Staff Report

of

Exceptions and Recommendations

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of Their Transition Plans And for Authorization to Collect Transition Revenues.	)	Case No. 99-1212-EL-ETP
In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Tariff Approval.	)	Case No. 99-1213-EL-ATA
In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Certain Accounting Authority.	)	Case No. 99-1214-EL-AAM

The Public Utilities Commission of Ohio

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of Their Transition Plans And for Authorization to Collect Transition Revenues.	))))))))	Case No. 99-1212-EL-ETP
In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Tariff Approval.	))))))	Case No. 99-1213-EL-ATA
In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Certain Accounting Authority.	))))))	Case No. 99-1214-EL-AAM

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, and J. Edward Hess, Chief of the Electricity 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 will promptly set this matter for public hearing. Written notice of the time, place, and date of such hearing will be served upon all parties to the proceeding.

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,

Christine M. T. Pirik
Chief of Staff

Deborah Gnann
Director
Consumers Service Department

Douglas R. Maag
Deputy Director
Utilities Department

J. Edward Hess
Chief, Electricity Division
Utilities Department

Background

The Cleveland Electric Illuminating Company (CEI) was incorporated in Ohio on September 24, 1892, as The Cleveland General Electric Company. The present name was adopted on July 21, 1894. The Toledo Edison Company (Toledo Edison) was incorporated under the laws of the State of Ohio on July 1, 1901, as Toledo Railway and Light Company and the present name was adopted in 1921. The Ohio Edison Company (Ohio Edison) was incorporated as an Ohio corporation on July 5, 1930.

On April 29, 1986, an agreement was approved to merge CEI with the Toledo Edison, forming the Centerior Energy Corporation. On November 8, 1997, Centerior Energy and Ohio Edison merged under a new holding company called FirstEnergy Corporation (FirstEnergy). FirstEnergy has approximately 2.2 million customers and covers 13,200-square-mile service area in central and northern Ohio and western Pennsylvania. It has approximately $5 billion in annual revenues, more than $18 billion in assets, nearly 12,000 megawatts of generating capacity, 7,500 miles of transmission lines, and 35 interconnections with 8 electric systems.

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 and a Second Entry on Rehearing on January 27, 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 those rules is listed at the PUCO's Electric Restructuring Web site (http://www.puc.ohio.gov/CONSUMER/restructuring/proposed_rules.html).

On October 4 and October 5, 1999, FirstEnergy filed a transition plan for each of its electric utility subsidiaries, Ohio Edison, CEI, and Toledo Edison (collectively the Companies). By Entry dated November 4, the PUCO rejected the applications and directed FirstEnergy to re-file the applications consistent with the PUCO's rules on Transition Plan filings. On December 22, 1999, FirstEnergy re-filed its application. In addition to its application, FirstEnergy 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 education plan, an application for the authority to collect transition revenues, an explanation of FirstEnergy'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. FirstEnergy held a technical conference on January 4, 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 5, 2000, several parties filed preliminary objections to the plans. The Commission has scheduled a second technical conference for February 22, 2000.

Scope of the Staff's Investigation

The scope of the Staff's investigation was designed to determine if the Transition Plan filed by FirstEnergy meets the applicable requirements of Chapter 4928, Revised Code. The scope of the investigation was also designed to determine compliance with 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 originally filed by FirstEnergy and all of the revisions and updates that were subsequently filed. The Staff 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 scope and detailed results of the consultant's investigation are included in the consultant's 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's Exceptions and Recommendations to the Applicant's Transition Plan

Part A – The Applicant's Unbundling Proposal

Introduction

Section 4928.31(A)(1), Revised Code mandate 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. 95-300-EL-AIR for CEI; Case No. 95-299-EL-AIR for Toledo Edison, and Case No. 89-1001-EL-AIR for Ohio Edison. The Electric Fuel Component Rate (EFC) for CEI, Toledo Edison, and Ohio Edison were approved in Case Nos. 99-108-EL-EFC, 99-107-EL-EFC, and 99-104-EL-EFC, respectively. The Percentage of Income Payment Plan rates (PIPP) for Toledo Edison, CEI, and Ohio Edison were approved in Case Nos. 99-299-EL-AIR, 99-300-EL-AIR, and 94-525-EL-PIP, respectively.

The Applicant has entered into new contracts and has added new tariff schedules since the last rate cases and such contracts and schedules were unbundled based on the rates in effect on October 5, 1999. Certain base rates for various customer classes were reduced according to the Commission approved rate plans in Case No. 96-1211-EL-UNC for CEI and Toledo Edison, and Case No. 95-830-EL-UNC for Ohio Edison. However, the Applicant unbundled the rates for all contracts and tariff schedules that were in effect on October 5, 1999.

The current bundled rates of the Applicant were unbundled into the following components: Distribution Charge, Transmission Charge, Ancillary Services Charge, Regulatory Transition Charge, Generation Transition Charge, Universal Service Charge, Energy Efficiency Charge and 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 Opinion and Order signed by the Commission in that case. Based on that COSS, the Applicant developed an unbundled COSS, which included adjustments as required by Chapter 4928, Revised Code, as well as additional adjustments resulting from the refunctionalization of certain accounts in its COSS.

Following the application of functionalizing into generation, transmission and distribution, the Applicant unbundled rates into the components previously mentioned. As required by Chapter 4928, Revised Code, the Applicant developed its transmission rates based on its FERC OATT as filed with the FERC. The distribution rates were then based on the total of the transmission and distribution revenue requirement as determined by the COSS minus the transmission revenue requirement as contained in the Applicant's FERC OATT.

The ancillary charges were unbundled from either generation or transmission depending on where they were contained in the COSS. From generation the companies 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 Generation Transition Charge revenue requirement will be discussed in a later section 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 Charge is based on the portion of the PIPP rider that is related only to the on-going costs of the program. The remaining 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 administration costs associated with program.

The Applicant has included a place-holder in its tariffs for the Energy Efficiency Fund Charge; however, at this time the charge is not known. The Applicant will include 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. Further adjustments were made to the generation component, including the five-percent residential reduction, as mandated by Chapter 4928, Revised Code.

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 Rule 4901:1-20-03, Appendix A, Section (F), followed by a discussion of those exceptions that may not fall under the UNB Schedule categories.

For each of the following sections the discussion will be divided between those exceptions that are common to CEI, Toledo Edison, and Ohio Edison, followed by a discussion of those exceptions that are unique to each of the individual companies.

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.

Exceptions that are common to CEI, Toledo Edison, and Ohio Edison

Standard Rules and Regulations

A-1. In Section (II)(A), Applications and Contracts, the Applicant states that for same day service the Applicant will charge the customer a reconnection charge as provided in the Miscellaneous Charge section of the tariffs. The Staff takes exception to the proposed change in procedures for new customers applying for service. In addition, the language fails to identify what specific charge is applicable. The Staff recommends that the Applicant file support for the proposed charge as well as sufficient rationale for including this provision in its tariffs.

A-2. In Section (II)(D) of Applications and Contracts, the Applicant has provided uniform language for all three companies from language currently used in Ohio Edison's tariffs. However, the original Ohio Edison language states, "Customers now served who seek to increase their present capacity requirements to more than 1,000 kilovolt-amperes (kVA) and new customers who seek to purchase capacities of more than 1,000 kVA". The proposed language states, "Existing customers who seek to substantially increase their existing capacity requirements and new customers who seek to purchase substantial capacity from the Company". The proposed language fails to clarify substantial. The Staff recommends that the Applicant include language to clarify the meaning of "substantial".

A-3. In Section (VIII) under Temporary Facilities, Ohio Edison's existing language states, "When electric service is required temporarily for any purpose, the applicant shall deposit with the Company the total estimated cost of construction, plus the total estimated cost of removal, minus the estimated salvage value of all equipment and materials. The amount of the deposit shall be adjusted by a refund or an additional payment when the cost of construction and removal, less the salvage value is determined." The Applicant proposes using the existing Ohio Edison language for all three First Energy companies in addition to new language as follows: "Temporary service is any separate installation that the Company does not expect to be permanent or regarding which a substantial risk exists that the Company's facilities will be used and useful for a period substantially shorter than their normal expected life, or in which the customer or consumer has no substantial permanent investment." The proposed language fails to clarify the word "substantial". The Staff recommends that the Applicant include language to clarify the meaning of "substantial".

A-4. In Section (IX) the proposed language states the conditions for providing electric service in parallel with a customer's generating facilities. It is unclear, however, whether these provisions affect a customer's eligibility for Net Metering service.

Staff recommends this section be so clarified and be consistent with the requirements of Section 4928.67, Revised Code as well as Staff's proposed ESSS Rule 28 and Interconnection Rules 03 and 04. Staff also recommends this section include a reference to the Applicant's proposed Net Metering Rider.

A-5. In Section (X)(A) of Meters, Transformers and Special Facilities, the proposed language fails to state whether the customer pays the full cost or incremental cost of meter installation. The Staff recommends that the Applicant include language stating that customers will pay the incremental cost of meter installations.

A-6. In Section (X)(A) of Meters, Transformers and Special Facilities, the Staff takes exception to the Applicant's proposal to require all metering equipment from an AGS to be owned, installed and maintained by the Applicant. Staff recommends that additional metering equipment that could be supplied by an AGS in conjunction with the Applicant-owned billing meters should be allowed.

A-7. In Section (XIII) the proposed language states "the list of certified suppliers will be maintained by the Commission." This section is not clear, however, on whether the Applicant will maintain a list of such suppliers it has approved for operation within its own service territory. Staff recommends this tariff section commit the Applicant to maintain such a list, provide it to all its customers at the onset of competition, to all of its new customers, to all customers returning to its standard offer, and to all of its other customers upon request.

A-8. In Section (XIV) the proposed language requires aggregators, municipal aggregators, power marketers and power brokers to provide the Applicant at least one-month's written notice before one of their customers could return to the Applicant's standard offer service. This prior-notice requirement, however, would not apply to customers who are served individually by a generation supplier. 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. Section (XIV) imposes a twelve-month minimum term for customers returning to standard offer service. Staff recommends that these customers be allowed at least thirty days, after their previous CRES services is terminated, to select another CRES provider before such twelve-month term becomes effective. This would ensure that such customers have an adequate opportunity to participate in a competitive electricity market.

A-10. In Section (XIV)(A) the Applicant fails to adequately specify what is meant by "sufficient notice". The Staff issued Data Request No. 34. The Staff has yet to receive a response from the Applicant.

Partial Service Schedule

A-11. Staff recommends that the rates of the Partial Service schedules be unbundled to allow customer-generators who operate in parallel with the Applicant's system to obtain partial service generation from a competitive supplier, or the Applicant should provide sufficient rationale as to why the service is available only to customer-owned non-synchronous generation within thirty days from the time the Staff report is issued.

A-12. For its Partial Service schedules, the Applicant failed to provide Schedules UNB 3.1 – UNB-8. The Staff recommends that these schedules be provided or the Applicant should provide sufficient rational as to why they were not provided within thirty days from the time the Staff report is issued.

Line Extensions

A-13. The Applicant has failed to justify its proposed revisions to its line extension policy. The Applicant should provide such justification within thirty days of the issuance of this Staff Report.

Resale

A-14. The Applicant has failed to justify its failure to remove its restrictions on Resale in its filed tariffs. The Applicant should provide such justification within thirty days of the issuance of this Staff Report.

