairman
Ronda Hartman Fergus, Commissioner
Craig A. Glazer, Commissioner
Judith A. Jones, Commissioner
Donald M. Mason, Commissioner

To The Honorable Commission:

In accordance with the Section 4928.32(B), Revised Code, the Commission's Staff has conducted its investigation in the above matter and hereby submits its report of recommendations.

This Report has been prepared under the overall supervision of Christine Pirik, Chief of Staff, Deborah Gnann, Director of the Consumers Service Department, Douglas R. Maag, Deputy Director of the Utilities Department, J. Edward Hess, Chief of the Electricity Division of the Utilities Department and Stephen E. Puican, Chief of the Gas and Water Division of the Utilities Department.

The Unbundling portion of the report was prepared under the supervision of Robert Fortney, the Corporate Separation portion was prepared under the supervision of Joseph Buckley, the Operational Support System Planning portion was prepared under the supervision of Carl Evans, the Employee Assistance portion was prepared under the supervision of Raquel Dowdy-Cornute, the Educational portion was prepared under the supervision of Lee Veroski, the Transition Charges portion was prepared under the supervision of Christopher Kotting, the Transmission portion was prepared under the supervision of Patrick Sarver, and the Shopping Incentives portion was prepared under the supervision of Daniel Johnson.

Copies of the Staff Report have been filed with the Docketing Division of the Commission and served by certified mail upon the utility or its authorized representative and all parties of record. Interested parties are advised that the Commission has set this matter for hearing on June 5, 2000.

This report is intended to present the Staff's exceptions to the Applicant's transition plan filing for the Commission's consideration and to recommend solutions for those exceptions. Not every proposed provision, item, or process will be discussed. Only provisions, items or processes with which the Staff takes exception are presented in this report. Exceptions presented include those that appear to be:

- In conflict with public policy including, but not limited to, public health, welfare, and safety,

- In conflict with current and proposed Commission Rules.

- In conflict with acceptable utility regulatory or disciplinary practices

This Report does not purport to reflect the views of the Commission nor should any party to said proceeding consider the Commission as bound in any manner by the statements or recommendations set forth herein. The Staff Report, however, is legally cognizable evidence upon which the Commission may rely in reaching its decision in this matter. (See Lindsey, et. al. v. PUC, 111 O.S. 6)

Respectfully submitted,

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Background

On July 6, 1999, Ohio Governor Bob Taft signed into law legislation providing residents of Ohio with a choice of electric generation suppliers. The new law provides customers with the choice of electric generation suppliers starting January 1, 2001. The new legislation also required an electric utility supplying retail electric service in the state of Ohio to file a plan describing how the utility will provide electric service in this state during the market development period (2001-2005). The overall transition plan must include a rate unbundling plan, a corporate separation plan, a plan to address operational support systems and any other technical implementation issues pertaining to competitive retail electric service, an employee assistance plan, and a consumer education plan. The electric utility may also include in its plan changes to tariff terms and conditions to address reasonable requirements of changing suppliers, length of commitment by a customer for service, and such other matters as are necessary to accommodate electric restructuring. The plan may also include an application for the opportunity to receive transition revenues and a plan for the independent operation of the utility's transmission facilities.

On November 30, 1999, the Public Utilities Commission of Ohio (PUCO) issued its Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan in Case No. 99-1141-EL-ORD. The Commission issued an Entry on Rehearing on January 4, 2000, a Second Entry on Rehearing on January 27, 2000 and a Third Entry on Rehearing on February 17, 2000. Those rules identified the form of the transition plan filing, a PUCO policy on consumer education, and rules on corporate separation and independent operation of transmission facilities.

The PUCO and its Staff are currently working on numerous other rules that were required by the new legislation. These rules include Certification of Providers of Competitive Retail Electric Services (99-1609-EL-ORD), Nuclear Decommissioning (99-1610-EL-ORD), Minimum Competitive Retail Electric Service Standards (99-1611-EL-ORD), Market Monitoring (99-1612-EL-ORD), Electric Service and Safety Standards (99-1613-EL-ORD), Long-Term Forecast Reporting (99-1614-EL-ORD), and Alternative Dispute Resolution (ADR) (99-1615-EL-ORD). A complete list of the Staff's proposed rules is listed at the PUCO's Electric Restructuring Web site (http://www.puc.ohio.gov/CONSUMER/ restructuring/proposed_rules.html).

The Dayton Power and Light Company (DP&L) was incorporated in 1911 as an Ohio corporation and is a combination electric, gas and steam public utility[1]. DP&L provides electric energy generation, transmission, and distribution services to approximately 500,000 customers in all or part of 24 counties in west central Ohio. On December 20, 1999 DP&L filed its electric transition plan. In addition to its application, DP&L filed a rate unbundling plan, a corporate separation plan and a code of conduct, an operational support and technical implementation plan, an employee assistance plan, a consumer

[1] On December 15, 1999, DPL Inc. announced an agreement with Indiana Energy Inc. to sell its natural gas distribution business.

education plan, an application for the authority to collect transition revenues, an explanation of DP&L's intent with regard to the independent operation of its transmission facilities, a shopping incentive plan, tariff terms and conditions necessary to accommodate electric restructuring, an explanation of deferred issues, and supporting materials. DP&L held a technical conference on January 11, 2000 to explain the structure of the filing, the work papers, the data sources, and the manner in which calculations were made. On or before February 3, 2000, several parties filed preliminary objections to the plan.

Scope of the Staff's Investigation

The scope of the Staff's investigation was designed to determine if the Transition Plan filed by DP&L meets the applicable requirements of Chapter 4928, Revised Code. The scope of the investigation was also designed to determine compliance with the PUCO's consumer education policy, PUCO proposed corporate separation rules, PUCO proposed rules for the independent operation of transmission facilities, and any applicable Staff proposed rules required to be implemented by the new legislation. This report identifies the Staff's exceptions to the electric utility's transition plan, generally explains the basis or bases for each exception, and provides recommendations to correct those exceptions. The recommendations reported herein are only for those items for which Staff identified an issue or for which Staff objects. This Report will not recount, describe, discuss, or evaluate every item or topic or process proposed in the Application for which there is no alternative Staff recommendation.

The Staff reviewed all of the documentation filed by DP&L, issued data requests, conducted investigative interviews, and performed independent analyses when necessary. The Staff also reviewed all of the objections and documentation filed by the intervening parties. The Staff hired an independent consultant, Resource Data International, Inc., to determine a market valuation of each utility's generation plant. The results of that investigation are generally discussed in this report. The Staff also requested the assistance of the Ohio Department of Development (ODOD) to perform the audit required by Section 4928.51(D), Revised Code to establish a baseline for Percentage of Income Payment Plan Program that will be used as a rate for the Universal Service Rider. The results of that audit will be included in the ODOD consultant's report.

The Staff's exceptions and recommendations to the Applicant's proposed restructuring plans are generally discussed below. The exceptions and recommendations are organized by Parts A through H similar to the application. The Staff has also included an additional Part I - Structural Impediments.

This report includes several exceptions that note that there is a data request pending or the investigation is continuing. Due to time restraints, Staff has not fully completed its analyses of all issues. Some responses to data requests were late. In some instances, data requests were sent late in the process, or, the answers to earlier data requests generated further questions. This is not meant to indicate that the Applicant was uncooperative in any way. To the contrary, Applicant personnel have, on numerous occasions, made themselves available to Staff for explanations regarding the application. As the analyses are completed, issues may be fully resolved prior to testimony.

The Staff would like to commend the Appplicant for the organization and detailing of its application. The testimonies, schedules, and supporting workpapers were well organized and descriptive. The entire application was supported by electronic versions that were very helpful during the Staff's review.

Part A – Rate Unbundling Plan

Introduction

Section 4928.31(A)(1), Revised Code mandates that transition plans include a rate unbundling plan consistent with Sections 4928.34 (A)(1) through (A)(7). The PUCO established a set of filing requirements for the unbundling plan by its Order and Entries on Rehearing issued in Case No. 99-1141-EL-ORD.

Summary Description of the Applicant's Unbundling Proposal

In its filing the Applicant has unbundled the rates that were in effect on October 5, 1999. The base rates that were in effect on October 5, 1999 were approved in Case No. 91-414-EL-AIR. The Electric Fuel Component Rate (EFC) was approved in Case No. 98-105-EL-EFC. The Percentage of Income Payment Plan rates (PIPP) was approved in Case No. 99-751-GE-PIP. The Emission Fee Allowance Rider was approved in Case No. 93-1001-EL-EFR on August 19, 1999.

The current bundled rates of the Applicant were unbundled into the following components: Distribution Charge, Transmission Charge, Ancillary Service Charges, Regulatory Transition Charge, Customer Transition Charge, Universal Service Charge, Energy Efficiency Charge, Emission Fee Rider and a Generation Charge. In addition, the Applicant has proposed changes to its standard terms and conditions of electric service.

To unbundle its current rates the Applicant utilized the Cost of Service Study (COSS) from its last rate case. The COSS was adjusted to reflect the Stipulation that was filed in that case. Based on that COSS, the Applicant unbundled its COSS into production, transmission and distribution.

