LARGE FILING SEPARATOR SHEET

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D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. The set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by

agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

Effective Date: 5/15/2012 - Docket #: ER11-4628-000

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any auction under Attachment DD of the PJM Tariff for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any Capacity Resource that has not cleared such an auction for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Attachment DD of the PJM Tariff for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to Section B.2 of this Schedule that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party's expected Daily Unforced Capacity Obligation under Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party's total expected Unforced Capacity obligation (under both Schedule 8 and Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions).

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

5. The shortages in meeting the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation are calculated separately. The applicable penalty rate is calculated for Annual Resources, Extended Summer Demand Resources, and Limited Resources as (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions).

Effective Date: 5/15/2012 - Docket #: ER11-4628-000

G. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in sections 7, 9, 10, 11, and 13 of Attachment DD to the PJM Tariff; provided, however, the Daily Deficiency Rate under sections 7, 9, and 13 thereof shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions), and the charge rates under section 10 thereof, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7, 9, and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

H. Annexation of service territory by Public Power Entity

1. In the event a Public Power Entity that is an FRR Entity annexes service territory to include new customers on sites where no load had previously existed, then the incremental load on such a site shall be treated as unanticipated load growth, and such FRR Entity shall be required to commit sufficient resources to cover such obligation in the relevant Delivery Year.

2. In the event a Public Power Entity that is an FRR Entity annexes service territory to include load from a Party that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, such acquiring FRR Entity shall meet its obligations for the incremental load by paying PJM for incremental obligations (including any additional demand curve obligation) at the Capacity Resource Clearing Price for the relevant location. Any such revenues shall be used to pay Capacity Resources that cleared in the BRA for that LDA.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

3. Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR entity:

a. For any Delivery Year for which a Base Residual Auction already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining whether to hold a Second Incremental Auction. If a Second Incremental Auction is held, FRR entity would have a must offer requirement for sufficient capacity to meet the load obligation of such shifted load. If no Second Incremental Auction is conducted, the FRR Entity may sell the associated quantity of capacity into an RPM Auction or bilaterally.

b. For any Delivery Year for which a Base Residual Auction has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include such shifted load in future BRAs.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

I. Savings Clause for State-Wide FRR Program

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and El05-148, the PJM Tariff and this Agreement. Each LSE subject to such state action shall become a Party to this Agreement and shall be deemed to have elected the FRR Alternative.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

SCHEDULE 9

PROCEDURES FOR
ESTABLISHING THE CAPABILITY OF GENERATION CAPACITY RESOURCES

A. Such rules and procedures as may be required to determine and demonstrate the capability of Generation Capacity Resources for the purposes of meeting a Load Serving Entity's obligations under the Agreement shall be developed by the Office of Interconnection and maintained in the PJM Manuals.

B. The rules and procedures for determining and demonstrating the capability of generating units to serve load in the PJM Region shall be consistent with achieving uniformity for planning, operating, accounting and reporting purposes.

C. The rules and procedures shall recognize the difference in types of generating units and the relative ability of units to maintain output at stated capability over a specified period of time. Factors affecting such ability include, but are not limited to, fuel availability, stream flow for hydro units, reservoir storage for hydro and pumped storage units, mechanical limitations, and system operating policies.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 10

PROCEDURES FOR ESTABLISHING DELIVERABILITY OF GENERATION CAPACITY RESOURCES

Generation Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Region that may have a capacity deficiency at any time. Deliverability shall be demonstrated by either obtaining or providing for Network Transmission Service or Firm Point-To-Point Transmission Service within the PJM Region such that each Generation Capacity Resource is either a Network Resource or a Point of Receipt, respectively. In addition, for Generation Capacity Resources located outside the metered boundaries of the PJM Region that are used to meet an Unforced Capacity Obligation, the capacity and energy of such Generation Capacity Resources must be delivered to the metered boundaries of the PJM Region through firm transmission service.

Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide that service consistent with the assessment of available transfer capability as set forth in the PJM Tariff and, for Generation Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained or provided for Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

- ATSI
- DEOK
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Region (MAR) (consisting of all the zones listed below for Eastern MAR (EMAR), Western MAR (WMAR), and Southwestern MAR (SWMAR))
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, and DEOK
- EMAR (PSE&G, JCP&L, PECO, AE, DPL & RE)
- SWMAR (PEPCO & BG&E)
- WMAR (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 12

DATA SUBMISSION CHARGES

A. Data Submission Charge

For each working day of delay in the submittal of information required to be submitted under this Agreement, a data submission charge of $500 shall be imposed.

B. Distribution Of Data Submission Charge Receipts

1. Each Party that has satisfied its obligations for data submittals pursuant to Schedule 11 during a Delivery Year, without incurring a data submission charge related to that obligation, shall share in any data submission charges paid by any other Party that has failed to satisfy said obligation during such Planning Period. Such shares shall be in proportion to the sum of the Unforced Capacity Obligations of each such Party entitled to share in the data submission charges for the most recent month.