Net Energy Metering Rider

A-15. The Applicant's proposed "Net Energy Metering Rider" (Sheet No. 94) would provide certain qualifying customer-generators credit for excess electricity they generate and feed back into the distribution system. Accordingly, the Applicant would credit the generation portion of the bill, at the same rate charged, for the amount of customer-generated electricity fed to the system, while billing the customer-generator the gross metered distribution, transmission, and ancillary charges. Staff believes it is appropriate to use these two different billing mechanisms, since net metering only applies to generation charges. The Rider goes a step further, however, and again imposes charges for distribution, transmission, and ancillary charges relating to customer-generated electricity fed back into the Company's distribution system. Staff believes such an additional charge causes an inappropriate double billing, because this electricity is used by other customers, who pay the same charges. Staff recommends the deletion of this second round of charges.

A-16. Another issue related to Net Metering involves the type of meter to be used. Because net metering requires generation service to be net metered while other components (e.g. transmission and distribution service) must be metered in the usual way, Staff sees no alternative to using meter(s) that register the flow of electricity separately in each direction. Having said this, Staff believes electric distribution companies should assist the customer in obtaining the least costly method for obtaining these two separate measurements. A customer who currently uses a simple mechanical meter should not be required to have a demand meter or an interval meter simply due to the installation of solar panels with a net metering arrangement. And if the least expensive metering option for such a customer is for the utility to install another simple mechanical meter to measure electricity in the other direction, the customer should be allowed such an option. Finally, Staff believes the Applicant should submit cost-based tariff charges for any extra metering needed for a net-metering arrangement. Staff recommends the Applicant's Net Metering Rider be modified to reflect these positions.

Electric Generation Supplier Coordination Tariff

A-17. At 3.1 (e), the Applicant requires an electric generation supplier (EGS) seeking to obtain Coordination Service from the Applicant to file "a copy of the EGS's conditional certification issued by the Commission to provide Competitive Retail Electric Services to the Company's retail customers." Also, Section 3.9 would start coordination services after the Commission issues the supplier a "final certification following the Applicant's approval of the [supplier's] registration for Coordination Services." Both these provisions contemplate a two-step – conditional and final – certification process for an EGS at the Commission. The proposed certification rules currently before the Commission (Case No. 99-1609-EL-ORD) do not provide for such a two-step process. Moreover, the staff believes that Section 4928.08, Revised Code regarding Commission certification of competitive retail service providers, does not permit a two-step certification process at the Commission. The Staff recommends that Section 3.1(e) be deleted.

A-18. At 3.1 (f), the Applicant requires an EGS seeking to obtain Coordination Service from the Applicant to file "a copy of the EGS's certification application submitted to the Commission to apply for its certificate." 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-19. Finally, Section 3.1 is unclear as to whether the supplier or the customer has the option to receive one or two bills. According to Staff's proposed CRES Rule 14 (A), this option should be the supplier's. Staff recommends this tariff section be so clarified to give the supplier this option (consistent with the Commission's final ruling on the CRES rules).

A-20. Section 3.2 would allow the Applicant thirty days to inform the supplier of any deficiencies in its application. Some parties are discussing this issue (whether a thirty-day time period is appropriate) 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-21. According to Section 4.13, the Applicant would release customer account numbers to suppliers. Such a practice would violate proposed ESSS Rule 22 (D)(1), which prohibits such release. In order to prevent slamming, only the customers should be allowed to release their account numbers. Staff, therefore, recommends this section be modified to omit the release of customer account numbers (consistent with the Commission's final ruling on the proposed ESSS and Market Monitoring rules).

A-22. Section 4.13 provides no information about whether and how individual customer monthly usage data would be made available to other electric light companies on a nondiscriminatory basis (unless the customer objects), as required by Section 4928.10 (G), Revised Code and as intended by Staff's proposed ESSS Rule 22 (D)(5). 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-23. Sections 5.1 and 5.3 would require a customer's signature indicating the customer's choice of supplier and authorizing the Applicant to act on the customer's behalf. To the extent these sections apply to telephone and internet enrollment, such a requirement is contrary to Staff's proposed CRES Rule 6, which requires the customer's signature only for direct enrollment. Staff recommends both these sections be modified to be consistent with CRES Rule 6 (consistent with the Commission's final ruling on the CRES rules).

A-24. Section 5.3 would allow the Applicant three business days to send suppliers validations of electronic files requesting their enrollment of specific customers. Some parties are discussing this issue (whether three days is appropriate) 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-25. Section 5.3 would also allow the Applicant five business days to mail customers notification that a supplier has requested their enrollment. Some parties are discussing this issue (whether five days is appropriate) 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-26. Sections 5.3, 10.5, and 14.3 would require customer enrollments, supplier changes, and service terminations to be effective on the next regular meter-read date. These provisions would allow for an estimated (as a substitute for an actual) meter reading in these situations. Some parties are discussing the estimated meter-reading 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-27. Section 5.3 is unclear about whether customers would have to re-enroll, (or default to the EDU's standard-offer service), whenever they move from one location to another within the EDU'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-28. Sections 10.1 through 10.3 would require certain customers (who have no interval meter but have billing demand of 100 kW or more) desiring a CRES provider to have an interval meter installed. The supplier would have to pay the Applicant for the cost of such meter and its installation. Such meter would then become the property of the Applicant. 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-29. Section 11.1 restricts the disclosure of information the Applicant provides to CRES providers. Staff recommends this provision be clarified to ensure that the Commission would have access to any such information.

A-30. Section 12.1 would prohibit customers from receiving budget billing if they elect to receive service from 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-31. Section 12.1 also prohibits a supplier from physically disconnecting electric service for non-payment of supplier charges. This provision does not, however, clarify whether the supplier could request the Applicant to disconnect service for such nonpayment. Staff recommends that this section be clarified, consistent with its proposed CRES Rule 2 (B), to prohibit the Applicant from disconnecting a customer for nonpayment of CRES provider charges.

A-32. Sections 12.2 and 16.1 appear to conflict with each other concerning the number of days required for a CRES provider's non-payment of Applicant charges to constitute a breach of contract. Section 12.2 says a thirty-day nonpayment constitutes a breach, while Section 16.1 has a five-day non-payment period. 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-33. Section 14.2 would require suppliers to provide thirty-days notice to discontinue service (i.e. terminate the customer contract). Some parties are discussing this issue (whether 30 days is appropriate) 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-34. The Applicant lists supplier charges on Pages 43 and 44. Staff recommends this listing include a charge for billing services the Applicant would provide for the supplier, and that such charge be based on the incremental cost of such services.

Experimental Day Ahead Real Time Pricing

A-35. In the Applicability Section, the Applicant is proposing language as follows: "At the Company's discretion, the participation limits may be increased up to 100% from the above stated levels." The language is unclear as to which limits it is referring to. The Staff recommends that the language be clarified to indicate which limits are being referred to.

Other Schedules

A-36. In several schedules the Applicant added language requiring customers to be full service customers in order to be served under the tariff. It is not clear why it is necessary to be a full service customer to receive certain services that are provided by the Applicant. The Applicant fails to adequately explain why certain tariffs specify that a customer must be a full-service customer to qualify for that tariff. Staff issued Data Request No. 34 requesting such explanation.

A-37. The Applicant failed to provide specific information for each schedule that was deleted as to whether the schedule was deleted as a result of legislation or if there are currently no customers being served. Staff recommends that the Applicant provide more detailed rationale for the elimination of each schedule.

Exceptions specific to CEI

Private Property Line Extension Schedule – Sheet No. 49

A-38. The Applicant failed to specify what the estimated connection charge would consist of. Staff issued Data Request No. 55 to request this information.

Exceptions specific to Toledo Edison

Optional Electrically Heated Apartment Rate R-09a - Sheet No. 19

A-39. In the Terms and Conditions Section, the Applicant fails to note textual changes. The current language reads "SEER of 10" and the proposed reads "SEER of 9." The Staff recommends that the Applicant explain the difference.

Small School Rate SR-1a – Sheet 41

A-40. In the Application Date, Termination Section, the Applicant fails to provide a rationale for changing the term of the agreement to five years with a self-renewal provision for successive periods of two years. The Staff recommends that the Applicant provide rationale for this change.

Exceptions specific to Ohio Edison

A-41. The rates that are provided in UNB-1 have been rounded one decimal place to match those found in UNB-7. In comparing these schedules, some of the rates were rounded improperly. For example, in Rate 29 – Interruptible Arc Furnace Rate, the Distribution Charge on the UNB-1 is $0.00323. On UNB-7 the same charge is $.003235. The Staff recommends that the Applicant accurately represent all numbers in its final rates.

A-42. In its UNB-1 Schedule, Original Sheet No. 23, Pages 2 and 3 of 6, under Generation Charge: Capacity Charge, the rates did not reflect UNB-7. A data request was issued and revised sheets were provided that showed corrected figures. The Applicant needs to docket all revisions to the application.

UNB-2 - Scored copy of Current Tariffs

In accordance with rule 4901:1-20-03, Appendix A, Section (F), the Applicant filed UNB-2 schedules that provide a scored copy of its current tariffs. This section identifies Staff's exceptions to the UNB-2 schedules.

Exceptions specific to Toledo Edison

A-43. Several tariff rates filed in the UNB-2 schedule do not correspond with the Commission approved rates in effect as of October 4, 1999. Staff verified rate accuracy for all schedules in UNB-3.1 which utilizes the approved tariff rates to calculate total revenue by rate schedule. Staff requested correct tariffs in Data Request No. 59.

UNB-3 - Current bundled rates and billing determinants

In accordance with Section 4901:1-20-03**,** Appendix A, Section (F), the Applicant filed UNB-3 schedules which provide a summary of billing determinants and average rates for all schedules. The UNB-3.1 schedules provide rates and billing determinants for all schedules that were in effect in the last rate case. The UNB-3.2 schedules provide details on the schedules and contracts that have become effective since the last rate case.

The Staff found no exceptions to the Applicant's UNB-3 schedules.

UNB-4 - Cost of Service Study

In accordance with Section 4901:1-20-03, Appendix A, Section (F), the Applicant filed its UNB-4 schedules as part of its transition plan filing. The Applicant filed a bundled and an unbundled cost of service study in UNB-4 and UNB-4.1, respectively. The purpose of the studies is to utilize the cost of service study that was used in the Applicant's last rate cases as a basis to unbundle its current rates in a revenue neutral manner. The Applicant's starting point for the development of the unbundled rates is the bundled rate schedule-by-rate-schedule cost of service study Schedule UNB-4 that incorporates the revenue, expense and investment in the Commission's decision for the Applicant's last rate cases. The unbundled cost of service study, Schedule UNB-4.1 is then prepared by analyzing the schedule results from the bundled cost of service study on a functional basis, while maintaining the schedule-by-schedule relationships.

The Applicant utilizes the FERC Uniform System of Accounts (USOA) as a basis for unbundling most of the plant and expense accounts. The Applicant prepared several additional studies to develop more refined functional separations where the FERC USOA and / or the last rate case cost of service study do not provide the detail necessary to functionalize certain types of costs.

While the rules allow a utility to propose changes which alter its cost of service study and provide additional UNB schedules which reflect the modifications, the rules also require, at a minimum, that the cost of service study that was filed in the utility's last rate case, adjusted to support rates which were approved pursuant to the Commission order, be utilized for the purpose of unbundling rates. Applicant's unbundled cost of service study provided in UNB 4-1 reflects modifications made as a result of the functionalization studies which it has conducted. Overall, the studies result in a shift in the assignment of dollar amounts from the generation function to the distribution function. While the "allocation" of revenues to the various classes has not been affected, the functionalization necessary to unbundle rates within classes has been modified.