Following the functionalizing to generation, transmission and distribution, the Applicant unbundled rates into the components previously described. As required by Section 4928, Revised Code, the Applicant developed its transmission rates based on its Federal Energy Regulatory Commission Open Access Transmission Tariff (FERC OATT). The distribution rates were derived by subtracting the FERC OATT revenue requirement from the transmission and distribution revenue requirement as determined by the Applicant's COSS.

The ancillary charges were unbundled from either generation or transmission depending on where they were contained in the COSS. From generation, the Company unbundled a Regulatory Asset Transition Charge revenue requirement that was to be developed based on the regulatory assets that are currently contained in base rates. The derivation of the total Customer Transition Charge revenue requirement will be discussed in Part F of this report, however, the allocation of such revenue requirement to the various classes and the rate design associated with the revenue requirements will be discussed in this section of the report.

The unbundled Universal Service Fund Charge is based on the portion of the PIPP rider that is related only to the on-going costs of the program. The remaining generation-related portion of the Rider has been included in the Applicant's regulatory asset calculation. The Applicant will update this charge when additional information is available concerning the administrative costs associated with program.

The Applicant has included an estimated Energy Efficiency Fund Charge. The Applicant will update this charge when the appropriate amount is determined.

Finally, the unbundled generation component is determined by taking the total bundled rate component and subtracting the items discussed above. Tax-related adjustments and the five-percent residential reduction, as mandated by Chapter 4928, Revised Code, were then made to the unbundled rates. In addition, the Applicant increased its Customer Transition Charge to recover items associated with tax overlap issues and employee assistance costs.

Staff's Exceptions and Recommendations

The order of the exceptions in Part A will be provided in the same manner as the UNB schedules that were required in Section 4901:1-20-03, Appendix A, Section (F), followed by a discussion of those exceptions that may not fall under the UNB Schedule categories.

UNB-1 – Proposed Tariff Language

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed UNB-1 schedules that provide a scored copy of the proposed tariffs. This section identifies Staff's exceptions to the proposed language for the General Service Rules and Regulations, proposed language changes to existing schedules and the proposed language in the new schedules.

The Applicant has redesigned its tariffs to include a separate tariff for Distribution, Transmission and Generation. Each section contains general terms and conditions followed by the various rate schedules. Following are the exceptions that Staff has identified for the UNB-1 schedules.

<u>Electric Distribution Service Tariff</u>

A-1. On Original Sheet No. D5, paragraph 8, the Applicant is eliminating language that states that it will, at the request of the customer, make a reasonable effort to determine the most favorable rate for any customer who qualifies for more than one rate schedule. The Staff recommends that this language remain in its filed tariffs.

A-2. On Original Sheet No. D7, the Staff recommends that the Applicant be more specific as to what the fee will be for providing hourly pulses to customers or an AGS.

A-3. On Original Sheet No. D12, the Staff takes exception to the fact that in its Rules and Regulations regarding the Extension of Electric Facilities, the Applicant has removed its existing provisions allowing non-demand metered customers an extension of two-hundred feet or less without charge and demand metered customers an extension of fourteen feet or less per kW of billing demand without charge. Such removal constitutes an increase in rates not contemplated by Senate Bill 3.

A-4. Original Sheet No. D34 provides requirements for customers switching to an alternative generation supplier. As written, these provisions would require the supplier to obtain written authorization from the customer. This requirement is inconsistent with Staff's proposed CRES Rule 6 (Customer Enrollment), which requires no written authorization for telephonic enrollment, nor does it require a signature for Internet enrollment. Staff recommends this provision be revised so as to be consistent with proposed CRES Rule 6 (consistent with the Commission's final ruling on the CRES rules, Case No. 99-1611-EL-ORD). Staff is also concerned that the Company's proposed $13 switching fee may be excessive, since it is much higher than the switching fees being proposed by the other EDU's. Staff believes such a high fee will inhibit many customers from switching, and recommends the proposed switching fee be lowered to a level comparable to that of other EDU's.

<u>Alternate Generation Supplier Coordination Tariff</u>

A-5. In Section 2.1 (on page 5) of Original Sheet No. G8, the Applicant proposes that a $1,000 registration fee be required of alternate generation suppliers. Staff considers this amount excessive given that the other Ohio EDUs are proposing much lower fees of this type. Staff believes such a high fee constitutes a market barrier, which may inhibit CRES providers (especially the smaller ones) from even attempting to do business in the Applicant's service territory. Staff recommends the proposed registration fee be lowered to a level comparable to that of the other EDU's.

A-6. Section 4.5 (a) of Original Sheet No. G8 states the Applicant's procedures for handling customer moves within DP&L's service territory. Some parties are discussing this issue in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

A-7. In Original Sheet No. G8, Section 9, the Applicant requires customers with billing demand over 25 kW to install hourly metering at their own expense if they wish to be served by an alternate generation provider. Some parties are discussing this issue in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

A-8. In Original Sheet No. G8, Section 11.2, the Applicant denies the budget-billing option to customers who choose a CRES provider. Some parties are discussing this issue in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

A-9. In the second paragraph of Original Sheet No. G8, Section 11.9, the Applicant requires a minimum deposit of $500,000. Staff believes this amount is excessive to the extent it exceeds a CRES provider's actual liability to the Company. Such excess would occur in the case of CRES providers with a small customer base or who serve only a small generation load. Staff considers such excess a market barrier since it would tend to inhibit small CRES providers from doing business in DP&L's service territory. Staff recommends this tariff provision be revised to limit deposits to the amount needed to cover the CRES provider's actual liability to DP&L.

A-10. In Original Sheet No. G8, Section 13.2, the Applicant requires CRES providers to give 60-day's prior notice to any customer it intends to stop serving. Staff believes this is too long a notice requirement in customer nonpayment situations (where EDUs are only required to give from 14 to 21 day's notice prior to disconnecting their customers). Staff recommends that this tariff provision be changed to be consistent with the notice period provided in proposed CRES Rule 12 (Contract Disclosure). Situations other than customer nonpayment and abandonment of service (see proposed Certification Rule No. 12) are topics of discussion at the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

A-11. On page 28 of Tariff G8, the Applicant would charge a CRES provider $10.00 for each customer's 12-month historical usage data requested, and then only if the customer had authorized such disclosure. Requiring such customer consent would be contrary to the requirements of Section 4928.10 (G), Revised Code which requires providers to make customer-specific load pattern information available unless a customer objects. Some parties are discussing this issue in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

<u>Competitive Retail Generation Service</u>

A-12. On page 1 of its proposed Original Sheet No. G9, the Applicant prohibits its standard-offer customers with outstanding DP&L debts from choosing an alternative generation supplier. This prohibition seems to discriminate against standard offer customers since it is not applied (or even permitted by the legislation) against customers with outstanding CRES provider debts. Staff recommends this provision be eliminated, while preserving the Company's right to disconnect service for non-payment of regulated charges, including those for standard offer service.

A-13. Also on page 1 of Original Sheet No. G9, the Applicant requires customers who choose a CRES provider to remain on CRES for at least one year. This requirement appears to be inconsistent with Staff's proposed CRES Rules, which prescribe no minimum term for AGS customer contracts. It also appears contrary with the Company's status as a provider of last resort. A customer's CRES provider may cancel the customer's contract for non-payment, and such a customer may not be acceptable to other CRES providers. Staff recommends this tariff provision be revised to omit the minimum time requirement for remaining on CRES.

A-14. Original Sheet No. G9 requires customers to contact the AGS provider in order to enroll, and adds that if the customer contacts DP&L with such a request, the Company will merely instruct the customer to contact an AGS provider. Staff believes EDU's need to provide customers more assistance in shopping for a CRES provider. Staff recommends the tariff be revised such that DP&L would furnish the customer with a complete and up-to-date list of PUCO-certified and DP&L-approved AGS providers and their toll-free telephone numbers.

A-15. Original Sheet No. G9 repeats the Applicant's requirement for certain customers to pay for hourly meters if they want to be served by AGS providers. Some parties are discussing this issue in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.

<u>Electric Generation Service Tariff (Standard Offer)</u>

A-16. Net Metering – The Applicant has failed to include a Net Metering tariff as mandated by Section 4928.67, Revised Code. It is the Staff's position, based on its understanding of that provision, that although CRES providers would implement the requirement by developing standard net metering contracts, EDU's would implement the requirement by developing uniform net metering tariffs. Staff recommends the Company develop and file such a tariff within 30 days of the Commission's order in this case.

<u>Other Tariff Issues</u>

A-17. The Staff recommends that the Applicant make reference in its filed tariffs to the fact that if a retail customer or its supplier seeks a backup electricity supply from DP&L or a self-generator seeks access to backup service from a competitive electric generation service provider, that the company will address such a request on a case-by-case basis.