2. In the event all of the Parties have incurred a data submission charge during a Delivery Year, those data submission charges shall be distributed as approved by the PJM Board.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

   (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

   (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

   (a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

   (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

   (c) Monitor the compliance of each Party with its obligations under the Agreement;

   (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

   (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

   (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Entity principles, guidelines, standards, requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

Effective Date: 7/18/2012 - Docket #: ER12-1784-000

SCHEDULE 15
ZONES WITHIN THE PJM REGION

FULL NAME	SHORT NAME
Pennsylvania Electric Company	Penelec
Allegheny Power	APS
PPL Group	PPL
Metropolitan Edison Company	MetEd
Jersey Central Power and Light Company	JCPL
Public Service Electric and Gas Company	PSEG
Atlantic City Electric Company	AEC
PECO Energy Company	PECO
Baltimore Gas and Electric Company	BGE
Delmarva Power and Light Company	DPL
Potomac Electric Power Company	PEPCO
Rockland Electric Company	RE
Commonwealth Edison Company	ComEd
AEP East Zone	AEP
The Dayton Power and Light Company	Dayton
Virginia Electric and Power Company	Dominion
Duquesne Light Company	DL
American Transmission Systems, Incorporated	ATSI
Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.	DEOK

SCHEDULE 16

Non-Retail Behind the Meter Generation Maximum Generation Emergency Obligations

1. A Non-Retail Behind The Meter Generation resource that has output that is netted from the Daily Unforced Capacity Obligation of a Party pursuant to Schedule 7 of this Agreement shall be required to operate at its full output during the first ten times between November 1 and October 31 that Maximum Generation Emergency (as defined in section 1.3.13 of Schedule 1 of the Operating Agreement) conditions occur in the zone in which the Non-Retail Behind The Meter Generation resource is located.

2. The Party for which Non-Retail Behind The Meter Generation output is netted from its Daily Unforced Capacity Obligation shall be required to report to PJM scheduled outages of the resource prior to the occurrence of such outage in accordance with the time requirements and procedures set forth in the PJM Manuals. Such Party also shall report to PJM the output of the Non-Retail Behind The Meter Generation resource during each Maximum Generation Emergency condition in which the resource is required to operate in accordance with the procedures set forth in PJM Manuals.

3. Except for failures to operate due to scheduled outages during the months of October through May, for each instance a Non-Retail Behind The Meter Generation resource fails to operate, in whole or in part, as required in paragraph 1 above, the amount of operating Non-Retail Behind The Meter Generation from such resource that is eligible for netting will be reduced pursuant to the following formula:

$$\text{Adjusted ENRBTMG} = \text{ENRBTMG} - \sum (10\% \text{ of the Not Run NRBTMG})$$

Where:

ENRBTMG equals the operating Non-Retail Behind The Meter Generation eligible for netting as determined pursuant to Schedule 7 of this Agreement.

Not Run NRBTMG is the amount in megawatts that the Non-Retail Behind The Meter Generation resource failed to produce during an occurrence of Maximum Generation Emergency conditions in which the resource was required to operate.

$\sum$ (10% of the Not Run NRBTMG) is the summation of 10% megawatt reductions associated with the events of non-performance.

The Adjusted ENRBTMG shall not be less than zero and shall be applicable for the succeeding Planning Period.

4. If a Non-Retail Behind The Meter Generation resource that is required to operate during a Maximum Generation Emergency condition is an Energy Resource and injects energy into the

Transmission System during the Maximum Generation Emergency condition, the Network Customer that owns the resource shall be compensated for such injected energy in accordance with the PJM market rules.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 17

PARTIES TO THE RELIABILITY ASSURANCE AGREEMENT

This Schedule sets forth the Parties to the Agreement:

AEP Retail Energy Partners LLC
AES Red Oak, LLC
Algonquin Energy Services Inc.
Allegheny Electric Cooperative, Inc.
Allegheny Energy Supply Company, L.L.C.
Alpha Gas and Electric LLC
Ambit Northeast, LLC
Ameren Energy Marketing Company
American Electric Power Service Corporation on behalf of its affiliates:
    Appalachian Power Company
    Indiana Michigan Power Company
    Kentucky Power Company
    Kingsport Power Company
    Ohio Power Company
    Wheeling Power Company.
American Municipal Power, Inc.
American Power Partners LLC
American PowerNet Management, L.P.
American Transmission Systems, Inc.
AP Gas and Electric (PA), LLC
APN Starfirst, LP
ArcelorMittal USA LLC
Atlantic City Electric Company
Baltimore Gas and Electric Company
Bank of America, N.A.
Barclays Bank PLC
Barclays Capital Services, Inc
Bativa, IL (City of)
BBPC LLC d/b/a Great Eastern Energy
Blackstone Wind Farm, LLC
Blue Ridge Power Agency, Inc.
Blue Star Energy Services, Inc.
Border Energy Electric Services, Inc.
Borough of Butler, Butler Electric Division
Borough of Chambersburg
Borough of Lavallette, New Jersey
Borough of Milltown
Borough of Mont Alto, PA
Borough of Park Ridge, New Jersey
Borough of Pemberton

Borough of Pitcairn, Pennsylvania
Borough of Seaside Heights, New Jersey
Borough of South River, New Jersey
BP Energy Company
Brighten Energy LLC
Cargill Power Markets LLC
Castlebridge Energy Group, LLC
CCES LLC
Central Virginia Electric Cooperative
Centre Lane Trading Limited
Champion Energy Marketing LLC
Champion Energy, LLC
Cincinnati Bell Energy, LLC
Citizens' Electric Company of Lewisburg, PA
City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
City of Dover, Delaware
City of Naperville
City of New Martinsville - WV
City of Philippi - West VA
City of Rochelle
Clearview Electric, Inc.
Cleveland Electric Illuminating Company (The)
Commerce Energy, Inc.
Commonwealth Edison Company
Conectiv Energy Supply, Inc.
ConEdison Energy, Inc.
ConocoPhillips Company
Consolidated Edison Solutions, Inc.
Constellation Energy Commodities Group, Inc.
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Corporate Services Support Corp
Credit Suisse (USA), Inc.
Dayton Power & Light Company (The)
DC Energy LLC
Delaware Municipal Electric Corporation
Delmarva Power & Light Company
Denver Energy, LLC
Devonshire Energy LLC
Direct Energy Business, LLC
Direct Energy Services, LLC
Discount Energy Group, LLC
Discount Energy, LLC
Dominion Retail, Inc.
Downes Associates, Inc.
DPL Energy Resources, Inc.