A-44. The proposed special studies were utilized to functionalize general plant, property insurance, property taxes, and deferred taxes. The Applicant also proposed to include the step-up transformer investment in the production function. The Staff does not recommend that these studies be utilized. The Applicant should provide an unbundled cost of service study that is unadjusted by the studies.

However, to the extent that the Commission finds the changes resulting from the studies to be reasonable, the Staff has reviewed these studies and has noted specific exceptions. In addition, if adjustments are deemed to be reasonable, the Staff has identified other accounts that should be reviewed for functionalization purposes. These accounts include the following:

Account 447 - Sale for Resale
Account 555 - Purchased Power Expense
Account 925 - Injuries and Damages Expense
Account 913 - Sales Expenses – Advertising

Account 930.1 – Miscellaneous General Expenses – Advertising
Account 930.2 – Miscellaneous General Expenses – Other
Account 303 - Intangible Plant
Ohio misc. taxes, Pennsylvania personal property taxes (PURTA), Pennsylvania real estate taxes; Pennsylvania sales and use tax; and Superfund Federal Excise tax

Following are the specific exceptions the Staff has identified for the five studies.

Exceptions to the General Plant Study specific to CEI

A-45. The Staff traced the general plant accounts to the 1997 FERC Form 1 and was able to reconcile the plant balances through the Applicant's workpapers. The Staff has examined the allocations and the methodologies used in the development of the study and found them to be reasonable with the exception of the generation, transmission and distribution allocator and the 1999 budget employee count allocator. However, the Staff has unanswered Data Requests 46 and 47. The staff has requested written explanations (with support) of the 1997 FERC Form 1 balances for the Generation and General Accounts and an explanation of why the Applicant uses 1999 budgeted employee counts. Also, the Staff has requested the 1997 employee counts, as well as the 1997 total company jurisdictional labor dollars compared to the corresponding labor dollars for generation, distribution, and transmission. The Staff recommends the generation, transmission and distribution allocators be based on respective plant balances reported in the 1997 FERC Form 1. The Staff also recommends that the generation, transmission and distribution labor dollars ratio be used instead of the 1999 budget employee count allocator.

Exceptions to the General Plant Study specific to Toledo Edison

A-46. The Staff discovered variances between amounts reported in the Applicant’s FERC Form 1 and its filing in this proceeding. General Plant allocated to the general function and the generation function varied from the FERC Form 1 by $7,300,000 and $1,292,519,574, respectively. The Staff used plant balances from the FERC Form 1 that were filed with the PUCO to compare to the Applicant’s filed information. Plant balances in the FERC Form 1 that were filed with the PUCO differ from those in the FERC Form 1. The Applicant used plant balances that were reported to FERC in developing their plant study. The Staff issued a data request asking the Applicant to explain the differences. The data request is pending.

A-47. The Applicant used 1999 employee data to develop labor ratios. The Applicant failed to provide a basis for using budgeted employee counts from 1999. The Staff issued a data request requesting the rationale for using 1999 data, and for a comparison of 1997 total company jurisdictional labor dollars compared to the labor dollars for generation, transmission and distribution. The data request is pending.

Exceptions to the General Plant Study specific to Ohio Edison

A-48. For the most part, the Staff was able to verify the mathematical accuracy and the validity of the calculations used in the Applicant's general plant study. However, the Staff was unable to tie plant balances used to calculate the VBM Overall Method Allocator, and used to assign general plant investment to the functions on a location by location basis, to the FERC Form 1. Staff submitted Data Request No. 30 to the Applicant on January 15, 2000, formally requesting the Applicant to provide an explanation of how they arrived at the generation and transmission dollar amounts used to calculate the VBM Overall Method Allocator. Additionally, the Staff requested the Applicant to provide any and all additional information and or guidelines used by Applicant's employees that assisted them in their functionalization of general plant investment. Finally, the Staff requested that the Applicant provide a detailed list of plant assets that comprise the "Unclassified" portion of General Office General Plant System, USOA Account 391.2, Page 36 of 102 of the Ohio Edison Plant Master List from the Company Applicant's General Plant Study. As of this date, the Staff has not received a response to its data request.

Exceptions to the Property Tax Study specific to Toledo Edison

A-49. The Applicant's workpapers (WP UNB-4K) indicate that property taxes associated with Materials & Supplies (M&S) were unbundled based on rate base additions associated with M&S. The Applicant did not state why this method of unbundling is more appropriate. The Staff found a slight variance in the unbundled amounts presented in the schedules and amounts calculated by applying rate base additions associated with M&S functional factors to total M&S property taxes.

Exceptions to the Deferred Tax Study Specific to CEI

A-50. Income tax deferrals were functionalized based on the same cost driver used to allocate each in the prior case, with the exception of income tax deferral 6. The prior cost of service study allocated each item included in tax deferral 6 based on payroll. However, currently each is functionalized based on plant. The Staff issued Data Request No. 36 requesting an explanation for the change in the cost driver. The Staff has yet to receive a response from the Applicant.

A-51. The Applicant functionalized each rate base deduction using the same cost driver used to allocate each in the previous case, with the exception of rate base deduction number 13. Rate base deduction 13 was functionalized based on plant rather than on payroll as previously allocated. The Staff has requested an explanation from the Applicant but has yet to receive a response. The Staff can not verify the validity of the functionalization of this deferred tax item until the Response to Data Request No. 36 is received.

Exceptions to the Deferred Tax Study specific to Toledo Edison

A-52. The Staff was not able to verify the Applicant's transmission and distribution split of accelerated depreciation, deferred tax expense or deferred tax balance - accelerated depreciation. The Staff was also unable to follow some of the calculations in the Tax Detail sheets of the workpapers. A data request is pending for both of these items.

A-53. The Staff noticed that S/L depreciation amounts from the Opinion & Order associated with the Beaver Valley 2 lease were not included by the Applicant's in its calculation. A data request for the Applicant's rationale for this treatment is pending.

<u>Other items contained within the UNB-4 Schedules</u>

A-54. FERC seven-factor test - 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 is required to "demonstrate that the facilities included for cost recovery in the transmission component are consistent with the FERC seven-factor test." FirstEnergy conducted the seven-factor analysis as part of the American Transmission System Inc (ATSI) filing at FERC, Docket No. ER99-2647. They did not, however, include this analysis as part of the its transition filing nor did they 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), Revised Code 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 and compliance with the rule requirements as found in Section 4901:1-20-03 (F)(2)(g) can occur. Recognizing the time requirements for such an endeavor, FirstEnergy should be required to begin the process by filing 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.

A-55. The Applicant's total revenue requirements requested in the last base rate case for Toledo Edison and CEI (Case No. 95-299-EL-AIR, Case No. 95-300-EL-AIR) were less than the Applicant could have justified. The resultant rate of return derived from the new rates was 9.09% for CEI and 9.26% for Toledo Edison. This was less than the 10.06% authorized by the Commission. In the bundled cost of service study Schedule UNB 4, the resultant overall weighted average rate of return for all rates schedules equals 9.09% and 9.26%. The Applicant calculated the transmission and distribution revenue requirements by applying the basic ratemaking formula to the rate base and income components as identified in the unbundled cost of service study Schedule UNB 4.1. The Applicant used the 10.06% rate of return to calculate the transmission and distribution revenue requirements. As a result of using the 10.06% rate of return for the transmission and distribution functions, the production revenue requirement produces a rate of return lower than the 9.09% and 9.26% rate of return that resulted from the last rate case. The Staff recommends that the 9.09% and 9.26% rate of return for CEI and Toledo Edison, respectively, should be used to calculate the revenue requirements for the production, transmission, and distribution functions.

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-4 and 4.1 schedules 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.

Exceptions common to CEI, Toledo Edison, and Ohio Edison

In its application, the Applicant has treated generation, which Staff refers to as "little g" ("little g" = G-RTC-GTC) as a residual amount. The Applicant has calculated a specific GTC revenue requirement amount to be collected annually over a five-year period. In addition, it has calculated the revenue requirement for RTC for each class that is required 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 GTC and RTC, and the remaining revenues are considered "little g".

A-56. For unbundling purposes, Staff recommends that the GTC rate for each rate schedule be determined by taking the generation revenue requirement (GTC, RTC and "little g") for each schedule and subtracting out the RTC revenue requirement and the revenue requirement associated with the market rate. The GTC 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 the same percentage 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 GTC, RTC and "little g", the residual amount.

A-57. Firm special contracts should be unbundled based on the tariff rate schedule they would have been served under absent a special contract, which will be referred to as the "fall-back schedule". The rates that current contract customers are paying can only be adjusted in accordance with the exceptions as provided for in Section 4928, Revised Code (Taxes, USF, EEF). To determine GTC and RTC revenue recovery from the firm contracts, the GTC and RTC rates that are effective for the appropriate fall-back schedules should be utilized.

A-58. Non-firm special contracts should be unbundled based on the tariff rate schedule they would have been served under absent a special contract, which will be referred to as the "fall-back schedule". The rates that current contract customers are paying can only be adjusted in accordance with the exceptions as provided for in Section 4928, Revised Code (Taxes, USF, EEF). To determine the GTC and RTC revenue requirement for these customers, Staff finds that the rationale that applies to allocating production demand costs to the interruptible customers which results in interruptible customers being allocated twenty-five percent of their demand responsibility in Ohio Edison's case and zero percent demand responsibility in Toledo Edison and CEI, also applies in allocating the GTC and RTC revenue requirements. Therefore, for the interruptible portion of customer contracts, for CEI and Toledo Edison, there will be no GTC or RTC assigned. For Ohio Edison, twenty-five percent of the GTC and RTC will be assigned to the interruptible portion of customer contracts. However, the RTC should be allocated to the various classes based on how it was allocated in the last rate case COSS. To the extent that any items that are included in the RTC were not allocated to the classes based on a production demand allocator, and were allocated to the non-firm contract customers, then such items should be allocated to those customers on the same basis.

Allocation of GTC to the various classes

A-59. In its application the Applicant has developed a specific GTC amount, allocated that amount across the classes based on energy usage, and finally designed GTC rates to recover that amount. Although Staff's method of determining the GTC revenue requirement for each class is different than the Company's proposal as described above, the total GTC amount that is calculated for the company in total should be allocated across the classes so that it can be determined when each class has contributed its share of the total GTC revenue requirement, resulting in the end of the MDP for each class. The GTC should be allocated across the classes based on a production demand allocation as opposed to an energy allocation since the production demand allocation would be more reflective of how the GTC is currently contained in base rates.

RTC Allocation to the classes

A-60. In its application, the Applicant has developed a total RTC revenue requirement. It then allocates that requirement to the classes based on an energy allocator. Staff recommends that the RTC revenue requirement be allocated to the classes on the same basis that they are currently allocated in base rates as opposed to strictly an energy allocator.

Unbundled Transmission Rate Development Issues

The Applicant's unbundled transmission rates are based on the Applicant's OATT revenue requirements. From those revenue requirements, the Applicant developed transmission rates for the various customer classes of each operating company. The unbundled transmission rates were developed in such a way as to achieve the revenue requirements of the OATT. Unbundled bulk and 69 kV transmission rates were developed separately, from the separate revenue requirement levels that are listed in the OATT.

The Applicant based its ancillary service revenue requirement calculations on its OATT ancillary service rates and the average monthly coincident peak levels of the FirstEnergy operating companies. The Applicant multiplied the average monthly coincident peak levels for each operating company by the OATT ancillary service rates in order to determine operating company ancillary service revenue requirements. These operating company ancillary service revenue requirements were distributed among customer classes of each operating company to develop unbundled ancillary service revenue requirements and rates.