UNB-4 - Cost of Service Study

The Applicant's cost of service study (COSS) UNB-4 presents its determination of unbundled cost components. The stipulation in the Applicant's last rate case, Case No. 91-414-EL-AIR, established levels for operating revenue, operating expenses, rate base, rate of return and return on equity (See WP4H, Exhibit A). The revenue increase from that stipulation was phased in over three years (See WP4H, Exhibit B).

From the amounts authorized in the stipulation and the total revenue increase due to the phase-in, the Applicant made "educated guesses" as to how to adjust or apportion the revenue, expense and rate base amounts to the categories that made up those amounts. This was based on Case No. 91-414-EL-AIR unadjusted test year as the starting point for revenues and expenses, and the date certain as the starting point for rate base items. The adjustments were based on the difference between amounts determined in Phase III of the stipulation and the unadjusted test year / date certain (See WP4C).

The Applicant next functionalized rate base and operating expense (with the exception of income tax expense) amounts. The basis for separating these costs to their functional components was the COSS filed in the Applicant's last rate case. The Applicant then allocated the functionalized amounts to the rate schedules.

The Applicant developed income tax and operating revenue amounts by an iterative process of working the revenue requirement calculation in reverse. This was accomplished using the rate base and operating expenses determined above along with a rate of return developed for each rate schedule.

The Staff verified the flow of information from the Applicant's filing, stipulation and phase-in calculation to the summary and supporting pages in the current application. The Staff also verified the Company’s class allocation factors by randomly selecting various accounts and rate classes.

A-18. The Staff was not able to replicate and verify the Applicant's process for determining functional amounts for revenues and income taxes. The Staff is in the process of investigating this issue and, if necessary, will further address this issue in testimony.

Seven-Factor Test

A-19. According to the transition rules as found in Section 4901:1-20-03 Appendix A, Unbundling Plan (F)(2)(g) Cost of Service Study, each of the electric utilities are required to “demonstrate that the facilities included for cost recovery in the transmission component are consistent with the FERC seven-factor test.” Dayton Power and Light did not conduct the seven-factor test analysis and identify specific transmission assets as part of its transition plan filing. Dayton Power and Light also did not report the cost of service requirements reflecting the refunctionalization.

Section 4901:1-20-03 (F)(2)(g) was written so that the physical separation of transmission and distribution assets would be made for ratemaking purposes. Because of the way Chapter 4928, Revised Code is written, the transmission and distribution rates are somewhat fixed during the market development period. The law states in Section 4928.34(A)(1) that the unbundled transmission component for the utilities' unbundling plan shall equal the tariff rates determined by the FERC. The physical separation is however essential for post-market development rate implications and can be argued necessary during the market development period for the sake of determining charges for the use of specific facilities when specific power transactions take place.

The identification of separate transmission and distribution assets in Ohio, and the appropriate associated costs, should be identified now so that a more accurate unbundling of rates can occur and to comply with the rule requirements as found in Section 4901:1-20-03 (F)(2)(g). Recognizing the time requirements for such an endeavor, the Applicant should be required to begin the process and file with the Commission in this transition plan docket the necessary data and justification to separate transmission from distribution facilities. The justification should include the seven-factor test and appropriate load-flow studies to support the seven-factor test analysis and the associated cost of service requirements for what is identified as transmission and distribution.

UNB-5 Unbundled and Unadjusted Rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-5 schedules for the purpose of unbundling the current bundled rates as provided in the UNB-3 schedules. The Applicant utilized the UNB-5 schedule to unbundle its rate schedules to Production (Generation), Transmission and Distribution.

Following is a discussion of the Staff 's exceptions to the Applicant's filed UNB-5 schedules.

<u>Determining the generation component</u>

In its application, the Applicant has treated generation, which Staff refers to as "little g" ("little g" = G-RTC-CTC) as a residual amount. The Applicant has calculated a specific CTC revenue requirement amount to be collected annually over a four-year period. In addition, it has calculated the RTC revenue requirement for each class, which is to be the amount of regulatory assets in current base rates. To determine "little g", the Applicant has taken the total revenues and subtracted all components discussed above, including the CTC and RTC, and the remaining revenues are considered "little g".

A-20. If it is determined that the Applicant has CTC to recover, the Staff recommends that the CTC rate for each rate schedule be determined by taking the generation revenue requirement (GTC, RTC and "little g") for each schedule and subtracting the revenue requirement associated with the market rate and the

RTC revenue requirement. The CTC and RTC revenue requirement as well as the revenue requirement for the energy portion of "little g" should be allocated through the energy blocks on a consistent basis. Unbundled unadjusted rates per block within each rate schedule are made equal to the current rates per block by making the total generation rate, which includes CTC, RTC and "little g", the residual amount.

RTC Allocation to the classes

A-21. In its application, the Applicant has allocated its RTC to the various classes based on how each element of the RTC is currently allocated to each class in the current bundled rates. However, based on Workpaper WPTC1D.1, to allocate the total RTC Balance, as of December 31, 2000, to the various classes, the Applicant utilized an energy allocator. Therefore, the method for determining the actual RTC rate for each schedule is appropriate, but the method for determining how much needs to be collected from each class in total is not appropriate. Staff recommends that the RTC balance, as of December 31, 2000, be allocated to the classes on the same basis that they are currently allocated in base rates.

Unbundled Distribution Rate Development Issues

The Applicant's unbundled Distribution rates were designed by developing a revenue requirement for transmission and distribution from the Cost of Service Study (COSS) and subtracting from that revenue requirement, the transmission revenue requirement based on the Applicant's FERC OATT. The remaining revenue requirement is considered distribution revenue and rates were designed to recover such revenue. The Applicant further adjusted the distribution rates to include the transmission and distribution portion of the deferred PIPP arrearages[2].

A-22. While Staff does not disagree that there may be transmission and distribution related deferred PIPP arrearages, the application was unclear as to the rationale for including such costs in the distribution base rates. Generally, PIPP is collected through a Rider so that it may be adjusted or terminated when the appropriate amount of funds has been collected. By placing these costs in the base rates, there will be no opportunity for adjustment or elimination until the Applicant comes before the Commission with a distribution rate case. Staff recommends that the Applicant provide sufficient rationale for including this charge in the Distribution base rates within thirty days of the issuance of this Staff report.

[2] The Applicant separated the current PIPP rate into three components. The first component is associated with on-going PIPP costs and was shifted to the USF rider. The deferred PIPP balance was then separated into generation-related and transmission / distribution- related deferred PIPP.

UNB-6 Adjustments to current rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-6 schedules in its transition plan filing. The UNB-6 schedules provide details of the adjustments that were made to the rates in accordance with the new tax laws and the mandated 5% residential reduction as prescribed in Chapter 4928, Revised Code. Following are the exceptions that Staff has identified with the Applicant's treatment of the tax-related changes and other changes the Applicant is proposing.

<u>Property Tax</u>

The tax on Zimmer inventories (fuel, materials and supplies) was calculated by applying the statutory 25% assessment factor to the true value to determine the taxable value. The calculation for the average tax rate in this proceeding (0.0547) was not provided. This is the same rate that was used in the Zimmer personal property tax calculation and represents the average rate for production plant. The rate is different from that which was used in the last rate case proceeding (0.0609).

A-23. A calculation of the average tax rate applicable to inventories (TAB: WP6B.1, page 6 of 8) was not included in the filing. The Staff recommends the Applicant provide the derivation of the rate that was utilized including supporting rationale.

<u>Excise Tax Surcharge Rider</u>

A-24. The Applicant is proposing to put an Excise Tax Surcharge Rider into effect beginning January 1, 2001 and extending through April 30, 2001. The Applicant is proposing to include a grossed-up effective tax rate of 4.98%. The Staff recommends that the Applicant include the effective gross receipts tax rate net of uncollectibles and non-taxable receipts.

<u>5% Residential Reduction</u>

A-25. The Applicant has adjusted rates for residential customers by applying a 5% reduction to "little g" prior to tax-related adjustments. Staff believes that the intent of the legislation in Section 4928.40 (C), Revised Code was for residential customers to receive a 5% reduction on the Generation portion of their rates, which would include "little g" as well as the CTC and RTC. In addition, such reduction should be applied to the generation component subsequent to tax-related adjustments.

<u>Additional CTC Items</u>

A-26. In its filing the Applicant has developed a monthly CTC rate for each rate schedule to recover a specific amount of transition costs. The Applicant's residual generation amount is based on the initial calculation of its CTC. However, at the same time the Applicant is adjusting rates based on tax-law changes, which allow for an adjustment in the capped rates, the Applicant is also adjusting its CTC rate to include two additional items[3]. This results in an increase in the current bundled rates. Without making a specific recommendation as to the appropriateness of including the costs in the initially determined CTC calculation, Staff recommends that to the extent that such costs should be considered for recovery, they should not increase current bundled rates.

UNB-7 Adjusted and Unbundled Rates

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed UNB-7 schedules in its transition plan filing. The UNB-7 schedules were to reflect the final rates the Applicant is proposing in its UNB-1 schedules.

Due to the mechanics of unbundling rates as mandated, it is impossible, at this time, for Staff to make recommendations as to the "correct" rate levels. Many rates are determined on a "residual" basis; thus, a change in one component results in changes to other components. Therefore, exceptions and Staff recommendations are based more on the "methodology" of unbundling, rather than precise rate levels.