DTE Energy Supply, Inc.
DTE Energy Trading, Inc.
Duke Energy Commercial Asset Management, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duke Energy Retail Sales, LLC
Duquesne Light Company
Duquesne Light Energy, LLC
Dynegy Energy Services, Inc.
Dynegy Kendall Energy, LLC
Eagle Energy, LLC
Easton Utilities Commission
EDF Industrial Power Services (IL), LLC
EDF Trading North America, LLC
Edison Mission Marketing and Trading, Inc.
Employers' Energy Alliance of Pennsylvania, Inc.
Energetix, Inc.
Energy America, LLC
Energy Cooperative Association of Pennsylvania (The)
Energy Cooperative of America, Inc.
Energy International Power Marketing Corporation
Energy Plus Holdings LLC
Energy Services Providers, Inc.
EnerPenn USA, LLC
ERA MA, LLC
Evraz Claymont Steel
Exelon Energy Company
Exelon Generation Co., LLC
FirstEnergy Solutions Corp.
First Point Power, LLC
Front Royal (Town of)
Galt Power Inc.
Gateway Energy Services Corporation
GenOn Power Midwest, LP
Gerdau Ameristeel Energy, Inc.
GDF Suez Retail Energy Solutions, LLC
Glacial Energy of New Jersey, Inc.
Great American Power, LLC
Green Mountain Energy Company
Hagerstown Light Department
Harrison REA, Inc. - Clarksburg, WV
Hess Corporation
HIKO Energy, LLC
Hoosier Energy REC, Inc.
HOP Energy, LLC
HSBC Technology & Services (USA), Inc.

Hudson Energy Services, LLC
IDT Energy, Inc.
Illinois Municipal Electric Agency
J. Aron & Company
J.P. Morgan Ventures Energy Corporation
Jack Rich, Inc. d/b/a Anthracite Power & Light Company
Jersey Central Power & Light Company
Kuehne Chemical Company, Inc.
L & P Electric Inc., d/b/a Leggett & Platt Electric Inc.
Liberty Power Corp., L.L.C.
Liberty Power Delaware LLC
Liberty Power Holdings LLC
Linde Energy Services, Inc.
Lower Electric, LLC
Macquarie Cook Energy LLC
Major Energy Electric Services LLC
Manitou Energy Fund, LP
Marathon Power, LLC
MC Squared Energy Services, LLC
Meadow Lake Wind Farm II LLC
Meadow Lake Wind Farm III LLC
Meadow Lake Wind Farm IV LLC
Meadow Lake Wind Farm LLC
MeadWestvaco Corporation
Metropolitan Edison Company
MidAmerican Energy Company
Mint Energy, LLC
Morgan Stanley Capital Group, Inc.
MP2 Energy NE, LLC
MXenergy Electric, Inc.
Natgasco, Inc.
Nextera Energy Services New Jersey, LLC
Nextera Energy Services, Illinois, LLC
Noble Americas Energy Solutions LLC
Noble Americas Gas & Power Corp.
Nordic Energy Services LLC
North American Power and Gas LLC.
North Carolina Electric Membership Corporation
North Carolina Municipal Power Agency Number 1
Northern Virginia Electric Cooperative – NOVEC
Northeastern REMC
NRG Power Marketing, L.L.C.
NYSEG Solutions, Inc.
Oasis Power, LLC dba Oasis Energy
Occidental Power Services, Inc.
Ohio Edison Company

Ohms Energy Company, LLC
Old Dominion Electric Cooperative
Palmco Power DC, LLC
Palmco Power IL, LLC
Palmco Power MD, LLC
Palmco Power NJ, LLC
Palmco Power OH, LLC
Palmco Power PA, LLC
Panda Power Corporation
Parma Energy, LLC
PBF Power Marketing LLC
PECO Energy Company
Pennsylvania Electric Company
Pennsylvania Power Company
People's Power & Gas, LLC
PEPCO Energy Services, Inc.
Planet Energy (Maryland) Corp.
Planet Energy (Pennsylvania) Corp.
Planet Energy (USA) Corp.
Plymouth Rock Energy, LLC
Potomac Electric Power Company
PPL Electric Utilities Corporation d/b/a PPL Utilities
PPL Energy Plus, LLC
Prairieland Energy, Inc.
PSEG Energy Resources and Trade LLC
Public Power, LLC
Public Service Electric & Gas Company
Realgy, LLC
ResCom Energy, LLC
Respond Power LLC
RG Steel Sparrows Point, LLC
Riverside Generating, LLC
Rolling Hills Generating, LLC
S.J. Energy Partners, Inc.
Santanna Energy Services
SMART Papers Holdings, LLC
Solios Power Mid-Atlantic Trading LLC
South Jersey Energy Company
South Jersey Energy Solutions, L.L.C.
Southeastern Power Administration
Southern Indiana Gas & Electric
Southern Maryland Electric Cooperative, Inc.
Spark Energy, L.P.
Sperian Energy Corp
Starion Energy PA Inc.
Stream Energy Columbia, LLC

Stream Energy Maryland, LLC
Stream Energy Pennsylvania, LLC
Superior Plus Energy Services Inc.
Sustainable Star, LLC
TC Energy Trading, LLC
Tenaska Power Services Co.
TERM Power & Gas, LLC
Texas Retail Energy, LLC
The Trustees of the University of Pennsylvania
Thurmont Municipal Light Company
Toledo Edison Company (The)
Town of Berlin, Maryland
Town of Williamsport
TransAlta Energy Marketing (U.S.) Inc.
TransCanada Power Marketing Ltd.
Tri-County Rural Electric Cooperative, Inc.
TriEagle Energy, LP
Trinity Powerworks, Inc.
U.S. Energy Partners dba PAETEC Energy Marketing
UBS AG, acting through its London Branch
UGI Energy Services, Inc.
UGI Utilities, Inc. - Electric Division
Valero Power Marketing, LLC
VCharge, Inc.
Verde Energy USA, Inc.
Verde Energy USA Illinois, LLC
Verde Energy USA Ohio, LLC
Vineland Municipal Electric Utility (City of Vineland)
Virginia Electric & Power Company
Viridian Energy PA LLC
Wabash Valley Power Association, Inc.
Washington Gas Energy Services, Inc.
Wellsboro Electric Company
West Penn Power Company d/b/a Allegheny Power
Xoom Energy, LLC
Xoom Energy Maryland, LLC
Xoom Energy New Jersey, LLC
York Generation Company, LLC