A-61. Staff found two inconsistencies in the Applicant's unbundled ancillary service rate development. One inconsistency is that the ancillary service rates that were used in the unbundling calculations were not actually those that are in the companies' OATT. It is Staff's understanding that the ancillary services rates provided in the supporting workpapers are the rates that were originally submitted by the Applicant in its initial OATT application. However, these are not the rates that are in their current OATT application, and are not the rates that are anticipated to be approved by FERC.

The second inconsistency is that the method that the Applicant used to develop ancillary service revenue requirements resulted in monthly revenue requirements. However, those monthly revenue requirements were applied by the Applicant as if they were annual revenue requirements. Therefore, the Applicant's unbundled ancillary service revenue requirement levels and rates are understated by a factor of 12.

Staff recommends that the unbundled ancillary service rates be modified to reflect the appropriate OATT ancillary service rates. Further, Staff recommends that the companies' ancillary service revenue requirements be revised to reflect appropriate annual levels.

Comparing UNB-5 Schedules to the UNB-4 Schedules

A-62. Staff compared the unbundled revenues in UNB-5.1 to the unbundled cost of service revenues in UNB-4.1. The unbundled components for generation, transmission and distribution for each schedule were compared. In comparing these schedules, Staff was unable to match several class revenues by function. Data Request Nos. 28, 40, 43, and 50 were submitted requesting the Applicant to reconcile totals or explain differences

A-63. In its rate schedules that provide for voltage discounts the Applicant has accounted for such discounts in its UNB-5 schedules by reducing the billing determinants. For example, in its UNB-5.1a schedule for Ohio Edison Rate 23, the Applicant has utilized different billing determinants than it did in the UNB-3, UNB-5.1b, or UNB-7 Schedules. This has resulted in higher transmission, distribution, GTC, and RTC revenues, therefore, resulting in an understatement of generation revenues and rates. The Staff recommends that the Applicant utilize the same billing determinants consistently throughout the schedules.

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. Once the current rates were unbundled into the various components, as detailed in the UNB-5 schedules, adjustments 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 is a brief discussion of the tax changes and how the Applicant incorporated such changes into its current rates.

Exceptions common to CEI, Toledo Edison, and Ohio Edison

Tax Law Changes

A-64. Staff finds that, pursuant to Section 4928.34 (A) (6), rates may be adjusted for any changes in the taxation of electric utilities resulting from the legislation. Staff recommends that the methodologies utilized in making the tax-related adjustments (i.e. those related to property taxes, the gross receipts tax, the corporate franchise tax and the municipal income tax) to current rates should be consistent. For example, if the revenue removed from rates due to changes in the property tax adjustments is based on current property tax expenses, the revenue removed from rates due to the elimination of the gross receipt tax should also be based on current revenues.

State and Local Tax Rider

A-65. In its proposed rate schedules the Applicant has included a state and local tax rider. In the section of the rider pertaining to the state kWh tax, the Applicant is proposing to include an Ohio gross receipts tax rider, that will be effective from January 1, 2001 through April 30, 2001, that reflects the statutory tax rate. Staff recommends that the Applicant include the effective gross receipts tax rate net of uncollectibles and non-taxable receipts.

A-66. Also in this rider the Applicant is proposing to include a municipal distribution tax. The Staff recommends that the municipal distribution tax not be included as a rider, but should be built into the Applicant's base rate charges.

Franchise Tax

A-67. At this time, the Staff believes the Applicant's overall process used to determine its franchise tax liability is appropriate. The Staff is of the opinion that the Applicant's estimate of the tax liability is reasonable. Therefore, the Staff believes the Applicant's estimate of franchise tax expense as shown on their UNB-4.1 Schedules to be appropriate for setting future electric rates. However, the Applicant has not responded to Staff's Data Request No. 48 requesting additional information regarding this subject matter. Staff will make its final recommendation regarding this issue after it has had an opportunity to review and analyze the information requested in the above referenced data request.

5% Residential Reduction

A-68. The Applicant has adjusted rates for residential customers by applying a 5% reduction to "little g" after tax adjustments and the Applicant's approved rate plan reductions. 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 GTC and RTC.

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 will be based more on the "methodology" of unbundling, rather than precise rate levels.

Following is a discussion of the Staff exceptions to the Applicant's filed UNB-7 schedules.

Exceptions common to CEI, Toledo Edison and Ohio Edison

A-69. In its filing there are a number of instances where the rates or rate structures that are contained in the Applicant's UNB-7 Schedules are not consistent with UNB-1 Schedules. For example, for CEI, Small and Large School Rates, in the UNB-7, the Applicant has included ancillary service charges based on demand (kW), however, in the UNB-1 Schedules the same charges are based on Consumption (kWh). The Staff recommends that the Applicant ensure that the final rates and rate structures are consistent between the UNB-1 and UNB-7 Schedules.

A-70. In developing its final rates for the UNB-7 schedule which are to reflect the rates the Applicant will provide in its filed tariff schedules, the Applicant utilized the unbundled rates that were developed in the UNB-5 schedules and adjusted the rates for the tax changes. An additional adjustment was made to the "little g" and GTC rate if the "little g" was higher than the shopping credit as calculated by the company. For example, if "little g" was higher than the shopping credit, then "little g" was reduced to equal the shopping credit and a corresponding increase was applied to the GTC rate. Staff's methodology of calculating the GTC rate as described earlier in the UNB-5 section eliminates the need for such an adjustment since the GTC rate will be equal to the Big G rate minus the RTC rate and the market rate.

Exceptions specific to CEI

A-71. The Optional Electric Process Heating and Electric Boiler Load Management Schedule's Distribution charge: The energy charge for the first 140 kWh per kW of monthly billing demand listed in the UNB-1 Schedule does not match the charge listed in the UNB-7.1 Schedule. Staff issued Data Request No. 55 to reconcile the differences and is still waiting on a response.

UNB-8 Typical Bill Comparisons

A-72. In accordance with Rule 4901:1-20-03, Appendix A, Section (F), the Applicant provided UNB-8 schedules in its transition plan filing. In the Applicant's UNB-8 schedule the typical bills provided for each schedule reflect current bills that include the rate plan reductions that will be effective on average during the year 2001. The proposed bills reflect the final rates as provide in Schedule UNB-7 and also include the same rate plan reductions on average during the year 2001. The residential proposed bills also include the effects of the mandated 5% residential reduction.

Exceptions common to CEI, Toledo Edison, and Ohio Edison

A-73. Several typical bills show disparity. Staff and the Applicant have scheduled a meeting to discuss those disparities.

Other Issues Not Addressed in the UNB Schedules

A-74. 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 be or should not be unbundled portions of the distribution function.

ATA Application

In Case No. 99-1213-EL-ATA, the Applicant has requested authority to; (1) withdraw certain of its rate schedules; (2) approve the proposed rates, rules and regulations for all companies; and, (3) approve the proposed Electric Generation Supplier Coordination Tariff.

In regard to item (1) Staff has requested rationale for the Applicant's request to withdraw the various rate schedules. In regard to item (2) the staff does find exception to its proposed rates, terms and conditions as outlined throughout this report. In regard to item (3) Staff has provided certain exceptions to the Supplier Coordination Tariff, however, it recognizes that as stated in the Operational Support Section of the Report, there are established working-groups analyzing this tariff and further recommendations may come in the future.

Part B – The 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.

The Applicant's Transition Plan filing is required to address these objectives.

Summary Description of the Applicant's Corporate Separation Plan

FirstEnergy plans to comply with the corporate separation rules, during an interim period, by establishing three business units: a competitive service unit, a corporate support service unit and a utility service unit. The utility will transfer operating controls over all competitive assets (which are primarily generating assets) to a competitive services unit. The competitive service unit will be responsible for all operating and maintenance expenses, taxes and capital costs attributable to these generating assets. The competitive unit includes all commodity sales, marketing, generation and gas production and transportation resources, trading and sourcing of commodity requirements, and all other competitive services such as HVAC enterprises. FirstEnergy has stated that separate locations will be established for the affiliates and if space is shared with the utility, employees will be required to comply with the code of conduct.

The corporate support unit, according to FirstEnergy, will be comprised of all elements of the organization that are responsible for the corporate related functions that are and will be shared by both the competitive services and the utility services unit (accounting, legal information systems, etc).

The utility service business unit will include the electric distribution utilities, Toledo Edison, CEI, Ohio Edison, Pennsylvania Power (Penn Power), and American Transmission Systems, Inc. (ATSI). It should be noted that FirstEnergy still plans to eventually dissolve ATSI into a regional transmission organization. Responsibilities of the utility service business unit include the design, construction, operation and maintenance of the distribution and transmission systems and certain other distribution electric services (other services). The other services contemplated include substation design and construction, customer equipment maintenance and repair, customer distribution equipment service upgrades, power quality maintenance and improvement, and power systems and safety training. These other distribution services will be provided at prices negotiated with customers, but the Applicant stated that in no event would the price be less than the Applicant's fully allocated cost. FirstEnergy, witness Michael S. Hyrnick stated in direct testimony, that he does not believe the Staff intended to have the code of conduct to apply to interaction between affiliated electric utilities.

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.[1] These restrictions among other things, seek to eliminate the exposure to the electric utility based on actions of a competitive business, and require the competitive businesses to obtain financial arrangements that better reflect their business risk. 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 financial arrangements that appear to be in violation to the current rules. These arrangements include sale-leaseback transactions, pollution control notes and mortgage bonds. Pollution control bonds lower the cost of capital because they are tax-exempt and mortgage bonds are 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 FirstEnergy's electric utilities should separate their financial arrangements as quickly as possible, some flexibility may be warranted. For example, if the Commission required immediate (or even on or before a specified date) that CEI tender[2] for its first mortgage bonds, it could increase transition costs dramatically, due to potentially poor market conditions and may, 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 in the open market because of the Security and Exchange Commission requirements which require fairness to all classes of bond holders.

---

[1] 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.

[2] 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.

Therefore, due to the first mortgage liens, FirstEnergy may be unable to transfer it's generating assets to the competitive affiliate on or before 2001 (operating control will be granted to the competitive business unit on or before January 1, 2001), FirstEnergy would instead choose a functional interim plan. According to FirstEnergy, during the interim period the financial arrangements and obligations of the operating companies will be restructured and assigned to each business unit. The competitive service unit and corporate support business unit will assume, through direct assignment, sublease, or other contractual arrangements, its proportionate share of the operating companies' financial obligations. The existing liabilities of the operating companies, e.g., first mortgage bonds, notes, and preferred stock, will continue to remain with the operating companies until these overlapping obligations can be economically terminated, replaced or refinanced. While the existing contractual terms of the financial arrangements remain unchanged between the operating companies and their obligees, the appropriate business units will be obligated to the operating companies to service their respective financial obligations.

Similarly, FirstEnergy's interim plan seeks to separate the sale/leaseback obligations of the operating companies (relating to the Perry, Beaver Valley, and Mansfield power plants) so that the competitive service business unit is contractually obligated to fulfill the lease obligations of the regulated operating companies. This interim plan may be subject to increased Staff monitoring, with an ongoing obligation of FirstEnergy to demonstrate why full structural separation has not yet occurred.

Staff's Exceptions and Recommendations

B-1. The Staff believes the utility business unit, as proposed by FirstEnergy, should not be providing other negotiated services including substation design and construction, customer equipment maintenance and repair, customer distribution equipment service upgrades, power quality maintenance and improvement, and power systems and safety training. Staff believes that it is more appropriate for FirstEnergy's competitive unit to provide these services and that the customer should be informed that these are competitive services that can be performed by other businesses. However, as the rules permit, employees and equipment of the utility may be used to perform these services, subject to proper accounting and adherence to the code of conduct. As stated in Commission's Corporate Separation Rules, "The affiliate standards shall also apply to any internal merchant function of the electric utility whereby the electric utility provides a competitive service." Staff believes that this applies to transactions between electric utilities when internal merchant functions (including all competitive services) are involved.