UNB-8 Typical Bill Comparisons

In accordance with Rule 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-8 schedules in its transition plan filing. The residential proposed bills include the effects of the mandated 5% residential reduction.

A-27. In reviewing the UNB-8 schedules, the effects of the tax-related adjustments become apparent. For example, looking at the Applicant's GS Secondary Schedule (3-phase), page 8 of 13, on lines 8 and 9, the effect of the tax law changes are apparent. On line 8, the customer will experience a .8% increase, while on line 9, a customer with the same demand but more consumption (higher load factor) will receive a much higher rate increase of 4.9%. This is a result of property taxes being removed from rates based on how they were included in rates in the last rate case, and then a new tax being levied on only the kWh consumption rates. This results in more taxes being collected through the energy rates than the demand rates, therefore, creating adverse impacts for higher load factor classes and customers. Staff recommends that the Applicant, when designing its rates that include the tax-related adjustments, take into consideration the resulting typical bill impacts for all customers.

[3] The Applicant is requesting approval to increase its initially developed CTC to include costs related to a tax-overlap issue and employee assistance costs.

Other Issues Not Addressed in the UNB Schedules

A-28. The Commission's Second Entry On Rehearing in Case No. 99-1141-EL-ORD issued on January 27, 2000 requires that dollar amounts in the current bundled rates associated with metering services and billing and collection services be "identified". The Applicant should provide the identification of those amounts within thirty days of the issuance of this report, as well as provide arguments as to whether those services should or should not be unbundled portions of the distribution function.

Part B - Corporate Separation Plan

Introduction

Section 4928.17(A) of the Revised Code set out three primary objectives for Corporate Separation plans. These objectives as summarized are:

- Providing for the provision of competitive retail electric service or the non-electric product or service through a fully separate affiliate, with separate accounting requirements and a Code of Conduct as ordered by the Commission;

- Satisfying the public interest in preventing the abuse of market power;

- Ensuring no undue preference or advantage is extended to any affiliate, division or part of the business engaged in supplying competitive retail electric service or a non-electric product or service.

Summary Description of the Applicant's Corporate Separation

DP&L (the distribution/ transmission company) plans to comply with the corporate separation rules, by establishing separate corporate entities for electric generation, distribution/transmission, and non-electric products or services. Operational control and beneficial ownership of associated assets for each service will be transferred to the separate corporate affiliates on or before January 1, 2001. DP&L believes it can transfer the generation assets by leases or other contractual arrangements that fully separate control of the assets from DP&L. However, DP&L believes that actual title of the generation assets must remain with DP&L, during a currently undefined interim period, because of indenture requirements on outstanding first mortgage bonds, and transfer restriction on DP&L's preferred stock issuances. The generation company will assume the ongoing obligations as well as a share of the existing liabilities.

The Company stated that its corporate separation plan will be implemented by using a two step process with a transitional step (exhibit 2) being used during 2000 (please see organizational charts, exhibits 1-3). It should be noted, DP&L Inc., (DPL), on December 15, 1999, announced an agreement with Indiana Energy Inc., to sell its natural gas distribution business for $425 million. In addition, DP&L announced that it will be issuing up to $975 million of trust pre and senior unsecured securities to repurchase about 20% of the outstanding common shares, retire short-term debt, and invest in peaking generation assets. As part of the recapitalization, an affiliate of Kohlber, Kravis and Roberts (KKR) will make a strategic investment in DP&L through the placement of $550 million of preferred securities.[4]

[4] Standard & Poor's wire reports 2/2/00.

Staff believes that the relationship between DPL and KKR could cause the current separation plan and the general organization of DPL, to be altered. KKR, traditionally takes an active role in attempting to increase the value of its associated companies, often radically changing the current (or this case planned), corporate structure.

DP&L currently has the following affiliates which conduct businesses as described below:

1. Miami Valley Leasing, Inc. leases communication and other equipment, owns real estate and has, for financial investment purposes, acquired limited partnership interests in wholesale electric generation;

2. Miami Valley Resources, Inc. is engaged in the natural gas supply management business;

3. Miami Valley Lighting, Inc. operates a lighting business;

4. DPL Energy, Inc. has been granted the authority to engage in the business of brokering and sale of wholesale electric energy and is developing peaking generation;

5. Other subsidiaries include MacGregor Park Inc. (real estate), Miami Valley CTC Inc. (transportation), Miami Valley Development Company (real estate), Miami Valley Insurance Company (insurance), and MVE, Inc. (support services).

Interim Functional Separation

Attachment I to the Commission Finding and Order 99-1141-EL-ORD (pg. 43-44), states that except as the Commission may approve, the financial arrangements of an electric utility are subject to certain restrictions.[5] These restrictions seek to among other things, eliminate the exposure to the electric utility based on actions of a competitive business, and require the competitive businesses to obtain financial arrangements which better reflect the risk of their business. However, the Staff recognizes that under the previous regulatory structure the electric utilities, in an attempt to lower their cost of capital entered into some arrangements which would be in violation to the current rules. These arrangements include pollution control notes and mortgage bonds. Pollution control

[5] The restrictions are as follows:
a. Any indebtedness incurred by an affiliate shall be without recourse to the electric utility.
b. An electric utility shall not enter into any agreement with terms under which the electric utility is obligated to commit funds to maintain the financial viability of an affiliate.
c. An electric utility shall not make any investment in an affiliate under any circumstances in which the electric utility would be liable for the debts and / or liabilities of the affiliate incurred as a result of actions or omissions of an affiliate.
d. An electric utility shall not issue any security for the purpose of financing the acquisitions, ownership, or operation of an affiliate.
e. An electric utility shall not assume any obligation or liability as a guarantor, endorser, surety or otherwise with respect to any security of an affiliate.
f. An electric utility shall not pledge, mortgage or use as collateral any assets of the electric utility for the benefit of an affiliate.

notes lower the cost of capital because they are not taxable and mortgage bonds are bonds secured, often through liens, against general plant and / or equipment, giving the investor added security that the payment will be met.

While the Staff continues to believe that DP&L should separate their financial arrangements as quickly as possible, some flexibility maybe warranted. If, for example, the Commission required immediately (or even on or before a specified date) that DP&L tender[6] its first mortgage bonds, it could increase costs dramatically, due to potentially poor market conditions and maybe more importantly, a strengthened negotiating position for the bond holders. These additional costs could substantially increase transition charges. It should be noted that the electric utility is not permitted to simply purchase the first mortgage bonds on the open market because of SEC requirements, which entails being fair to all classes of bond holders.

The Applicant, as required in Section 4928.17(A) of the Revised Code, submitted a code of conduct in its transition plan. The code of conduct has minor differences from the Commission's Rules.

Exceptions and Recommendations

1. The Staff believes it may be prudent to allow DP&L to use an interim functional separation plan, due to some of its current financial arrangements. However, during this time of functional separations, additional monitoring is warranted, with particular attention being paid to the cost of capital of each entity, such that it reflects the market risks of the business. For example, DP&L, with its guaranteed cashflows should experience a significantly lower cost of capital.

[6] A tender offer is an offer to buy, in this case first mortgage bonds, at a stipulated price, usually substantially above market price, so that the bonds may be redeemed.

Part C – Operational Support System Plan

Introduction

Section 4928.31(A)(3), Revised Code and the PUCO's rules require each electric utility to file an operational support plan as part of the overall transition plan. The operational support plan outlines areas required to implement customer choice in Ohio, including a timetable and work plan for development of the systems to permit certified suppliers and companies to handle customer information in an efficient manner.

Summary description of the Applicant's Operational Support Plan

The Company proposes an operational support plan that is structured to meet the requirements of 4901:1-20-03 Appendix B of the Commission's rules and with the policy goals pursuant to Section 4928.02 Revised Code. The plan refers to the overall management and operations to be performed by the Company to provide electric service to its customers for competitive retail electric services. All portions of the Company's proposed plan are set forth in great detail in its "NOTICE OF PROPOSED RESTRUCTURING PLAN OF THE DAYTON POWER AND LIGHT COMPANY". Mr. Costello and Ms. Reives have overall responsibility to manage the customer choice process. The plan is further described in the testimony of Company witness Ms. Seger-Lawson.

Staff Exceptions and Recommendations

The staff is currently conducting a series of workshops to address some of the issues that are related to operational support. Recommendations from those workshops will be presented to the Commission when they are available. The staff finds no specific exceptions or recommendations to the Company's proposed operational support plan.

Part D - Employee Assistance Plan

Introduction

Section 4928.31, Revised Code required each Applicant to file employee assistance plans as part of their overall transition plans. The plan is to identify any employee assistance that will be offered to employees whose employment is affected by electric industry restructuring. The PUCO has adopted rules for electric utilities to follow when preparing their employee assistance plans. These rules also overlap with the transition charges rules contained in the Administrative Code, Section 4901:1-20-03, the Revised Code Section 4928.37 and Section 4928.40 and Appendix D of Case No. 99-1141-EL-ORD. Certain employee assistance costs are eligible for transition cost recovery.