Effective Date: 3/31/2012 - Docket #: ER12-1595-000

SUMMARY OF
THE COMMISSION'S OPINION AND ORDER OF SEPTEMBER 28, 2000
IN THE COLUMBUS SOUTHERN POWER COMPANY AND OHIO POWER COMPANY
ELECTRIC TRANSITION PLAN CASES
CASE NOS. 99-1729-EL-ETP AND 99-1730-EL-ETP

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (SB 3) on July 6, 1999, and most provisions of SB 3 became effective on October 5, 1999. Section 4928.31, Revised Code, requires each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in the state of Ohio.

On December 30, 1999, Columbus Southern Power Company and Ohio Power Company (hereinafter jointly referred to as "AEP") filed transition plans, as well as requests for receipt of transition revenues. On May 8, 2000, a stipulation and recommendation on AEP's transition plans, was filed on behalf of the following 23 parties:

AEP,
Appalachian People's Action Coalition,
Association for Hospitals and Health Systems, also d/b/a the
Ohio Hospital Association,
Buckeye Power, Inc.,
Columbia Energy Services Corporation,
Columbia Energy Power Marketing Corporation,
Enron Energy Services, Inc.,
Industrial Energy Users-Ohio,
The Kroger Company,
Mid-Atlantic Power Supply Association,
National Energy Marketers Association,
NewEnergy Midwest, LLC,
Ohio Consumers' Counsel,
Ohio Council of Retail Merchants,
Ohio Department of Development,
Ohio Manufacturers' Association,
Ohio Partners for Affordable Energy,
Ohio Rural Electric Cooperatives, Inc.,
Peco Energy Company, d/b/a Exelon Energy,
Public Utilities Commission staff,
Strategic Energy L.L.P.,
WPS Energy Services, Inc., and
WSOS Community Action Commission, Inc.

Dynegy, Inc. and Ohio Environmental Council have stated that they do not oppose the May 8, 2000 stipulation. The evidentiary hearings were held on May 9, 31, and June 7, 8, and 12, 2000. Local public hearings were held on June 5, 2000, in East Liverpool, Ohio and on June 22,2000, in Columbus, Ohio. On June 19, 2000, AEP and Ameritech New Media, Inc. filed a stipulation to resolve their differences.

In the opinion and order, the Commission is approving the agreements submitted by the various parties listed above with certain modifications regarding the load shaping service, the operational support plan, and the employee assistance plan. The Commission defers a ruling upon the independent transmission plan, as allowed by Section 4928.34(A)(13), Revised Code. The Commission found that the terms of the agreements, considered in their totality, advance the public interest and provides substantial benefits to all customer classes. The stipulations provide for extended rate freezes, flexibility for larger contract customers not otherwise available, and defined transition periods for AEP. The stipulations, among other things:

(1) Provide a five-percent reduction of AEP's generation component for residential rate schedules;
(2) Create shopping credits that facilitate the development of the retail marketplace;
(3) Commit AEP to absorb certain costs associated with transitioning to a competitive marketplace;
(4) Commit AEP to provide certain types of assistance to transmission users for a period of time;
(5) Commit AEP to provide funds (up to $10 million) for reimbursement of certain transmission costs of suppliers and customers;
(6) Commit AEP to develop and propose resolutions of reciprocity and interface/seams issues;
(7) Provide a credit to suppliers for consolidated billing; and
(8) Provide relief from certain charges for certain customers that switch suppliers between 2006 and 2007.

The Commission also determined that AEP's transition plan filings, as amended by the settlement agreements and subject to the conclusions in the decision, are in compliance with the statutory requirements contained in SB 3. By approving the stipulations as set forth in this decision, the Commission also authorizes certain accounting treatments for AEP to create the necessary regulatory assets, defer costs, and recover those costs through a regulatory transition charge.

This summary was prepared to provide a brief statement of the Commission's action in these cases. It is not part of the Commission's decision and does not supersede the full text of the Commission's opinion and order.

TABLE OF CONTENTS

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues.	)))))	Case Nos. 99-1729-EL-ETP 99-1730-EL-ETP

OPINION AND ORDER

The Commission, coming now to consider the stipulations, testimony, and other evidence presented in these proceedings, hereby issues its Opinion and Order.

APPEARANCES:

Marvin I. Resnick, Edward J. Brady, and Kevin F. Duffy, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, and Porter, Wright, Morris & Arthur, LLP, by Daniel R. Conway and Mary Kay Fenlon, 41 South High Street, Columbus, Ohio 43215-6194, on behalf of Columbus Southern Power Company and Ohio Power Company.

Betty D. Montgomery, Attorney General of the State of Ohio, by Duane W. Luckey, Section Chief, and Thomas W. McNamee and Stephen A. Reilly, Assistant Attorneys General, Public Utilities Section, 180 East Broad Street, 9th Floor, Columbus, Ohio 43215-3793, on behalf of the staff of the Public Utilities Commission of Ohio.

Betty D. Montgomery, Attorney General of the State of Ohio, by Jodi M. Elsass-Locker, Assistant Attorney General, 77 South High Street, 29th Floor, Columbus, Ohio 43215, and Maureen R. Grady, 369 South Roosevelt Avenue, Columbus, Ohio 43209, on behalf of the Ohio Department of Development.