B-2. The Staff believes that it is prudent to allow FirstEnergy to use an interim functional separation plan, due to some of its current financial arrangements. However, during this time of functional separation, additional monitoring is warranted, with particular attention being paid to the cost of capital of each business, such that it reflects the market risks of the each business unit. For example, the utility service unit companies, with their guaranteed cash flows should experience a significantly lower cost of capital.

Part C – Operational Support 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 systems to permit certified suppliers and the Companies to handle customer information in an efficient manner.

Summary Description of the Applicant's Operational Support Plan

The Applicant's proposed plan includes new systems, protocols, and procedures that allow customer choice to be implemented in a timely and effective manner. It describes how the Applicant plans to meet the operational and technical implementation provisions of restructuring pursuant to the requirements of Commission Rule Section 4901:1-20-03 Appendix C. The plan is to ensure the deployment of operational support needed to successfully implement restructuring. The plan is described and supported in the testimony of Applicant witness Green.

Staff's Exceptions and Recommendations

The Staff is currently conducting a workshop 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 does not have any specific exceptions or recommendations to the Applicant's Operational Support Plan.

Part D - Consumer Education Section

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 PUCO, in consultation with the Ohio Consumers' Counsel (OCC), will oversee this consumer education effort. 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 must ultimately approve 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 Applicant's Consumer Education Plan

FirstEnergy 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.

FirstEnergy's contact for the program will be Thomas M. Welsh, manager of communications for the Applicant. FirstEnergy proposes to establish an advisory group made up of a Staff representative, OCC representative and at least two customer representatives, specifically of the "hard-to-reach" target audiences listed in the General Plan for Consumer Education. The advisory group is scheduled to meet quarterly to provide input regarding the goals and messages of the campaign. Staff will work with FirstEnergy to ensure that the group meets often enough to have meaningful input.

FirstEnergy proposes to utilize tactics including mass media advertising, direct mail, bill inserts, special promotional events, speaker's bureau presentations and news releases. The schedule and frequency for implementing these tactics will be developed after benchmarking surveys have been done. FirstEnergy 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.

FirstEnergy proposes to begin the service territory-specific campaign after the statewide campaign kicks off in July 2000, but not later than the beginning of the third quarter in 2000. More detailed timeline information will be provided by the Applicant following the benchmark surveys.

FirstEnergy proposes to provide $7.2 million, or 45%, of the first year $16 million for consumer education and $7.65 million thereafter for the remaining transition period.

Staff's Exceptions and Recommendations

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

Part E - Employee Assistance Plan

Introduction

Section 4928.31, Revised Code requires 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 yet been appointed.

Summary Description of the Applicant's Employee Assistance Plan

FirstEnergy does not have any immediate plans to downsize its workforce so it has not included any costs for downsizing for transition cost recovery. FirstEnergy, through its witness, Mr. Bowers, describes how it would implement its downsizing plan if it becomes necessary. First, FE would consider a voluntary retirement program similar to the plans that it has offered in the past. Next, it would decide if it could retain its current employees in other positions. Last, the Applicant would enact involuntary workforce reductions.

Employees that are affected by restructuring would be eligible for the Applicant's employee assistance plan (EAP). This EAP has three (3) components. They are retention, financial assistance, and transition support services and they are detailed in the Applicant's testimony.

Staff's Exceptions and Recommendations

The Staff is ready to assist the Employee Assistance Advisory Board with any technical assistance that the 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 FirstEnergy's employee assistance plan.

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 costs that meet 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, FirstEnergy'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 FirstEnergy 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 FirstEnergy's proposed accounting authorizations.

Methodological Exceptions

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

- An "initially derived" Generation Transition Charge (GTC)[3] is determined, such that the entire amount of transition costs not included in regulatory assets is recovered during the market development period.
- The existing rates are unbundled into Transmission & Distribution, Generation, and other charges.
- Distribution is determined by application of the FERC Transmission rate, which is subtracted from the unbundled Transmission & Distribution rate, as discussed in Section 4928.34, Revised Code.
- The regulatory asset charge (referred to as Regulatory Transition Charge, or RTC) is determined, per Section 4928.39, Revised Code.
- A rate is developed, that is variously referred to in FirstEnergy's testimony as "Shopping Credit", "Market Rate", "Unbundled Generation", or "initially determined G"[4], which is developed by subtracting the GTC and RTC from the Generation component determined in the unbundling process.
- Under FirstEnergy's methodology, their proposed RTC and GTC appear to be considered "other unbundled components" as identified in Section 4928.34(A)(4), Revised Code.

[3] This charge is functionally equivalent to, but derived differently from, what is identified elsewhere in this report as a Competitive Transition Charge, or CTC.

[4] This factor is described elsewhere in this report as "little g". In the Staff's terminology,
"little g" = (Unbundled Generation – Regulatory Transition Charge – Competitive Transition Charge)

- A “Shopping Credit” is determined independent of this process.
- Where the “initially determined G” exceeds the “Shopping Credit”, the “initially determined G” is reduced to the level of the “Shopping Credit”, and the difference is added to the GTC.
- Where the “Shopping Credit” exceeds the “initially determined G”, the “Shopping Credit” is set to equal the “initially determined G”.
- The reduction in residential rates described in Section 4928.40(C), Revised Code is calculated on the “initially determined G”

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, the transition cost related component of unbundled rates is determined by 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 4928.39(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 FirstEnergy’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 FirstEnergy 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. In addition there is no provision in Section 4928, Revised Code for an adjustment of the shopping incentive up or down based on the results of the unbundling process.

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 FirstEnergy does neither.

F-4. FirstEnergy'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 "initially determined G", rather than to a proper unbundled generation figure.

Determination of Costs Not Recoverable Under Competition

F-5. Of its investment in generation facilities, FirstEnergy has valued the portion that is recoverable in a competitive market to be $2.9 billion. This represents 38% of the FirstEnergy's book investment, net of regulatory assets and other adjustments. It also represents an economic value of approximately $107 per kW of capacity for nuclear plant, and $345 per kW of capacity for its other plant, which is mainly coal.

Research Data International (RDI), the Staff's consultant, has conducted an analysis that indicates economic capacity values above those claimed by the Applicant. Based upon this analysis, the Staff takes exception to the Applicant's valuations. These valuations, particularly the non-nuclear valuations, understate the value that these facilities have in a competitive market, both in the most likely competitive market for electricity in the future and the competitive market for generation assets which exists at present.

The RDI analysis is in the process of being augmented by additional company-specific data. Because the current analysis is preliminary, the Staff does not believe it appropriate to publish specific valuations for the Applicant's generation plant at this time. However, the Staff plans to hold meetings on this matter with technical personnel of the Applicant and the intervening parties to this case. By identifying and discussing the technical causes for the differences in valuations, the Staff believes that clearer and more accurate valuations will be made possible for use in these proceedings.

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.

The Staff has identified a number of instances where the Applicant's determination of regulatory assets for recovery in transition revenues is incorrect, inappropriate or has been insufficiently supported. These instances are detailed below. The current basis for some of the exceptions is that the figures are inadequately supported. The provision of additional information may resolve these exceptions, or may reveal additional bases for exception.

F-6. Gross Receipts Taxes – FirstEnergy has requested that this amount be included as a transition cost claiming that it is a prepaid balance for these taxes. The Applicant bases its claim on its accounting for this item. The Staff recommends that this item not be included in the transition costs nor that this item be recovered by either a continuation of the gross receipts surcharge or 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-7. Consumer Education - FirstEnergy requested inclusion of these costs in regulatory assets, with recovery through the RTC. The Staff takes exception to this treatment, as these costs do not meet the tests outlined in Section 4928.01(A)(26), Revised Code, nor are they specifically identified as regulatory assets within that section. The Staff recommends that these costs be considered for deferral, subject to the company showing a material financial impact on its regulated business sectors, for possible future recovery under the auspices of a distribution rate case proceeding.

F-8. Customer Billing System Enhancement - FirstEnergy requested inclusion of these costs, which involve adapting and modifying the existing customer billing system for continued use in a restructured environment, in regulatory assets, with recovery through the RTC. On review, the Staff is of the opinion that these costs are most appropriately viewed as distribution company costs. In addition, these costs do not meet the tests outlined in Section 4928.01(A)(26), Revised Code, nor are they specifically identified as regulatory assets within that section. The Staff recommends that these costs be considered for deferral, subject to the company showing a material financial impact on its regulated business sectors, for possible future recovery under the auspices of a distribution rate case proceeding.

F-9. Postretirement Benefits – FAS 106 - FirstEnergy included deferred postretirement benefits in its rate plan as a regulatory asset. Deferral of these costs was approved in Case No. 91-1751-AU-COI. These deferrals were granted to the extent that each company's return on average common equity did not exceed the rate of return authorized in each company's previous respective rate proceedings. In addition, in Case Nos. 95-299-EL-AIR and 95-300-EL-AIR for Toledo Edison and CEI respectively, portions of the postretirement benefits were excluded from deferral as they related to Centerior Service Corporation employees. Upon review, the Staff takes exception to the following aspects of the Applicants' inclusions:

CEI included deferrals for the years 1994 and 1995. By the Staff's calculations, CEI's return on average common equity for these years exceeded the approved rate of return, making these costs ineligible for deferral.

Toledo Edison failed to take into account the exclusion of postretirement benefits for Centerior Service Corporation employees from their calculation of 1995 deferrals.

F-10. Energy Imbalance System - FirstEnergy requested inclusion of these costs in regulatory assets. These costs, with recovery through the RTC, reflect adapting and modifying the existing energy imbalance system for continued use in a restructured environment. On review, the Staff is of the opinion that these costs are most appropriately viewed as distribution company costs. In addition, these costs do not meet the tests outlined in Section 4928.01(A)(26), Revised Code, nor are they specifically identified as regulatory assets within that section. The Staff recommends that these costs be considered for deferral, subject to the company showing a material financial impact on its regulated business sectors, for possible future recovery under the auspices of a distribution rate case proceeding.

F-11. Employee Assistance Costs - FirstEnergy has requested inclusion of these costs in regulatory assets. However, no specific dollar figure was identified for recovery. In addition, there is no indication of how FirstEnergy proposes to make the determination that whatever costs will ultimately be considered for recovery will be tested for compliance with the criteria listed in Section 4928.39(D), Revised Code. To the extent that such an inclusion is unsupported, the Staff takes exception to it.

F-12. Perry Deferred Operation and Maintenance Expenses - CEI and Toledo Edison included the unrecovered balance of Perry deferred operation and maintenance expenses. These expenses were incurred from the in-service date of the unit, June 1, 1987, to its inclusion in rates effective December 22, 1987. At the time of this writing, the Staff has not yet received a response to its Data Request No. 35, which would allow the Staff to confirm the appropriateness of the figures included by the Applicant. Therefore, the Staff takes exception to the inclusion of these amounts, to the extent they remain unsupported.

F-13. DOE Decommissioning And Decontamination - FirstEnergy included in regulatory assets the total allocated assessment from the Department of Energy for the eventual decommissioning of the DOE's fuel enrichment facilities, less the payments made by the Applicant to date. These payments are currently recovered as incurred through the EFC mechanism, and are not a result of any order by this Commission. Therefore, these costs are not regulatory assets as defined by Section 4928.01(A)(26), Revised Code. In addition, the Staff has not at this time been able to ascertain with certainty that these costs were not included in the cost estimates used in the determination of the market valuation of generation assets. The Staff takes exception to their inclusion as regulatory assets and inclusion in the determination of the RTC, as noted elsewhere.