Section 4928.431, Revised Code created an Employee Assistance Advisory Board for the purpose of making recommendations to the PUCO after review of the transition plan filings made by each Applicant. The Employee Assistance Advisory Board has not been appointed.

Summary Description of the Company's Employee Assistance Plan

Dayton Power and Light (DP&L) states it does not have proposed staffing changes at this time. Dayton Power and Light, through its Plan and witness, Mr. William L. Mercer, describes how it would implement its downsizing plan if it becomes necessary. Dayton Power and Light would first consider retention, training and re-education programs as outlined in the Plan and testimony. If employees could not be placed within the company through these efforts, Dayton Power and Light would enact an involuntary workforce reduction and utilize efforts described in the Plan and testimony such as outplacement service, training, severance and early retirement.

Employees that are affected by restructuring would be eligible for the company's employee assistance plan (EAP).

Exceptions and Recommendations

The Staff is ready to assist the Employee Assistance Advisory Board with any technical assistance that Board may require. The board's relationship with Staff is not identified; therefore, any relationship will be developed on an ad hoc basis. Staff does not have any specific exceptions or recommendations to Dayton Power and Light's employee assistance plan.

Part E - Consumer Education Plan

Introduction

The Ohio Electric Restructuring Act of 1999 contains several provisions for consumer education to ensure that consumers understand the options they will have -- and the buying decisions they will have to make -- in a competitive electricity marketplace.

Recognizing the scope of this challenge, the law directs the state's investor-owned electric companies to spend up to $16 million for statewide and local consumer education programs prior to and during the first year of electric competition, which begins January 1, 2001, and an additional $17 million thereafter during the transition period.

On November 30, 1999, the PUCO adopted The General Plan for Consumer Education. This plan divided the total consumer education campaign into a two-pronged effort, calling for a statewide campaign and a service territory-specific campaign. The total $33 million was divided in the plan for first year spending of 70% for the statewide campaign and 30% for the local service territory efforts by each of the utility companies. Thereafter, the funding allocation is 40% for the statewide effort and 60% for the local efforts.

The Public Utilities Commission of Ohio (PUCO), in consultation with the Ohio Consumers' Counsel (OCC), will oversee this consumer education project. The Ohio Electric Utility Institute (OEUI), the trade association for the state's investor-owned electric utilities, will administer the day-to-day implementation of the statewide consumer education program and coordinate these statewide activities with the local educational efforts of the individual electric companies. While the PUCO will work with the OCC and the OEUI on the consumer education project, the PUCO provides ultimate approval for the content and conduct of the campaign.

The General Plan for Consumer Education required that the utilities provide the following information as part of their Transition Plan filings: contact information for the lead on the project, plans for the creation of an advisory group, the general tactics the utility is anticipating utilizing, a timeline for implementation and a general budget.

Summary Description of the Company’s Consumer Education Plan

Dayton Power and Light (DP&L) proposes a Consumer Education Plan that includes a statewide campaign undertaken and directed by the PUCO and administered through the Ohio Electric Utility Institute and a local campaign direct to service area customers. The Consumer Education Plan is intended to increase awareness, particularly in the residential and small commercial classes of the customer choice program and to provide customers information on how to participate. Statewide and local advisory groups will provide input into the statewide and local campaigns.

DP&L's contact for the program will be Thomas Tatham, manager of corporate communications for the company. DP&L proposes to establish an advisory group made up of a Staff representative, OCC representative and possible representatives of consumer groups, senior groups, business organizations, human services organizations, low income agencies and environmental agencies. The advisory group is scheduled to meet quarterly to provide input regarding the goals and messages of the campaign. Staff will work with DP&L to ensure that the group meets often enough to have meaningful input.

DP&L proposes to utilize tactics including paid advertising, direct mail, bill inserts, collateral materials, promotional event presentations and news releases. The schedule and frequency for implementing these tactics would be developed after benchmarking surveys have been done. DP&L also proposes to provide free information to community groups for distribution and is compiling a list of such groups in the service area that may be of assistance in distributing the information.

DP&L proposes to begin the service territory-specific campaign after the statewide campaign kicks off in July 2000. However, DP&L outlines a general timeline of activities in their campaign.

DP&L proposes to provide $1.8 million, or 10%, of the first year $16 million for consumer education and $1.8 million thereafter for the remaining transition period.

Exceptions and Recommendations

The Staff is, and will continue to work with each of the utilities to further develop their plans as well as ensure the messages are un-biased and supportive of the statewide effort. DP&L's proposed advisory group is lacking representation of the energy marketers, but Staff will work with the company to bring this issue into compliance with the General Plan for Consumer Education. Otherwise, DP&L's plan for consumer education is consistent with the General Plan for Consumer Education. Staff does not have any specific exceptions or recommendations to DP&L's plan for consumer education.

Part F – Transition Costs, Revenues, & Charges

Introduction

Transition costs are identified in Section 4928.39, Revised Code. Under that section, transition costs must meet all of the following criteria:

- The costs must have been prudently incurred.
- The costs must be legitimate, net, verifiable costs which can be directly assigned or allocated to Ohio.
- The costs must be costs that the utility could not recover in a competitive market.
- The costs must be costs that the utility would otherwise be entitled an opportunity to recover.

In addition to identifying these criteria, Section 4928.39(D) Revised Code explicitly includes costs associated with the employee assistance plan described in Section 4928.33, Revised Code, to the extent that those costs exceed the costs contemplated in labor contracts in effect on the effective date of the restructuring statute.

Under the requirements of Section 4928.39, Revised Code, a utility filing an approved transition plan is eligible to receive the costs identified above as transition revenues.

Section 4928.37 of the Revised Code identifies two mechanisms for the recovery of transition revenues. Transition revenues are received by the utility through the payment of unbundled rates for retail electric services by those customers who receive their generation service from the electric distribution utility, and from the payment of a non-bypassable and competitively neutral transition charge by each customer who receives generation service from a competitive supplier. The structure of that transition charge is detailed in Section 4928.40, Revised Code.

Section 4928.39(D), Revised Code requires the Commission to separately identify regulatory assets within the total transition costs determined, to be recovered through a separate charge, generally identified within this document as a Regulatory Transition Charge or RTC. The transition charge through which the utility may receive the remainder of the transition revenues is referred to in this report as the Competitive Transition Charge, or CTC.

Summary Description of the Applicant's Transition Revenue Plan

Generally speaking, DP&L's Transition Revenue Plan follows the design outlined in the introduction to this section. However, the Staff has found numerous areas where the Staff feels that DP&L has deviated from the intended structures, methodologies, and outcomes contemplated by Sections 4928.31 through 4928.40, Revised Code. These deviations, and the Staff's exceptions to them and recommendations for resolution are outlined in the following section.

Staff's Exceptions and Recommendations

As noted earlier, the Staff has found in its review numerous deviations from the structures, methodologies and outcomes contemplated by Sections 4928.31 through 4928.40 of the Revised Code. The Staff's discussion of these deviations is divided into Methodological Exceptions, Determination of Costs not Recoverable under Competition, Identification of Regulatory Assets, and Development of RTC Rates. This section concludes with a discussion of DP&L's proposed accounting authorizations.

Methodological Exceptions

As proposed by DP&L, the various rates and charges contemplated by Section 4928, Revised Code are calculated in the following manner:

- The existing rates are unbundled by a process of successive subtraction, in stages.
- Distribution is determined by subtracting the revenues resulting from the application of DP&L's Open Access Transmission Tariff (OATT) from the transmission and distribution revenue requirements by tariff class from the last rate case proceeding.
- From the remaining amount, the Universal Service Rider and Emmission Fee Rider were subtracted.
- The regulatory asset charge (referred to as Regulatory Transition Charge, or RTC) is determined, per Section 4928.39, Revised Code.
- A determination was made by PHB Hagler Bailly of the "stranded generation costs" based on a discounted cash flow methodology.
- Based on this determination, a "Customer Transition Charge" (CTC) was calculated by applying a gross revenue conversion factor to the "stranded generation costs", and a revenue requirement was developed using a weighted cost of capital of 9.2% for a four year transition plan. This revenue requirement was then allocated to tariffs, based on the cost of service study. The Staff uses the term Competitive Transition Charge (also abbreviated CTC) to refer to this charge.
- After subtracting the Distribution, Universal Service Rider, Emission Fee Rider, RTC, and CTC from the bundled rates, the Transmission rate, determined based on application of the cost of service study to DP&L's OATT, is subtracted. Various ancillary service rates are also subtracted at this stage.
- Under DP&L's methodology, their proposed RTC and CTC appear to be considered "other unbundled components" as identified in Section 4928.34(A)(4), Revised Code.
- The remaining portion of the bundled rate, after all of the steps noted above. is termed by DP&L as a "Residual Generation Charge", and forms the basis of DP&L's standard offer rate.
- The reduction in residential rates described in Section 4928.40(C), Revised Code is calculated on the "Residual Generation Charge".
- The CTC is adjusted to reflect the impacts of employee assistance costs and tax timing issues.