Robert S. Tongren, Ohio Consumers' Counsel, and Colleen L. Mooney, Terry L. Etter, Ann M. Hotz, and Dirken D. Winkler, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215-3485, on behalf of the residential customers of Columbus Southern Power Company and Ohio Power Company.

McNees, Wallace & Nurick, by Samuel C. Randazzo, Gretchen J. Hummel, and Kimberly J. Wile, Fifth Third Center, 21 East State Street, Suite 1700, Columbus, Ohio 43215-4228, on behalf of Industrial Energy Users-Ohio.

Boehm, Kurtz & Lowry, by Michael L. Kurtz, 2110 CBLD Center, 36 East Seventh Street, Cincinnati, Ohio 45202, on behalf of The Kroger Company.

Chester, Willcox & Saxbe LLP, by John W. Bentine and Jeffrey L. Small, 17 South High Street, Suite 900, Columbus, Ohio 43215, and William T. Zigli and Ivan L. Henderson, 601 Lakeside Avenue, Room 106, Cleveland, Ohio 44114, and Climaco, Lefkowitz, Peca, Wilcox & Garfoli Co. LPA, by Anthony J. Garfoli, Joe Hegedus, and Scott Simpkins, on behalf of the city of Cleveland.

Chester, Willcox & Saxbe LLP, by John W. Bentine and Jeffrey L. Small, 17 South High Street, Suite 900, Columbus, Ohio 43215, on behalf of the Ohio Council of Retail Merchants and American Municipal Power-Ohio, Inc.

Craig G. Goodman, 3333 K Street, NW, Suite 425, Washington D.C. 20007, on behalf of The National Energy Marketers Association.

Calfee, Halter & Griswold LLP, by Kevin M. Sullivan, Richard J. Mattera, and Peter A. Rosato, 1400 McDonald Investment Center, 800 Superior Avenue, Cleveland, Ohio 44114, on behalf of Ameritech New Media, Inc.

William M. Ondrey Gruber, 2714 Leighton Road, Shaker Heights, Ohio 44120, and Vicki L. Deisner, 1207 Grandview Avenue, Room 201, Columbus, Ohio 43212-3449, on behalf of Ohio Environmental Council.

David C. Rinebolt, 337 South Main Street, 4th Floor, Suite 5, Findlay, Ohio 45840, on behalf of Ohio Partners for Affordable Energy.

Ohio State Legal Services Association, by Michael R. Smalz, 861 North High Street, Columbus, Ohio 43215, on behalf of the Appalachian People's Action Coalition.

Ellis Jacobs, 333 West First Street, Suite 500, Dayton, Ohio 45402, on behalf of the WSOS Community Action Commission, Inc.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, on behalf of Mid-Atlantic Power Supply Association, Columbia Energy Services Corporation, Columbia Energy Power Marketing Corporation, and Ohio Manufacturers' Association.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, and David Dulick, 2600 Monroe Boulevard, Norristown, Pennsylvania 19403, on behalf of Peco Energy d/b/a Exelon Energy.

Bricker & Eckler LLP, by Sally W. Bloomfield, Elizabeth H. Watts, and Amy Straker Bartemes, 100 South Third Street, Columbus, Ohio 43215-4291, and Wanda M. Schiller, Two Gateway Center, Pittsburgh, Pennsylvania 15222, on behalf of Strategic Energy L.L.C.

Sutherland Asbill & Brennan LLP, by Paul F. Forshay, Keith McCrea, James M. Bushee, David A. Codevilla, and Daniel J. Oginsky, 1275 Pennsylvania, Avenue, NW, Washington D.C. 20004-2415; and Amy Gold, P.O. Box 4402, Houston, Texas 77210, on behalf of Shell Energy Services Co., LLC.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of NewEnergy Midwest, LLC and WPS Energy Services, Inc.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and Janine L. Migden, Enron Corp., 400 Metro Place North, Dublin, Ohio 43017-3375, on behalf of Enron Energy Services Inc.

Vorys, Sater, Seymour & Pease, by M. Howard Petricoff and Joseph C. Blasko, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, and David L. Cruthirds, 1000 Louisiana Street, Suite 5800, Houston, Texas 77002-5050, on behalf of Dynegy, Inc.

Vorys, Sater, Seymour & Pease, by Philip F. Downey and Stephen M. Howard, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216-1008, on behalf of the Ohio Cable Telecommunications Association.

Thompson Hine & Flory, LLP, by Robert P. Mone and Scott A. Campbell, 10 West Broad Street, Suite 700, Columbus, Ohio 43215, on behalf of Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.

Logothetis, Pence & Doll, by John R. Doll, 111 West First Street, Suite 1100, Dayton, Ohio 45402-1156, and Speigel & McDairmid, by Cynthia S. Bogorad, Scott H. Strauss, David B. Lieb, 1350 New York Avenue NW, Suite 1100, Washington D.C. 20005-4798, on behalf of United Workers Union of America, AFL-CIO, and the Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544.

Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215, on behalf of the Association for Hospitals and Health Systems, also d/b/a Ohio Hospital Association.

Taft, Stettinius & Hollister LLP, by James J. Mayer, 1800 Firstar Tower, 425 Walnut Street, Cincinnati, Ohio 45202-3957, and Thomas J. Russell, Unicom Corporation, 125 Clark Street, Room 1535, Chicago, Illinois 60603, on behalf of Unicom Energy, Inc. and Unicom Energy Services, Inc.

Thomas M. Myers, 56000 Dilles Bottom, Shadyside, Ohio 43947, on behalf of International United Mine Workers of America (UMWA), AFL-CIO, and UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362.