F-14. Nuclear Decommissioning Costs - FirstEnergy included amounts reflecting updated estimates of decommissioning costs, adjusted for estimated future returns on amounts deposited in external trust funds, and the amounts already held in those funds. While the Staff agrees that the decommissioning cost studies are due to be updated, and does not object to the estimates arrived at, SB3 is explicit in limiting the inclusion in regulatory assets of these balances "as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs;...". Therefore, the Staff must take exception to the inclusion of the updated estimates in the determination of regulatory assets. In addition, as discussed elsewhere, the Staff takes exception to the use of these adjusted figures in the determination of the RTC.

F-15. Deferred Nuclear Units Costs - In the late eighties and early nineties, the companies filed various cases (87-109 & 110-EL-AAM, 87-111 & 112-EL-AAM, 87-984 & 985-EL-AAM, 87-1269 & 1270-EL-AAM, 87-1273 & 1274-EL-AAM, 88-506-EL-AAM, 90-1634-EL-AAM, and 92-1424-EL-AAM) requesting permission to defer operating expenses and capitalize post-in-service carrying charges associated with their ownership of the Perry Nuclear Power Plant and the Beaver Valley 2 Nuclear Power Plant. Such deferrals and carrying charges were to cover costs incurred from the in-service or partial in-service dates until the date investments were included in rates.

As part of this, carrying charges were authorized in Ohio Edison's Case No. 90-1634-EL-AAM and 92-1424-EL-AAM on deferred Perry and Beaver Valley 2 operating costs incurred after the end of the base rate case test year to the date rates were authorized in Case No. 89-1001-EL-AIR. Accrual of such charges ended in October 1995, when in Ohio Edison's Case No. 95-830-EL-UNC, the Commission authorized amortization of these amounts.

Regarding the amortization granted by the Commission in Case No. 95-830-EL-UNC, the parties signing the stipulation recommended that Ohio Edison be authorized to accelerate amortization of the deferred regulatory costs. There were no conditions on this acceleration. Therefore the Staff is of the opinion that the accelerated amortization should have occurred. At the time of this writing, the Staff has no indication that the balances proposed by Ohio Edison in this filing reflect any such acceleration. To this extent, the Staff takes exception to their inclusion.

F-16. Deferred Rents for BV2 & Mansfield - In Case Nos. 95-299 & 300-EL-AIR for Toledo Edison and CEI, respectively, the companies included and the Commission approved the date certain balances for Bruce Mansfield Gain & Deferred Rents. The amounts of ($235,139,000) for Toledo Edison and ($399,158,000) for CEI, both booked to Account 253-Other Deferred Credits, were used as rate base reductions. The deferred rents portions (($55,330,000) for Toledo Edison and ($85,052,000) for CEI) reflect the difference between actual and levelized lease payments, thus representing excess customer provided funds.

In the current proceeding, FirstEnergy has excluded Account 253 - Deferred Rents from consideration in both identifying the unbundled RTC and identifying the December 31, 2000 balance of transition costs. The Staff believes that since it was the Commission who authorized the levelization of sale/leaseback expense, it is entirely appropriate to incorporate deferred rents as a regulatory asset basis for transition costs and rates. The Staff, therefore, takes exception to the exclusion of this item.

F-17. Above Market Purchased Power Contract - FirstEnergy has included a portion of CEI’s purchase of 150 MW of Beaver Valley Unit 2 capacity owned by Toledo Edison in CEI’s regulatory asset balances for recovery through the RTC mechanism. The portion included in CEI’s regulatory assets reflects the estimate by FirstEnergy of the extent to which the cost of that transfer is at greater than market prices. FirstEnergy has at the same time taken this transfer into account in its GTC calculation for Toledo Edison.

However, as the Staff takes exception to the methodology and rationale for FirstEnergy’s GTC determination, the Staff takes exception to this adjustment. The Staff is of the opinion that the Commission should determine the regulatory asset for CEI, and the reduction in Toledo Edison’s other transition costs on the basis of the Staff’s market valuation of the assets.

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 FirstEnergy's case, the Staff believes that this requires that the RTC be determined based upon the recovery of regulatory assets as identified in Ohio Edison's Case No. 89-1001-EL-AIR, CEI's Case No. 95-300-EL-AIR, and Toledo Edison's Case No. 99-299-EL-AIR.

In light of the foregoing discussion, the Staff takes exception with 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 exceptions in this section are only with regard to the inclusion of these items in the determination of appropriate RTC values. Unless noted elsewhere, the Staff does not take exception to the inclusion of these items in the determination of Transition Costs.

Ohio Edison

F-18. Nuclear Decommissioning – FirstEnergy utilized an amortization based on their updated nuclear decommissioning cost estimates in determining their proposed RTC. The Staff takes exception to the use of the updated amortization, as it is not included in current rates, and therefore is not appropriate for inclusion as part of the determination of an RTC. The Staff is of the opinion that the amortization amount included in the determination of the current rates should be used.

F-19. DOE Decommissioning – FirstEnergy included DOE decommissioning and "decontainment" costs in it's determination of its proposed RTC. As noted elsewhere, the Staff takes exception to the inclusion of this assessment in regulatory assets, and therefore takes exception to their inclusion in the determination of an appropriate RTC.

F-20. FirstEnergy updated certain allocation factors in the determination of their proposed RTC. The Staff takes exception, and recommends that the Commission recognize only those jurisdictional allocation factors used in last rate case.

F-21. FirstEnergy calculated the amortization of Nuclear Safety and Radiation Control Equipment by calculating a ratio of year 2001 projected depreciation expense to projected year 2001 gross plant, and applying that ratio to date certain plant balances. The Staff takes exception to this, and recommends that the

Commission determine the amortization of Nuclear Safety and Radiation Control Equipment by applying the approved depreciation accrual rates for the respective plant accounts to the date certain plant balances from Case No. 89-1001-EL-AIR for the identified Nuclear Safety and Radiation Control Equipment.

F-22. The Staff takes exception to FirstEnergy's recognition of FAS 109 costs in the determination of its proposed RTC, to the extent it is affected by the above exceptions.

CEI

F-23. Bruce Mansfield and Beaver Valley 2 deferred rents - Bruce Mansfield and Beaver Valley 2 deferred rents portion of Account 253-Other Deferred Credits that were used as Other Rate Base Items offsets in Case No 95-300-EL-AIR. As noted elsewhere, FirstEnergy did not include these items in the determination of transition costs. As the Staff takes exception to the exclusion of these items in the determination of transition costs, the Staff takes exception to the exclusion of these items in the determination of an appropriate RTC.

F-24. DOE Decommissioning – FirstEnergy included DOE decommissioning and "decontainment" costs in it's determination of its proposed RTC. As noted elsewhere, the Staff takes exception to the inclusion of this assessment in regulatory assets, and therefore takes exception to their inclusion in the determination of an appropriate RTC.

F-25. Demand Side Management (DSM) Costs – FirstEnergy included DSM costs in determining its proposed RTC that reflected the unadjusted date certain balance from Case No. 95-300-EL-AIR. The Staff takes exception to this amount and recommends that the adjusted date certain amount from last rate case be used.

F-26. FirstEnergy did not include a balance of deferred First Mortgage Bonds costs in the determination of their proposed RTC. These deferred costs were included in rate base in Case No. 95-300-EL-AIR. The Staff takes exception to the exclusion of these deferrals in the determination of the RTC, and recommends that the Commission reflect the inclusion of these deferrals, as reflected in the last rate case, in the determination of an appropriate RTC.

F-27. Refueling Outage Accrual Balances – FirstEnergy excluded the effect of the normalization of nuclear refueling outages on Other Rate Base Items in Case No. 95-300-EL-AIR from the determination of its proposed RTC. The Staff takes exception to the exclusion of the effect of this offset, as it was a part of the determination of current rates, and therefore should be a part of the determination of an appropriate RTC.

F-28. FirstEnergy updated certain allocation factors in the determination of their proposed RTC. The Staff takes exception, and recommends that the Commission recognize only those jurisdictional allocation factors used in last rate case.

F-29. FirstEnergy calculated the amortization of Nuclear Safety and Radiation Control Equipment by calculating a ratio of year 2001 projected depreciation expense to projected year 2001 gross plant, and applying that ratio to date certain plant balances. The Staff takes exception to this, and recommends that the Commission determine the amortization of Nuclear Safety and Radiation Control Equipment by applying the approved depreciation accrual rates for the respective plant accounts to the date certain plant balances from Case No. 95-300-EL-AIR for the identified Nuclear Safety and Radiation Control Equipment.

F-30. The Staff takes exception to FirstEnergy's recognition of FAS 109 costs in the determination of its proposed RTC, to the extent it is affected by the above exceptions.

Toledo Edison

F-31. Bruce Mansfield and Beaver Valley 2 deferred rents - Bruce Mansfield and Beaver Valley 2 deferred rents portion of Account 253-Other Deferred Credits that were used as Other Rate Base Items offsets in Case No 95-299-EL-AIR. As noted elsewhere, FirstEnergy did not include these items in the determination of transition costs. As the Staff takes exception to the exclusion of these items in the determination of transition costs, the Staff takes exception to the exclusion of these items in the determination of an appropriate RTC.

F-32. DOE Decommissioning – FirstEnergy included DOE decommissioning and "decontainment" costs in it's determination of its proposed RTC. As noted elsewhere, the Staff takes exception to the inclusion of this assessment in regulatory assets, and therefore takes exception to their inclusion in the determination of an appropriate RTC.

F-33. Demand Side Management (DSM) Costs – FirstEnergy included DSM costs in determining its proposed RTC that reflected the unadjusted date certain balance from Case No. 95-299-EL-AIR. The Staff takes exception to this amount and recommends that the adjusted date certain amount from the last rate case be used.

F-34. Refueling Outage Accrual Balances – FirstEnergy excluded the effect of the normalization of nuclear refueling outages on Other Rate Base Items in Case No. 95-299-EL-AIR from the determination of its proposed RTC. The Staff takes exception to the exclusion of the effect of this offset, as it was a part of the determination of current rates, and therefore should be a part of the determination of an appropriate RTC.

F-35. FirstEnergy did not include the offset to Other Rate Base Items in Case No. 95-299-EL-AIR related to Davis Besse interim storage costs. The Staff takes exception to the exclusion of the effect of this offset, as it was a part of the determination of current rates, and therefore should be a part of the determination of an appropriate RTC.

F-36. FirstEnergy updated certain allocation factors in the determination of their proposed RTC. The Staff takes exception, and recommends that the Commission recognize only those jurisdictional allocation factors used in last rate case.

F-37. FirstEnergy calculated the amortization of Nuclear Safety and Radiation Control Equipment by calculating a ratio of year 2001 projected depreciation expense to projected year 2001 gross plant, and applying that ratio to date certain plant balances. The Staff takes exception to this, and recommends that the Commission determine the amortization of Nuclear Safety and Radiation Control Equipment by applying the approved depreciation accrual rates for the respective plant accounts to the date certain plant balances from Case No. 95-299-EL-AIR for the identified Nuclear Safety and Radiation Control Equipment.

F-38. The Staff takes exception to FirstEnergy's recognition of FAS 109 costs in the determination of its proposed RTC, to the extent it is affected by the above exceptions.