- A shopping credit is separately determined based on DP&L's avoided cost for those customers who select an Alternate Generation Supplier (AGS). Customers who choose an AGS will pay the Residual Generation Charge, and will receive a shopping credit according to the seasonally adjusted avoided cost.

As the Staff understands Section 4928, Revised Code, the determination of the various components must proceed as follows:

- The existing rates are unbundled into Transmission & Distribution, Generation, and other charges, per Section 4928.34, Revised Code.
- The FERC Transmission rate is subtracted from the unbundled Transmission & Distribution rate to determine a Distribution only rate, as is discussed in Section 4928.34, Revised Code.
- The Generation component thus identified includes all costs related to the provision of bundled generation service, whether or not they relate to transition costs as identified in Section 4928.39, Revised Code.
- One of the criteria for determining transition costs is that the costs be unrecoverable in a competitive market [Section 4928.39(C), Revised Code]. Therefore, a reasonable way to determine the transition cost related component of unbundled rates is subtracting an externally identified market price for power for a given class of customers.
- From the transition cost related component of unbundled rates, the regulatory asset portion, as identified in Section 4928.01(A)(26), Revised Code, is broken out, as is required by Section 4928.39(D), Revised Code.
- Should the Commission determine that a shopping incentive is required in order to create an effective market during the market development period, the transition charges must be adjusted, as is described in Section 4928.40(A), Revised Code.
- The residential rate reduction described in Section 4928.40(C), Revised Code is to be calculated on the unbundled Generation component, including transition charges, as identified in the third bullet point, above.

Therefore, the Staff takes exception to DP&L's methodology for the following reasons:

F-1. The rates which are described in Section 4928, Revised Code as established for the recovery of transition charges are themselves a part of what Section 4928.34(A)(4), Revised Code describes as the "unbundled components for retail electric generation service".

F-2. The design and determination of the transition charges proposed by DP&L is contrary to the language in Section 4928.40(A), Revised Code identifying the need for a shopping incentive as a factor in determining appropriate transition charges.

F-3. Under Section 4928.40(A), Revised Code, the transition charges must be determined in a manner that takes into account the relevant market price of power for the individual classes of customers, and must take into account the shopping incentives required to generate an effective market during the market transition period. The methodology proposed by DP&L does neither.

F-4. DP&L's adjustment of the derived CTC for employee assistance costs and tax timing issues is inappropriate and inconsistent with Section 4928.40, Revised Code.

F-5. DP&L's calculation of the residential rate reduction described in Section 4928.40(C), Revised Code is inappropriate in that it applies the reduction to their "Residual Generation Charge", rather than to a proper unbundled generation figure.

Determination of Costs Not Recoverable Under Competition

F-6. Dayton Power and Light has estimated that its net investment in generation facilities, as of December 31, 2000, will be $971,316,000, which is approximately $288 per kilowatt of capacity. Dayton has also estimated the portion of this investment recoverable in a competitive market to be $736,225,000, or $218 per kilowatt of capacity. The remainder, 24.2% of the investment in generation facilities, is put forward as one of the components for receiving transition revenues.

Resource Data International (RDI), the Staff's consultant, is in the process of conducting an analysis regarding the economic capacity values of Dayton Power & Light's generating facilities. While further refinements of RDI's valuation models need to be undertaken, Staff's discussions with the consultants indicate that the economically recoverable values claimed by Dayton Power & Light are, in the opinion of RDI, very likely to be understated. The Staff thus takes exception to the valuations contained in the Transition Plans. The Staff will provide specific estimates of the recoverable value of DP&L's generation facilities in testimony at the time of hearing.

Identification of Regulatory Assets

Section 4928.01(A)(26), Revised Code defines Regulatory Assets as:

> ...the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards No. 109 (receivables from customers for income taxes) future nuclear decommissioning costs and fuel disposal costs as these costs

have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

F-7. The rate used to calculate carrying charges on regulatory assets is excessive and inconsistent with the risk associated with recovery of these regulatory assets.

F-8. The Staff takes exception to DP&L's calculation of FAS 109 costs. Based on the Staff's review, DP&L's calculations overstated the FAS 109 estimated costs for 1999 by approximately $11,000,000. Since the estimated costs of year 2000 are based on 1999 estimation, the Staff believes that its exception is also applicable to year 2000 estimated costs.

Determination of Other Items Recoverable Through CTC

F-9. Tax Timing Overlap Costs - DP&L has requested that a revenue requirement of $34,115,389 be included as a transition cost claiming that it represents an overlap in the taxes to be paid as a result of changes resulting from Amended Substitute Senate Bill 3. The Applicant bases its claim on its accounting for this item. The Staff recommends that this item not be included in the transition costs and not be deferred as a regulatory asset to be recovered by the distribution company after the market development period. These costs are recovered currently by the Applicant through its base rates.

F-10. To the extent that the tax timing overlap costs are deemed appropriate for inclusion, the rate used to calculate carrying charges is excessive and inconsistent with the risk associated with recovery of these transition costs.

F-11. The rate used to calculate carrying charges on generation related transition costs is excessive and inconsistent with the risk associated with recovery of these transition costs.

F-12. Employee Assistance Costs – DP&L requested inclusion of an estimated cost for employee assistance in transition costs. DP&L did not establish a cause and effect relationship between restructuring and the number of employees used on its estimate, as is implied by Section 4928.31(A)(4), Ohio Revised Code. In its estimate, DP&L did not establish that the costs are in excess of the labor contract in force on the effective date of Section 4928.39, Ohio Revised Code, as is required by that section. In addition, there is no indication that DP&L has any immediate plans to downsize its workforce due to restructuring. To the extent that such inclusion is unsupported, the Staff takes exception to it.

F-13. To the extent that the employee assistance costs are deemed appropriate for inclusion, the rate used to calculate carrying costs is excessive and inconsistent with the risk associated with recovery of these transition costs.

Development of the RTC

Section 4928.39(D), Revised Code states, in part:

> Further, the commission's order under this section shall identify separately regulatory assets of the utility that are a part of the total allowable transition costs determined under this section and separately identify that portion of a transitions charge determined under Section 4928.40 of the Revised Code that is allocable to those assets,...

This section, in combination with Section 4928.01(A)(26), Revised Code, and the requirement that "...the total of all unbundled components in the rate unbundling plan are capped and shall equal during the market development period... the total of all rates and charges in effect under the applicable bundled schedule of the electric utility...including the transition charge determined under section 4928.40 of the Revised Code..." [Section 4928.34(A)(6), Revised Code] together make it clear to the Staff that the determination of the regulatory transition charge is to be based on regulatory asset balances as they appeared in the Applicant's most recent rate proceeding, including the balances of certain other assets that were identified as included in regulatory assets under this statute.

In DP&L's case, the Staff believes that this requires that the RTC be determined based upon the recovery of regulatory assets as identified in Case No. 91-414-EL-AIR.

In light of the foregoing discussion, the Staff takes exception to one of the Applicant's proposals and recommends that the Commission take the following action in determining appropriate RTC rates. It should be noted that the Staff's exception in this section is only with regard to the determination of appropriate RTC values. Unless noted elsewhere, the Staff does not take exception with regard to this item in the determination of Transition Costs.

F-14. Killen Post-In-Service Carrying Costs – The Staff takes exception to the company's calculations with regard to the revenue requirement associated with Killen Post-In-Service Carrying Costs, as it appears that this calculation reflects a total company, rather than jurisdictional basis.

AAM Requests

Based on the Staff's review of the DP&L filing, the Staff is of the opinion that DP&L's filing includes the following requests for accounting treatment. The Staff's position on each of these requests is included within each discussion.

F-15. Energy Imbalance System - The Staff is of the opinion that these deferrals are appropriate. However, these deferrals should be subject to a showing of material financial impact.

F-16. Customer Billing System Enhancement - The Staff is of the opinion that these deferrals are appropriate. However, these deferrals should be subject to a showing of material financial impact.

F-17. Electric Restructuring Consumer Education - The Staff is of the opinion that these deferrals are appropriate. However, these deferrals should be subject to a showing of material financial impact.

Part G – Transmission Plan

Introduction

Section 4928.12, Revised Code requires each electric utility owning transmission facilities to be a member of and transfer control of the transmission facilities it owns or controls within Ohio to a qualifying transmission entity. To be a qualifying independent transmission entity (ITE) it must satisfy the nine specifications listed in division (B) of Section 4928.12, Revised Code and the specifications as clarified in paragraph (B) of 4901:1-20-17, Ohio Administrative Code.

Summary Description of the Applicant's Transmission Plan

Dayton Power and Light has not committed to joining an Independent Transmission Entity. In the Transition Plan filing the company directs the reader to specific sections of the Midwest ISO filing and the Alliance RTO filing at FERC which the Company feels complies with the ITE rules as found in 4901:1-20-17, Ohio Administrative Code. The company is currently considering the Midwest ISO or the Alliance RTO as a means for complying with the ITE requirements.