OPINION:

I. HISTORY OF THESE PROCEEDINGS

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Amended Substitute Senate Bill No. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation (hereinafter SB 3) on July 6, 1999, and most provisions of SB 3 became effective on October 5, 1999. Section 4928.31, Revised Code, requires each electric utility to file with the Commission a transition plan for the company's provision of retail electric service in the state of Ohio. The plan must include a rate unbundling plan, a corporate separation plan, a plan to address operational support systems and any other technical implication issues related to competitive retail electric service, an employee assistance plan, and a consumer education plan.

On November 30, 1999, as subsequently modified and/or clarified on January 4, 20, and 27, and February 17, 2000, the Commission adopted rules for the filing and processing of electric transition plans and adopted a consumer education framework. *In the Matter of the Commission's Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Revised Code*, Case No. 99-1141-EL-ORD.

On December 30, 1999, the Columbus Southern Power Company and Ohio Power Company[1] each filed transition applications with the Commission. Each company requested approval of its electric transition plan and for authorization to recover transition revenues. Thereafter, on January 14 and February 28, 2000, AEP filed amendments to the transition plan applications.

A technical conference was conducted on January 10, 2000, at which AEP explained its filing and answered questions from participants. Preliminary objections to the applications were submitted on February 10, 11, 14, and 15, 2000. Pursuant to Section 4928.32(B), Revised Code, the Staff Report of Exceptions and Recommendations was filed on March 28, 2000. A procedural/settlement conference was conducted on March 3, 2000, and, on March 10, 2000, the attorney examiner issued an entry summarizing the rulings made during the conference and scheduling an additional prehearing conference. AEP filed additional supplemental testimony on April 18, 2000, in accordance with the attorney examiner's directive.

Intervention was granted in this proceeding to the following parties:

Appalachian People's Action Coalition (APAC);
American Municipal Power-Ohio, Inc. (AMP-Ohio);
Ameritech New Media, Inc. (ANM);
Association for Hospitals and Health Systems, also d/b/a the Ohio Hospital Association (OHA);
Buckeye Power, Inc.;
City of Cleveland (Cleveland);
Columbia Energy Services Corporation;
Columbia Energy Power Marketing Corporation (Columbia Energy companies[2]);
Dynegy, Inc. (Dynegy);
Enron Energy Services, Inc. (Enron);
Industrial Energy Users-Ohio (IEU-Ohio);
The Kroger Company (Kroger);
Mid-Atlantic Power Supply Association (MAPSA);
National Energy Marketers Association (NEMA);

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1 The two utilities will be referred to individually as "CSP" and "OP" or collectively as "the companies" or "AEP", since the utilities are operating companies within the American Electric Power family.

2 Columbia Energy Services Corporation and Columbia Energy Power Marketing Corporation jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "Columbia Energy companies".

NewEnergy Midwest, LLC (NewEnergy);
Ohio Consumers' Counsel (OCC);
Ohio Council of Retail Merchants (OCRM);
Ohio Department of Development (ODOD);
Ohio Environmental Council (OEC);
Ohio Manufacturers' Association (OMA);
Ohio Partners for Affordable Energy (OPAE);
Ohio Rural Electric Cooperatives, Inc. (OREC[3]);
Peco Energy Company, d/b/a Exelon Energy (Exelon);
PP&L EnergyPlus Co., LLC (EnergyPlus);[4]
Shell Energy Services Company, L.L.C. (Shell);
Strategic Energy L.L.P. (Strategic);
Unicom Energy, Inc.;
Unicom Energy Services, Inc. (Unicom[5]);
United Mine Workers of America, AFL-CIO;
UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362 (UMWA[6]);
Utility Workers Union of America, AFL-CIO;
Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544 (UWUA[7]);
WPS Energy Services, Inc. (WPS); and
WSOS Community Action Commission, Inc. (WSOS).

The joint motion to intervene by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company was denied on March 23, 2000. The Ohio Cable Telecommunications Association (OCTA) filed to intervene in these proceedings. However, OCTA filed two days later a notice of conditional withdrawal of its intervention request.

The second prehearing conference was conducted as scheduled on April 28, 2000. On May 8, 2000, a stipulation and recommendation (Jt. Ex. 1) was filed. That stipulation was signed by AEP, the Commission staff, APAC, Columbia Energy companies, Enron, NewEnergy, WPS, Exelon, IEU-Ohio, Kroger, MAPSA, NEMA, OCC, OCRM, OHA, OPAE, OREC, Strategic, WSOS, ODOD, and OMA. The stipulation purports to resolve all issues in these proceedings, except for one issue related to AEP's proposed gross receipts/excise tax rider. Dynegy and OEC later stated that they do not oppose the stipulation. On May 8, 2000, Shell filed testimony opposing the transition plans in several respects. The hearing

3 Buckeye Power, Inc. and Ohio Rural Electric Cooperatives, Inc. jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "OREC".

4 EnergyPlus was granted intervention in these proceedings, but filed a notice of withdrawal on March 13, 2000.

5 Unicom Energy, Inc. and Unicom Energy Services, Inc. jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "Unicom".

6 United Mine Workers of America, AFL-CIO and UMWA District Six, Local Union Nos. 1604, 1857, 1886, and 6362 jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "UMWA".

7 Utility Workers Union of America, AFL-CIO, and Utility Workers Union of America, Local Union Nos. 111, 116, 296, 468, 478, 492, and 544, jointly filed a motion to intervene in these proceedings and shall be jointly referred to as "UWUA".

began on May 9, 2000, at which time it became clear that there was opposition to the proposed stipulation. At the request of the parties, the hearing was continued and, pursuant to oral rulings made by the attorney examiners, parties interested in the gross receipts/excise tax issue were given an opportunity to present evidence for the Commission's consideration. Additionally, parties were given the opportunity to present evidence in support of and in opposition to the stipulation. The hearing then continued on May 31, June 7, 8, and 12, 2000. Only AEP, OCC, Shell, the staff, and UWUA participated in the later stages of the hearing.