AAM Requests

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

F-39. Depreciation Expense Reduction - In Case No. 95-830-EL-UNC a reduction to Transmission and Distribution depreciation expense was implemented to correct an identified overaccrual in the depreciation reserve for those plant accounts. This reduction was intended to run through December 31, 2005. FirstEnergy indicates a desire to continue this reduction through the market development period. The Staff opposes this in the absence of a demonstration that the transmission and distribution overaccrual still exists, including a depreciation study of the relevant plant accounts. In addition, since this reduction was implemented as a part of the rate plan established in Case No. 95-830-EL-UNC, this request is inconsistent with FirstEnergy's request to terminate the existing rate plans.

F-40. Deferral of Ohio Gross Receipts Tax Transition - The Staff is of the opinion that deferral of this item is inappropriate, as discussed earlier.

F-41. Energy Imbalance System - The Staff is of the opinion that these deferrals are appropriate, as discussed earlier. These deferrals should be subject to a showing of material financial impact, as is discussed under each of these items in the "Identification of Regulatory Assets" section of this report

F-42. Customer Billing System Enhancement - The Staff is of the opinion that these deferrals are appropriate, as discussed earlier. These deferrals should be subject to a showing of material financial impact, as is discussed under each of these items in the "Identification of Regulatory Assets" section of this report

F-43. Electric Restructuring Consumer Education - The Staff is of the opinion that these deferrals are appropriate, as discussed earlier. These deferrals should be subject to a showing of material financial impact, as is discussed under each of these items in the "Identification of Regulatory Assets" section of this report

F-44. Electric Restructuring Employee Assistance - The Staff is of the opinion that these costs are to be recovered through transition revenues, provided that they can be documented appropriately and that they meet the criteria of exceeding the costs contemplated in labor contracts, as required by Section 4928.39(D), Revised Code.

F-45. Amortization of Transition Costs - FirstEnergy seeks regulatory approval to amortize transition costs from their regulatory books as recovery is received from ratepayers. The Staff does not oppose such an amortization, as it provides an appropriate tracking mechanism for the reviews and potential adjustments contemplated by Section 4928.40(B)(1), Revised Code.

F-46. Changes in Taxes - To the extent that FirstEnergy's requested treatment for changes in taxes is not adopted by this Commission, FirstEnergy requests authorization to defer these costs for subsequent recovery. The Staff finds it impossible to identify an exception or recommendation on this issue, due to the fact that, at this time, it is unknown what treatment will ultimately be afforded. The Staff does note, however, that the Gross Receipts Tax issue raised by FirstEnergy, as discussed above, is inappropriate for deferral.

Part G – The Applicant's 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 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

FirstEnergy plans to participate in the Alliance Regional Transmission Organization (Alliance RTO) and feels that the Alliance RTO will satisfy the requirements of a qualifying transmission entity. The company identified the nine specifications of a qualifying transmission entity as found in Section 4928.12, Revised Code and described how the Alliance RTO meets the criteria.

Staff's Exceptions and Recommendations

G-1. **Elements of the Alliance RTO -** FirstEnergy is a signatory member of the Alliance RTO as filed for approval at the Federal Energy Regulatory Commission (FERC) on June 3, 1999. On December 20, 1999, the FERC conditionally authorized the applicants to transfer ownership and/or functional control of their jurisdictional transmission facilities to the Alliance RTO. The conditional approval rejected sections of the applicant's proposal as it related to aspects of the entity's independence, governance configuration and tariff design. The Alliance RTO is currently working on the changes to the RTO structure that will address the areas of concern and deficiency that were identified in the December 20, 1999 FERC Order.

At this time the PUCO Staff is satisfied with the FERC Order in identifying deficient aspects of the Alliance RTO configuration and methods of business operation. Specifically, requiring the elimination of the proposed pancaking of rates, altering the governance structure to facilitate independence, and requiring the Alliance RTO to address other concerns regarding tariff design, if altered properly, could also satisfy the requirements laid forth in Section 4928.12, Revised Code, and the clarifying rules.

The FERC required the Alliance RTO to make changes to key aspects of its original filing. The PUCO should wait until the proposed changes are made public, evaluate the changes for compliance with Ohio statutory requirements of Ohio, then make a final ruling on the Alliance RTO as a qualifying transmission entity. Further, the Staff recommends that the PUCO convene a public meeting with all parties to the Alliance RTO that operate transmission facilities in Ohio. The meeting should be used to address the Ohio rules and how the changes to the Alliance RTO that will be taken before the FERC may also act to comply with state rules.

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. The rules were issued on November 30, 1999. On January 4, 2000, the PUCO issued an Entry on Rehearing modifying Rule 4901:1-20-17, paragraph (B)(3) allowing the three options as described above. On January 27, 2000, the Commission issued a Second Entry on Rehearing, which addressed but made no further modifications to the RTE rules. FirstEnergy filed its transition plan on December 22, 1999, before the rules modifications were finalized.

As of the date of issuance of this Staff Report, FirstEnergy has not filed an addition to its transition plan to address Rule 4901:1-20-17, paragraph (B)(3).

Staff views the Rule 4901:1-20-17, paragraph (B)(3) as an important aspect of the requirements to comply with 4928.12, Revised Code. The Commission cannot approve FirstEnergy's transition plan until the company complies with this section in a manner satisfactory to this 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), Revised Code and again in Section 4928.37, (A)(1)(b), Revised Code. 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. Those issues dealing with constraints on shopping incentives as defined by the generation component and other issues dealing with transition charges and the development of market prices for future generation services are treated in the "Transition Costs, Revenues and Charges" section of this Staff Report.

The Shopping Incentive Plan Proposed by the Applicant

The Company's Shopping Incentive Plan, listed as component 8 of its transition plan (Appendix H of the Commission Rules) is presented and supported by the direct testimonies of Eugene T. Meehan (Shopping Credits), Luann Sharp (Shopping Levels), Kurt E. Turosky (Tariff Standard Rules and Regulations and the Shopping Incentive), and David M. Blank (Unbundling and Tariffs).

As its Shopping Incentive Plan, the Applicant, through the testimony of Mr. Eugene Meehan, proposes rate schedule-specific "shopping credits" set at load-weighted market prices adjusted to reflect incremental supply costs or losses. The Applicant does not propose any incentive above their calculated shopping credits (as presented in Attachment ETM-2 of Mr. Meehan's testimony). The Applicant maintains that their "shopping credits" will be sufficient to obtain the 20% switch rate for all customer classes as mandated by Section 4928.40, Revised Code.

FirstEnergy, through the testimony of Ms. Luann Sharp, describes a process for determining the annual switching projections for each customer class and concludes that FirstEnergy's "shopping credit" plan will ensure that 20% of customer load in each class will switch to an alternative supplier. The Applicant uses data from two service territory specific customer opinion surveys, adds the likelihood of municipal aggregation, and includes a percentage of customers who are already participating in a competitive arena within FirstEnergy's service territory to develop annual projections of customer switching for the residential, commercial and industrial classes in each Company service territory.

The Applicant addresses the Commission rule requiring an Applicant to propose a specific approach to adjusting the shopping incentive after the first and second years of the market development period if the actual switching rates are lower than those projected in the transition plan by suggesting the following steps:

1. Determine the true root causes for the shopping levels being less than forecasted by examining the switching patterns and trends, to effectively identify the reasons behind actual switching levels lagging behind projected levels.

2. Adjust the recovery period for each Company's regulatory assets to create more "head room" in order to increase the shopping incentives.

3. Have the Commission permit the AFUDC associated with generation assets to be taken out of the GTC and added to the RTC, (i.e., essentially permitting AFUDC to be afforded regulatory asset treatment). That way, the recovery of AFUDC can also be spread over the remainder of the ten-year period, and "G," and hence the shopping credit, can be set higher.

4. Finally, if the 20% switching rate has not been achieved by the mid-point of the market development period, the Commission should consider terminating the 5% residential rate reduction to create more headroom and opportunity for shopping.

The Applicant, through the testimony of David Blank, notes that there are rate schedules where the generation charge is lower than the desired shopping credit and where, consequently, the shopping credit is limited by market-based "G." The Applicant goes on to suggest that the Commission should not be concerned by this fact because, since the shopping credit is constrained by “G,” it is not realistic to expect that there will be a substantial amount of customer switching in those situations

Staff’s Exceptions and Recommendations

H-1. The Staff takes exception to the fact that the Applicant has not proposed a shopping incentive as part of its transition plan filing. The Applicant has, instead, proposed "shopping credits" consisting of load-weighted, adjusted, Applicant-derived "market prices" for generation. The Applicant concludes that "there are no valid reasons to create the Incentive Transition Component as a tool for encouraging customers to choose alternative suppliers" (Meehan testimony at page 8) and that including a shopping incentive would "needlessly add inefficiencies into the marketplace" (Meehan testimony at page 9.) Staff understands Section 4928.40, Revised Code, to be a valid reason for establishing a shopping incentive 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 shopping incentives create an inefficient market and introduce inaccurate and misleading price signals in the marketplace may or may not be correct. But the entire argument is moot. The legislature specified that an incentive be considered such that 20% of the customer load of each customer class switch from the incumbent. It is implicit in the implementation of this consideration 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 requiring an incentive. The economic arguments miss the point. Switching is primary and the economic efficiency of the marketplace is secondary insofar as Chapter 4928, Revised Code is concerned.

H-2. The Staff has concerns with the Applicant's suggestion that the Commission should take a "wait and see" approach with regard to the establishment of shopping incentives. The Applicant itself recognizes the difficulty in attaining levels of residential customer switching proscribed by Section 4928.40, Revised Code. Customer switching rates in other states, as reported by the Applicant, demonstrate that to wait until the second year of the market development period to implement a shopping incentive would handicap the potential for switching by more than a third of the time that has been designated for 20% of the target to be reached.

H-3. The Applicant states that "(e)ffective competition cannot be measured by the number of customers who switch suppliers." It is the Staff's perspective that measures of competition involve, at least in the input stage, the measurement of the number of customers who switch from an incumbent. It is axiomatic that unless customers switch suppliers, there is no effective competition.

H-4. 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. While the Applicant has provided evidence of service territory specific customer surveys of switching behaviors, they have not responded to subsequent data requests with complete copies of all survey materials. Thus, without complete information, the Staff is unable to verify that the information from the surveys is accurate or a reasonable basis upon which the Applicant should formulate its projected customer switching behavior.

In addition, the Applicant witness Sharp'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 her projections of annual switching levels will be attained with any degree of certainty. The approach might result in accurate projections or it might not. There is no systematic and reasonable approach which underlies the connection of the initial assumptions made by Ms. Sharp with the specific numbers which are included in her formula for determining switching projections.

H-5. The Staff takes exception to the Applicant using customers who have already chosen other suppliers as part of their projections for attaining 20% levels by the target date. It is Staff's recommendation that counting customers who switch suppliers begins on the start date of the market development period, January 1, 2001, and that customers who have changed supplier prior to that date are not to be part of the baseline load used to calculate switching percentages. It is Staff's interpretation of Chapter 4928, Revised Code, that switching behavior is to be caused by the practices that are part of the Applicant's transition plans and which are to be implemented at the onset of the market development period once the plans are approved by the Commission.

H-6. The Staff is concerned that, due to its interpretation of the application of industrial customer special contracts throughout the term of the contract, the Applicant will be unable to attain the 20% switching level of the industrial customer class of certain of its Companies in the proscribed time period. The Staff recommends that the Applicant count all industrial customers served by special contract as part of the industrial class, and that the measurement of the 20% switch rate be done against a customer class that includes such special contract customers. In order to achieve the 20% switch rate, the Applicant may wish to provide a "fresh look" for industrial customers under contract to allow them to benefit from shopping for a generation supplier as well as to more surely enable the Applicant to attain 20% switching in the industrial customer class per Chapter 4928, Revised Code.