Staff's Exceptions and Recommendations

G-1. **Commitment to an ITE –** Dayton Power and Light has not committed to an ITE but claims that it will join a qualifying ITE by January 1, 2001. The Commission cannot approve this portion of Dayton Power and Light's transition plan without the company identifying an ITE and providing evidence that it satisfies the requirements as found in both Section 4928.12, Revised Code and paragraph (B) of 4901:1-20-17, Ohio Administrative Code.

G-2. **Plan to minimize pancaked transmission rates -** Rule 4901:1-20-17, paragraph (B)(3) requires that a qualifying transmission entity implement policies and procedures to minimize pancaked transmission rates within Ohio. The rule requires that electric utilities under the Commission's jurisdiction should either: (1) all be in one transmission entity that minimizes pancaked rates to all retail customers within Ohio; or (2) provide appropriate reciprocity requirements between Ohio jurisdictional companies that minimizes pancaking of rates within the State; or (3) propose another means to effectuate the policy objectives that call for a minimization of pancaking of rates within Ohio.

Dayton Power and Light claims that it will comply with Rule 4901:1-20-17, paragraph (B)(3) but does not describe how compliance will be accomplished nor is there a report of any actions taken in this regard. Staff views the Rule 4901:1-20-17, paragraph (B)(3) as an important aspect of the requirements to comply with Section 4928.12, Revised Code. The Commission cannot approve Dayton Power and Light's transition plan until the company complies with this section in a manner satisfactory to the Commission.

Part H - Shopping Incentive

Introduction

Chapter 4928, Revised Code, sets forth the statutory requirements for a shopping incentive first in Section 4928.40, (A), second paragraph, and again in Section 4928.37, (A)(1)(b). Section 4928.40, Revised Code, describes several factors that must be considered by the Commission in prescribing the expiration date of a utility company's market development period and the transition charge for each customer class and rate schedule of the utility, and provides that one such factor shall be, "….such shopping incentives by customer class as are considered necessary to induce, at the minimum, a twenty percent load switching rate by customer class halfway through the utility's market development period but not later than December 31, 2003. "

Chapter 4928, Revised Code, goes on to limit the potential amount of the shopping incentive by mandating that, "in no case shall the Commission establish a shopping incentive in an amount exceeding the unbundled component for retail electric generation service set in the utility's approved transition plan under section 4928.33 of the Revised Code, and in no case shall the Commission establish a transition charge in an amount less than zero." In Section 4928.40 (B)(2), Revised Code, satisfactory shopping incentive results (a 20% shifting of load from the incumbent in each customer class, as noted above) are referred to as one cause for the Commission to consider ending the market development period.

The shopping incentive is further elaborated in Section 4928.37, (A)(1)(b), Revised Code, where notice is given that, "additionally, as reflected in section 4928.40 of the Revised Code, the transition charges shall be structured to provide shopping incentives to customers sufficient to encourage the development of effective competition in the supply of retail electric generation service."

This section of the staff report is focused on evaluating the Applicant's proposed plans for migrating 20% of the customer load from each customer class away from the incumbent to other suppliers of electricity per the mandates of Chapter 4928, Revised Code. The Staff believes that "shopping incentive," as described in Chapter 4928, Revised Code, (see above) can be conceptualized as consisting of two components, a retail market price component and an incentive component. As part of this section, Staff will review the Applicant's proposed transition plan filing in the context of both the establishment of a just and reasonable retail market price and the development of incentives to induce 20% of the load in each customer class to switch suppliers.

The Shopping Incentive Plan Proposed by the Applicant

The Applicant describes its proposed shopping incentive plan in "Report on Shopping Incentives, Transition Plan - Part H," a 55-page document prepared by National Economic Research Associates (NERA) and authored by Dr. Hethie Parmesano, et. al. The Applicant redefines shopping incentive as "shopping credit," reasoning that in the context of Chapter 4928 Revised Code, "the term 'shopping incentive' actually refers to the total 'shopping credit' that the customer receives when switching retailers." (Report at page 4)

Part A - Market Price

The Applicant proposes that the "shopping credit", an amount deducted from the Applicant's bill to a customer that switches suppliers, should be DP&L's avoided cost. This is calculated by the Applicant as the "market price," which is determined using the market price for generation, without retailing costs but including losses and avoided administrative costs, for each customer class. The Applicant offers specific "shopping credits" for several rate schedules on a quarterly basis for the years 2001 through 2005. (Report, Table 1, page 14)

DP&L takes as its "starting point for the proposed shopping credits….a forecast for 2001-2005 of hourly spot prices at each load bus within DP&L's service territory…(and) used a weighted average of the hourly prices at these busses, with hourly loads at each bus (market node) as the weights. The next step was to take estimated load curves for each rate schedule and compute load-weighted average market prices for each rate schedule by season within year. During this step……the wholesale prices were adjusted for estimated losses between the market nodes and customers' meters. Finally, (the Applicant) made a small adjustment for avoided cash working capital requirements when DP&L sells less energy to a wholesale customer instead of a retail customers. Since wholesale payments are likely to be received sooner than payments for purchases by retail customers, DP&L avoids financing some cash working capital when a customer chooses an alternative supplier." (Report at page12)

DP&L states that, "(t)he avoided cash working capital component was developed by comparing the lag between the end of the billing cycle and receipt of payment for retail and wholesale transactions. Because the market rules for settlement have not yet been developed in Ohio, (the Applicant) used the wholesale lag in California Power Exchange (Cal PX) as a proxy. DP&L's retail payment lag, as shown in its most recent lead-lag study is 28.5 days, while the Cal PX lag is 17 days. The difference, 11.5 days, was divided by 365 days and multiplied by the revenue requirement for cash working capital from DP&L's most recent avoided cost filing (14.89 percent) to produce a working capital adjustment factor of 0.47 percent." (Report at page 12)

The Applicant's "shopping credits," as shown in Table 1 of the NERA Report, are presented on a seasonal (quarterly) basis. DP&L states that, "(t)he summer shopping credits on Table 1 are higher than the residual generation components. However, the reverse is true in the other seasons so that, across the year, DP&L's proposed seasonal shopping credits do not exceed the residual generation component computed when generation costs in bundled rates are reduced by the customer transition charges (CTC) and regulatory transition charges (RTC)." (Report at page 12-13) The Applicant notes that "the shopping credits that will be computed on the bills of street lighting and private outdoor lighting customers are capped by the residual generation component." (Report at page 13 [footnote])

The Applicant believes that "(t)here is a high likelihood that each of the four major customer groups in DP&L's service territory (residential, commercial, industrial and public authorities) will achieve the 20 percent legislative targets for participation in retail access by the end of 2003 with shopping credits set at DP&L's proposed levels." (Report at page 54) This belief is supported by a review of switching behaviors in California, Pennsylvania and Massachusetts which look at factors such as history of switching rates, price as a factor in switching rates, shopping credit design, aggregation, education programs and customers' prior experience. The Applicant did not conduct DP&L service territory-specific customer switching behavior research in support of the premise that its proposed "shopping credits" would be sufficient to cause 20% of the load in each customer class to switch suppliers by the mid-point of the market development period.

DP&L proposes a four-step plan to adjust "shopping credits" if the actual switching rates differ from its initial projections, (Industrial - Table 8, page 44, Commercial - Table 11, page 47, Public Authority - Table 14, page 50, Residential - Table 16, page 53 of Report) This process begins with the Applicant performing a comprehensive study, in each of the first two market development years, of the pattern of switching rates, surveys of customers who switched and those who have not switched, surveys of trade organizations that might be aggregators and a review of the results of the six-month evaluation of consumer education programs. Step two would be to identify measures (other than higher "shopping credits") to eliminate barriers to participation and to implement those measures in the first quarter of years two and three. Measures might include enhanced customer education programs or modifications in procedures to eliminate barriers to switching. The third step would be to estimate the effectiveness of measures implemented in step two. DP&L proposes the final step to be adding an incentive to the "shopping credits," "if it appears that after the second year… the 20-percent participation targets by class are unlikely to be met by the end of the third year." (Report at page 17) The Applicant states that it would conduct a study and develop a "discrete choice model" at the end of the second year and would "implement shopping incentives based on the results of the study at the end of the first quarter of the third year." (Report at page 18)

Part B - Incentive

DP&L does not provide shopping incentives as part of its initial "shopping credit" proposal, but instead suggests that shopping incentives might be implemented "at the end of the first quarter of the third year" (Report at page 18) if necessary to attain the 20% load in each customer class mandated by Chapter 4928, Revised Code. The Applicant states that, "the setting of extra shopping incentives should be approached cautiously," since, "(e)xtra shopping incentives given to achieve arbitrary levels of participation can lead to uneconomic bypass and under-recovery of stranded costs." (Report at page 4)

Staff's Exceptions and Recommendations

H-1. The Staff takes exception to the Applicant's calculation of "shopping credits" without adding retailing costs. By so doing, the Applicant has effectively set market wholesale prices as the "price to shop" for customers in its service territory and created a distinct disincentive for competitive providers to enter the market. It would be unreasonable to expect marketers to offer a competitive retail product measured against wholesale market prices. DP&L's proposed method for setting "shopping credits" would effectively eliminate any potential for competition in its service territory.