On June 19, 2000, AEP and ANM file an agreement to remove from AEP's transition plan proceedings the substantive issues related to AEP's originally proposed pole attachment tariff provisions. Those two parties agreed that the pole attachment issues should instead be addressed in two cases already pending before the Commission. *In the Matter of Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Pole Attachment Tariffs and Related Matters*, Case Nos. 97-1568-EL-ATA and 97-1569-EL-ATA.

Local public hearings were conducted on June 5 and 22, 2000, in East Liverpool and Columbus, Ohio, respectively. On July 10, 25, and 26, 2000, AEP, OCC, Shell, the staff, IEU-OH, and UWUA filed briefs.

II. SUMMARY OF THE STIPULATIONS

The stipulation submitted on May 8, 2000 provides, among other things, that the companies' transition plans (as then-supplemented and revised) should be approved, except as specifically modified in that stipulation. Additionally, the stipulation states that:

(1) Neither company will impose any lost revenue charges (generation transition charges) on any switching customer (Sec. IV).

(2) All distribution electric rates in effect on December 31, 2005, will be frozen through December 31, 2007 for OP and through December 31, 2008 for CSP. Such frozen rates can, however, be adjusted to reflect the cost of complying with changes in environmental (distribution-related), tax and regulatory laws or regulations, relief from storm damage expenses, in the event of an emergency, or to reflect changes in the transmission/distribution facilities allocation (Sec. V).

(3) CSP will absorb the first $20 million of consumer education, customer choice implementation, and transition plan filing costs and will be permitted to defer the remainder of those actual costs (estimated to be $40.6 million), plus a carrying charge and recover those costs by a rider as a cost of service in future distribution rates. OP will absorb the first $20 million of consumer education, customer choice implementation, and transition plan filing costs and will be permitted to defer the remainder of those actual costs (estimated to be $45.5 million),

plus a carrying charge and recover those costs by a rider as a cost of service in future distribution rates. Determination of costs to be recovered (including the carrying charge) will be subject to Commission review (Sec. VI).

(4) During the market development period (MDP), CSP will provide a shopping incentive of 2.5 mills/kilowatt-hour to the first 25 percent of the residential class load that switches to a competitor. Any unused portion of that shopping incentive will be credited to CSP's regulatory transition cost recovery. There will be no further shopping incentive for CSP and no shopping incentive at all for OP (Sec. VII).

(5) AEP will transfer, by December 15, 2001, all operational control of transmission facilities to an operating regional transmission organization (RTO) that is approved by the Federal Energy Regulatory Commission (FERC). In the meantime, the companies will provide up to $10 million for certain costs imposed upon any supplier or customer associated with transmission charges imposed by the Pennsylvania-New Jersey-Maryland (PJM) Independent System Operator and/or Midwest Independent System Operator (MISO) for generation originating in those areas (Sec. VIII).[8]

(6) The companies shall refile: (a) the unbundled residential tariffs so as to reflect a five percent reduction in the generation component, including the regulatory transition charge (RTC) component, and shall not seek to reduce that five percent during the MDP; and (b) the tariffs and UNB-8 schedules so as to achieve a revenue-neutral rate design and equalized bills within the commercial class (Sec. IX and X).

(7) For issues being handled by the operational support plan (OSP) working group, the signatory parties accept any resolutions agreed upon by the working group. Further, the companies agree to abide by the determinations of the Commission as they relate to OSP issues (Sec. XI).

(8) With respect to customer switching, the operating companies agree that, during the MDP, customers that can take generation service from the companies during any part of May 16 through September 15 must either remain a customer through April 15 of the following year or choose a market-based tariff which will not be lower than the generation cost

8 The stipulation specifically noted that, if any governmental agency invalidates or imposes conditions upon this aspect of the stipulation, the provision is deemed withdrawn and the parties agree to negotiate in good faith to restore the value of the provision.

embedded in the standard offer. Nonaggregated residential customers will be permitted to shop three times during the MDP and to return two times to the default tariff before being required to choose from one of the above two options (Sec. XII).

(9) The companies shall provide distribution services to each retail customer or supplier of electric energy in the same quality and price and subject to the same terms and conditions as provided by the companies to similarly situated retail customers, itself or any affiliate. Before participating in an approved RTO, the companies and/or their affiliates shall provide transmission services under their pro forma transmission tariff and in compliance with federal conduct requirements (Sec. XIII).

(10) AEP will provide a $1.00 credit to suppliers for each consolidated bill issued by that provider during the first year of the MDP. The signatory parties agree to further negotiate a similar future credit. AEP shall reasonably attempt to implement supplier consolidated billing as soon as practicable (Sec. XIV).

(11) Commercial and industrial customers need only provide 90 days notice to the companies of their intent to purchase electricity from another supplier, including providing such notice 90 days prior to January 1, 2001 (Sec. XV).

(12) The companies' revenues from RTCs during the transition period and from existing frozen and unbundled rates recovered during the MDP are sufficient to recover regulatory assets as of the beginning of the MDP and for obligations required by the stipulation. The signatory parties agree that the Commission should direct the companies to amortize such regulatory assets during the MDP and thereafter, until fully amortized. Recorded regulatory assets as of the beginning of the MDP should be amortized on a per-kilowatt basis during the MDP and recovered through existing frozen and unbundled rates. Additionally, the signatory parties suggest that the Commission specifically address concerns of potential violations of the Internal Revenue Code's normalization rules regarding amortization of liabilities related to investment tax credits and excess deferred income taxes (Sec. XVII and Attach. I).

(13) Between January 1, 2006 and December 31, 2007, the first 20 percent of OP residential customer load that switches from OP's standard offer as of December 31, 2005, to another provider will not be charged the RTC. Customers that remain

on the standard offer under Section 4928.14(A) or (B), Revised Code, do not count as load that switches to a new provider (Sec. XVIII).[9]

(14) AEP and the signatory marketers will further negotiate an AEP load shaping service. All such marketing intervenors shall be notified of dates, times, and locations for such meetings (Sec. XIX).