H-7. The Applicant proposes to offer a greater level of assistance to government entities in their efforts to become effective aggregators only if shopping levels do not approach projections. The Staff recommends that the Applicant might be more able to demonstrate its likelihood of reaching the 20% switching levels in the residential and commercial customer classes if it proposed to encourage and assist local government aggregation at the onset of the market development period rather than after a "wait and see" period.

H-8. The Applicant proposes to make adjustments in out-years to the shopping incentive by reclassifying AFUDC as a regulatory asset, and thereby extend the period in which it may be recovered (see Testimony of Kurt Turosky at page 13.) This, in turn, it is argued, would provide greater "headroom" to increase the shopping incentive. Staff takes exception to this approach. AFUDC is not among the items identified by Chapter 4928, Revised Code, as regulatory assets. AFUDC does not meet any of the criteria outlined in Chapter 4928, Revised Code, for recovery through the regulatory asset revenue stream. The appropriate relationship between shopping incentives and transition revenues is discussed in the "Transition Costs, Revenues and Charges" section of this Staff Report.

H-9. The Applicant suggests that if actual switching rates are lower than those projected in the transition plan, the "true root causes for the shopping levels being less than forecasted" need to be researched and identified. The Staff concurs that it is incumbent on the Applicant to ascertain the effect of its transition plan and shopping incentive proposals on levels of customer switching. Staff recommends that the Applicant propose a formal research project to track customer switching throughout the market development period and to review causes for both customers switching suppliers and remaining with the Applicant.

H-10. 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 "wait and see" approach will accomplish the customer switching goals that are clearly defined by Chapter 4928, Revised Code.

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:**

FirstEnergy’s proposed plan for transmission requirements is described in direct testimony by Applicant witness Ronald I. Green, who states,

> The Utility Companies will continue to arrange for and meet transmission requirements for customers who elect to receive standard tariff offer service from the utility companies. It should be noted that Certified Suppliers will be responsible for arranging for their own transmission services." *Testimony* at 17.

There is a finite amount of transmission capacity in Ohio, which is more scarce during peak periods. Staff notes the FirstEnergy System Open Access Transmission Tariff (FE OATT) states that network integration transmission service from network resources designated by a network customer to serve network loads is to be "provided on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers." (FE OATT at 85). To insure comparability, the transmission provider is to "designate resources and loads in the same manner as any Network Customer." *Id.*

Staff's Exception and Recommendation

Staff takes exception to the failure of the Applicant's proposed plan to address how transmission capacity calculated on behalf of retail standard offer 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 electric utility subsidiaries'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 customers." Not to do so, discriminates against the consumers 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

A potential problem may exist, however, when retail customers' requirements for transmission facilities change due to change in sources of supply. Under competitive retail electric service, network delivery from FirstEnergy generation to the customer's load may be replaced by network delivery from resources outside the network to the customers' load. For that reason, Staff recommends the activation of the Network Operating Committee described in Section 35.3 of the FE 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.[5]

[5] The stated purpose of the Network Operating Committee is to coordinate operating criteria for the Parties respective responsibilities under the Network Operating Agreement. The Network Operating Agreement for the

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 23.1 of the FE OATT.

Meeting the Requirements of Governmental Aggregators

FirstEnergy's proposed plan is stated in direct testimony by Applicant Witness Green, who promises,

> The Utility Companies will work with governmental aggregators to assist those authorities in understanding the overall aggregator requirements and what steps will be required to meet such requirements. As part of this effort, the Company may provide information specific to governmental aggregation at its websites and in material that will be developed for this purpose. Based upon the level of interest, we will also consider holding workshops for governmental aggregators to explain the aggregation requirements and processes and will work one-on-one with governmental aggregators as interest in this process and any applicable guidelines develop. Witness Green, *Testimony* at 17.

Each of the Applicant's electric utility subsidiary's unbundled tariff Standard Rules and Regulations mention that any customer may be represented by an aggregator. In addition, "no charge of a tariffed service will be affected by a customer's aggregation status." Cleveland Electric Illuminating (CEI) UNB-1 at 27; Ohio Edison (OE) UNB-1 at 29; Toledo Edison (TE) UNB-1 at 26.

Certain tariff policies and amendments to tariff language proposed by the Applicant, however, contradict both the Applicant's intention stated by Witness Green as well as the Applicants Standards Rules and Regulations. These contradictions will have a particularly negative affect on 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, until a person so enrolled affirmatively elects by a stated procedure not to remain so enrolled, in accordance with Section 4928.20 (D), Revised Code.

Ohio retail market is prescribed in Attachment O, "Operating Agreement for Network Integration Transmission Service Customers Under the Ohio Retail Electric Program." The FE OATT further states that each Network Customer is entitled to have at least one representative on the FirstEnergy Network Operating Committee, which is to meet from time to time as need requires. FE OATT at 113.

Staff's Exceptions and Recommendations

Staff takes exception to Applicant's proposed tariff policies that create undue burdens on competitive retail electric service undertaken through automatic enrollment in governmental aggregation programs. Language amendments to tariff terms and conditions create the potential for confusion among customers subject to automatic enrollment under government aggregation programs by tying them to a full service provision that is different from, or incompatible with the tariff provisions of the service selected by the government aggregator.[6] The potential impediments to which Staff takes exception Staff's recommended solution is that the Application should, in its service territory specific portion of the Consumer Education campaign, provide information on how to resolve the confusions identified below, to both governmental aggregators and customers under their automatic enrollment programs, who are now taking service under the tariffs identified below:

I-2. Applications and Contracts

Provisions for new installation, re-establishment of service, or change in the identity of the customer (CEI UNB-1 at 8; OE UNB-1 at 7; TE UNB-1 at 4) should include explicit language to address administrative coordination with the governmental aggregator for such installments and changes in geographic areas subject to automatic enrollment under Section 4928.20 (D), Revised Code. Not to do so, may result in service disruptions and other reliability problems for the Applicant's control area as well as create potential structural impediments to effective service delivery in the governmental aggregation program.

I-3. Changing Electric Suppliers

Applicant's requirement for an "ink-signed explicit customer designation of a Certified Supplier…for a minimum time period of one month." (CEI UNB-1 at 22; OE UNB-1 at 23; TE UNB-1 at 21) is in direct conflict with the intent of 4928.20 (D) to allow automatic enrollment by a governmental aggregator. This requirement should be waived for automatic enrollment and replaced by a more efficient administrative arrangement between the governmental aggregation program and the Applicant.

I-4. Switching Fees

Witness Green states that because of the administrative costs of switching, a switching fee will be charged to the new Certified Supplier each time a switch occurs. *Testimony* at 8. Staff recommends establishment of an least-cost administrative process for switching customers *en masse*, regardless of individual customer load, for the geographic area of the political subdivision that adopts automatic enrollment pursuant to the provisions of Section 4928.20 (D), Revised Code in order to avoid a structural impediment to this type of aggregation.

[6] A Full Service Customer is one that receive all retail electric services from the Applicant. CEI UNB-1 at 23; OE UNB-1 at 24; TE UNB-1 at 22).

I-5. Return to Standard Offer Supply

Applicant requires (CEI UNB-1 at 23; OE UNB-1 at 24; TE UNB-1 at 22) a customer returning to the Applicant's generation service must sign a written contract for Full Service from the Applicant for a period not less than 12 consecutive months, unless a longer service period applies. Tying return to the Applicant's Standard Offer to such Full Service arrangements is in direct contradiction with the opt-out provision of Section 4928.20 (D), Revised Code for automatic enrollment.[7] The Full Service language amendment should be replaced by a provision that balances Applicant's planning requirements with the opportunities for selection of an alternative supplier anticipated by the opt-out provision in Section 4928.20 (D), Revised Code.

I-6 Other Tariff Amendments Requiring Full Service from the Applicant

The Applicant also proposes Full Service requirement language amendments to tariffs, particularly those applying to higher load customers, which can result in potential structural impediments to automatic enrollment in governmental aggregation programs under Section 4928.20 (D), Revised Code. Examples of tariffs with such amendments and Staff's recommended solutions to the potential structural impediments they create are as follows:

I-6.1. Electrically-Heated Residential Apartment tariffs for complexes of not less than four apartments (CEI UNB-1 at 59-63; TE UNB-1 at 64-67 and 68-72) requires Full Service from the Applicant's electric utility subsidiaries. Tying this service to Full Service from CEI or TE has the potential to confuse customers taking service under this tariff who are automatically enrolled in governmental aggregation programs. By contrast, the OE tariff (UNB-1 at 62-66) for the same type of service allows generation services from Certified Suppliers and a Shopping Credit.

I-6.2. Electric Space Conditioning, heating and air conditioning for other than single family homes (CEI UNB-1 at 72-74; TE UNB-1 at 112-114) is amended to tie this service to Full Service from the Applicant's electric utility subsidiaries. This language amendment has the potential to confuse customers taking service under this tariff who are automatically enrolled in governmental aggregation programs.

I-6.3. Controlled Water Heating and Heat Pump submetering provisions in a Residential Space Heating Rate for non-electric space heating, that otherwise allows generation services from a Certified Supplier and qualification for a Shopping Credit, is tied to Full Service from Ohio Edison by language amendments (OE UNB-1 at 45-47). Such language amendments have the potential to confuse customers taking service under these specific provisions who are automatically enrolled in governmental aggregation programs.

[7] Section 4928.20(D) provides "any person enrolled in the [automatic enrollment] aggregation program the opportunity to opt-out of the program every two years, without paying a switching fee…[and] default to the standard service offer provided under division (A) of section 4928.14 or division (D) of section 4928.35 of the Revised Code until the person chooses an alternative supplier."

I-6.4. Time-of-Day metering for each family unit in a multifamily residence or apartment, including condominiums, is amended to tie this service to Full Service from Ohio Edison (OE UNB-1 at 49), thus having the potential to confuse customers now taking time-of-day metering service who are automatically enrolled in a government aggregation program.

I-6.5. Secondary Voltage Metering General Service tariff, that otherwise allows generation services from a Certified Supplier and qualification for a Shopping Credit, has the potential to confuse customers who are provided on-peak and off-peak demand metering.(OE UNB-1 at 69). Language amendments to certain provisions in this tariff tie such demand metering to Full Service by the Applicant's electric utility subsidiaries. Among those customers to whom this provision can apply are non-profit governmental and educational institutions and like customers with outdoor recreational facilities, who are automatically enrolled in governmental aggregation pursuant to Section 4928.20 (D), Revised Code.

I-6.6. Large School Rate, which otherwise allows generation services from a Certified Supplier and qualification for a Shopping Credit, contains proposed language amendments tying off-peak metering and monthly billing demand to Full Service generation from Toledo Edison (TE UNB-1 at 86 – 88.) In addition, the tariff language has been amended to require a five-year contract with the Applicant. The continued availability of a transformer discount for transformers for customer who have installed their own transformers but are automatically enrolled in a government aggregation programs is also unclear. The length of term for a large school contract is also not in conformance with the opt-out provisions of Section 4928.20 (D), Revised Code.

I-6.7. Controlled Water Heating (TE UNB-1 at 128-129) for service at secondary voltages, water heating, electric water heaters or as a supplemental source for solar heating systems has been amended to tie these services to Full Service from Toledo Edison. These language amendments have the potential to confuse customers currently receiving this service who are automatically enrolled in a governmental aggregation program.