H-2. The Staff has concerns with the Applicant's proposed "shopping credits" adjusted on a seasonal basis. (see Report, Table 1, page 14) A "shopping credit" adjusted quarterly brings with it the potential for violating Chapter 4928, Revised Code, mandated rate caps and shopping incentive limit during the Summer months. In addition, "shopping credits" that might change during the term of a switching customer's contract would cause confusion in evaluating potential savings and act as a disincentive and a potential barrier to customer shopping.

H-3. The Staff takes exception to the fact that the Applicant has not proposed shopping incentives as an initial part of its transition plan filing. The Applicant has, instead, proposed "shopping credits" for each customer class consisting of DP&L's avoided cost, which would be the "market price," calculated by using a market price for generation, without retailing costs, but including losses and avoided administrative costs. The Applicant states that, "extra shopping incentives given to achieve arbitrary levels of participation can lead to uneconomic bypass and under-recovery of stranded costs." (Report at page 4) Staff understands Section 4928.40, Revised Code, to have set a specific, level of participation at 20% of load in each customer class by the midpoint of the market development period. It is Staff's opinion that Section 4928.40, Revised Code, establishes that particular level of customer switching and time frame to both encourage customers to choose alternative providers and to encourage the development of effective competition in the supply of retail electric generation service in the Applicant's service territory.

The Applicant's argument that its "proposed approach is better than allowing potential competitors to try to tilt the playing field in their favor by proposing more aggressive shopping credits" does not comport with Chapter 4928.40, Revised Code. The legislature specified that an incentive be established such that 20% of the customer load of each customer class switch from the incumbent. It is implicit in the implementation of this incentive that the motivation to switch takes precedence over market signals and forces during the market development period. The legislature has spoken on the need to stimulate the marketplace by providing for an incentive. The economic efficiency arguments miss the point. During the market development period, developing the market is the primary goal.

H-4. Staff does not agree with the Applicant's plans to wait until "the end of the first quarter of the third year" (Report at page 18) to implement shopping incentives. DP&L acknowledges that, "participation rates increase gradually and vary by customer category." (Report at page 23) Customer switching rates in other states, as reported by the Applicant, reveal that any waiting to implement a shopping incentive would seriously handicap the potential for customer switching and that to wait until the third year would essentially guarantee that the 20% target would not be reached for residential and small commercial customers.

H-5. The Staff is not convinced that the Applicant has demonstrated that its proposal will result in 20% of the load of all customer classes switching suppliers by the midpoint of the market development period. DP&L's projections rely virtually exclusively on switching data from other states. Those data do not provide clear evidence of the potential for requisite levels of switching to be attained. The Applicant has not provided service territory-specific customer switching behavior data in any of the customer classes to support its projections of switching frequency. In addition, the Applicant's process and methodology for projecting annual levels of switching across customer classes appears to be highly speculative and subjective and does not allow the Staff to conclude that projected annual switching levels will be attained with any degree of certainty.

H-6. The Staff recommends that the Applicant identify and implement an adequate shopping incentive from the beginning of the market development period in order to achieve a 20% switching rate for each customer class. The Applicant's proposed transition plan fails to demonstrate that its "shopping credit" and four-step adjustment plan will accomplish the customer switching goals that are clearly defined by Chapter 4928, Revised Code. Instead of conducting a study to develop a discrete choice model at the end of the second year of the market development period, DP&L should conduct the study and create the discrete choice model immediately, to enable identification and implementation of shopping incentives at the onset of the market development period.

Part I - Potential Structural Impediments to Retail Competition

Introduction

In this section of the report, Staff addresses issues that are structural in nature and may impede customer choice or the development of effective competition in the provision of electric generation services in Ohio. The exceptions and Staff recommendations discussed here are intended to complement Staff recommendations found elsewhere in this report.

I – 1. Transmission Requirements:

Dayton Power and Light's proposed plan for transmission requirements is described in direct testimony by Applicant witness Hertzel Shamash, who states that the Applicant's independent transmission plan includes

> the goals of encouraging market access for cost-effective and supply-and-demand side retail electric service, and encouraging cost-effective and efficient access to information regarding the operation of DP&L's transmission system in order to promote effective customer choice of retail electric service. *Testimony* at 3.

There is a finite amount of transmission capacity in Ohio, which is more scarce during peak periods**.** Staff notes that 2,484 MW of the Applicant's 3,107 MW of generating capability (summer ratings) is represented by generating units external to the Dayton service territory that Dayton owns in common with neighboring utility companies. During day-to-day operations, the Applicant uses the tie lines to neighboring utilities to import its share of the energy produced by these commonly-owned generating units. The Applicant reports that it can accommodate these imports on behalf of its native load customers as well as contracted external purchases without exceeding the normal ratings of any transmission facility. *DP&L Open Access Transmission Tariff* (DP&L OATT), Original Sheets No. 84, 88-89.

Staff's Exception and Recommendation

Staff takes exception to the failure of the Applicant's proposed plan to address how transmission capacity calculated for the Applicant's share of external energy sources on behalf of retail standard offer service customers will be released for access by the customers or by certified suppliers to use on behalf of customers who migrate away from the standard offer. When the Applicant's obligation to serve energy to native load customers is converted to implicit contractual arrangements between those customers and certified suppliers, the capability to deliver that service must "follow the customer." Not to do so discriminates against the customers who switch to certified suppliers and denies them the comparable access to transmission capacity to satisfy their electricity requirements from a certified supplier promised by Substitute Amended Senate Bill 3:

> [b]eginning on the starting date of competitive retail electric service and notwithstanding any other provision of law, each consumer in this state and the suppliers to a consumer shall have comparable and nondiscriminatory access to noncompetitive retail electric services of an electric utility in this state within its certified territory for the purpose of satisfying the customer's electricity requirements… Section 4928.03 Revised Code

Staff notes that network integration service allows the network customer to serve its network load "in a manner comparable to that in which Dayton utilizes its Transmission System to serve its Native Load Customers." (DP&L OATT Original Sheet No. 38).

A potential problem may exist, however, when retail customers' requirements for transmission facilities change due to changes in sources of supply. Under competitive retail electric service, network delivery from the Applicant's generation to the customer's load may be replaced by network delivery from alternative resources outside the network to the customers' load. For that reason, Staff recommends the activation of the Network Operating Committee described in Section 34.3 of the DP&L OATT or, alternatively, an Ohio commission-sponsored collaborative approach, to negotiate procedural solutions to accommodating changes in sources of supply for the retail market in Ohio.[7]

The Network Operating Committee or the alternative Ohio-commission-sponsored collaborative should be given the opportunity to negotiate fair and nondiscriminatory procedural "rules of the road" for releasing network capacity to accommodate the Applicant's standard offer customers in Ohio who migrate to certified suppliers. Pricing of such released capacity should conform to FERC rules and the standards for sale, assignment or transfer of transmission service suggested by Section 22.1 of the DP&L OATT.

I-2. Meeting the Requirements of Governmental Aggregators which Elect Automatic Enrollment

In its Shopping Incentive Plan, the Applicant notes one of the greatest differences between the Ohio retail access rules and the rules of other states is the aggregation "opt-out" clause.[8] By allowing customers to be automatically enrolled in governmental aggregation programs approved by the voters and requiring customers to take action to

[7] The stated purpose of the Network Operating Committee is to coordinate operating criteria for the Parties respective responsibilities under the Network Operating Agreement. The DP&L OATT states that each Network Customer is entitled to have at least one representative on the Applicant's Network Operating Committee, which is to meet from time to time as need requires. DP&L OATT Original Sheet No. 52.

[8] In accordance with Section 4928.20 (D), Revised Code, the electric loads of residents and businesses located in municipal corporations, townships, or unincorporated area of a counties where electors approve passage of a ballot issue for automatic enrollment in a governmental aggregation program, are combined for the purpose of being served by competitive electric retail service until a person so enrolled affirmatively elects by a stated procedure not to remain so enrolled.

be excluded, the Applicant predicts, "the Ohio rules will probably result in more aggregation than has occurred in other states, particularly for the residential and small commercial classes, provided aggregation is economically attractive in Ohio… ." *Shopping Incentive Plan* at 34-35.

Dayton Power and Light's proposed plan for governmental aggregation is stated in Part C of its Operational Plan, in which the Applicant states,

> …DP&L will provide information to the government entities on the types of aggregation service (opt-in vs. opt-out) listed in Revised Code Section 4928.20, the procedural steps for the aggregation service, the customer notification requirements, and potential risks and benefits. DP&L will also provide information and expertise to the governments through various resources including the account management group, community relations programs, workshops, and speakers bureau programs. *Operational Support Plan* at 6.

Staff's Exceptions and Recommendations

Elements of the Applicant's Operational Support Plan are being discussed in the Operational Support Workgroups. Staff defers its recommendation on this issue pending the outcome of the workgroups and reserves the right to offer comments and testimony on this issue in the hearing.