(15) The operating companies will establish Universal Service Fund (USF) riders and Energy Efficiency Revolving Loan Fund (EERLF) riders at the rates determined by ODOD and approved by the Commission (Sec. XX).

(16) The marketer intervenors' acceptance of the companies' corporate separation plan does not constitute acceptance of the companies' interpretation of Rule 4901:1-20-16(G)(4), Ohio Administrative Code (O.A.C.), relating to code of conduct (Sec. XXI).

(17) The parties agree that the stipulation is conditioned upon acceptance in its entirety and without alteration. If the Commission rejects all or part of the agreement, or materially modifies its terms, any adversely affected party may file an application for rehearing or terminate and withdraw from the stipulation (Sec. XXII).

As noted above, a second stipulation was filed in these dockets. On June 19, 2000, AEP and ANM filed a stipulation (hereinafter referred to as the ANM agreement, so as to distinguish it from the other stipulation) to remove from AEP's transition plan proceedings the substantive issues related to AEP's originally proposed pole attachment tariff provisions. Among other things, ANM does not object to AEP's proposed withdrawal of the originally proposed pole attachment tariffs, while AEP agrees to not object to ANM's involvement (including discovery activities) in AEP's pending pole attachment tariff proceedings in Case Nos. 97-1568-EL-ATA and 97-1569-EL-ATA, *supra.* AEP further agrees to not include the originally proposed pole attachment tariff provisions in any filing in the transition plan proceedings.

III. OPPOSITION TO THE TRANSITION PLANS AND STIPULATIONS AND REVIEW OF SECTION 4928.34, REVISED CODE

Although a large number of parties were granted intervention in this proceeding, only Shell and the UWUA continued to offer any opposition to AEP's transition plans, as modified by the settlement agreements entered into by the majority of parties. The UWUA addressed only one issue related to AEP's employee assistance plan. Shell, on the other hand, takes issue with several particular aspects of the transition plan stipulation on

9 The stipulation specifically noted that, if this provision is rejected by the Commission or determined unlawful by a court, the remainder of the stipulation will remain in effect.

legal and conceptual grounds. Moreover, in Shell's view, it does not believe that the stipulation as a whole will establish the incentives for competitive suppliers to either enter AEP's service territory or remain there over time, all the while providing a financial windfall to AEP (Shell Initial Br. at 3-4, 61-66, 68; Shell Reply Br. at 1-2, 7, 17). AEP, OCC, IEU-Ohio, and the staff argue that the stipulation balances the diverse interests of nearly all parties to these proceedings and provides a number of varied benefits that are in the public interest, some of which are beyond what the Commission has authority to order (AEP Ex. 18, at 5-10; AEP Initial Br. at 10; OCC Initial Br. at 12-13; OCC Reply Br. at 11; IEU Br. at 3-4; Staff Initial Br. at 5, 6-8; Staff Reply Br. at 3-4).

As noted earlier, Section 4928.31(A), Revised Code, provides that the company's transition plan must include a rate unbundling plan that specifies the unbundled components for electric generation, transmission, and distribution service components to be charged by the company on the start date of competitive retail electric service. The transition plan must also contain a corporate separation plan, a plan to address operational support systems, an employee assistance plan, and a consumer education plan (*Id.*). AEP's transition plans include those, as well as other proposals.

Section 4928.34(A), Revised Code, requires the Commission to make determinations with respect to 15 separate "prerequisites" prior to approving a company's transition plan. Each of the opposing intervenors' comments and the 15 prerequisites is discussed below.

A. <u>Unbundling Plan and Transition Costs</u>

Beginning on the start date of competitive electric service, AEP proposes two tariff offerings: the standard tariff for customers who do not choose an alternative electric supplier and the open access distribution tariff for customers who do choose an alternative electric supplier. AEP's transition plan proposed that the open access distribution tariff be similar to the standard tariff, except that a stranded, generation transition charge (GTC) applies and no property tax credit applies (AEP Ex. 2, Part A). The individual components were derived based upon cost-of-service studies from CSP's and OP's last rate cases and were then functionalized (AEP Ex. 24A at 13-14). Adjustments were made to reflect the overall revenue level resulting from the prior rate cases and to match individual customer class revenues (*Id.*). For CSP, special adjustments were made so that the adjusted distribution component equaled the sum of the unbundled distribution and transmission components, less the revenue generated by the Open Access Transmission Tariff (OATT) (AEP Ex. 8A at 4). AEP sought recovery of stranded generation costs during the MDP and regulatory assets over the full 10-year period allowed by Section 4928.40, Revised Code (AEP Ex. 16, at 9-10; AEP Ex. 9A at 13). The companies also identified several transition costs that they requested be established as new regulatory assets (AEP Ex. 2, Part F, Sec. (B)(1)(a); AEP Ex. 16, at 6; AEP Ex. 9A at 8-12; AEP Ex. 9C at 6). AEP included the five-percent reduction required by Section 4928.40(C), Revised Code, in the proposed residential service rates (AEP Ex. 24A at 19).

AEP proposed to recover the following under the transition plan as filed:

Company	Regulatory Assets	Other Transition Costs	Total
CSP	$289,515,000	$73,684,000	$363,199,000
OP	$520,526,000	$90,260,000	$610,786,000

(AEP Ex. 2, Part F).

AEP contends that the stipulation provides additional benefits to the proposed unbundling plan and transition charges in several ways (AEP Initial Br. at 21-22, 59, 65-67). First, all distribution rates will be mostly frozen, effective December 15, 2005 through 2007 for OP and through 2008 for CSP (Jt. Ex. 1, at 3-4). Second, the frozen distribution rates can be adjusted to reflect changes in the functionalization of the transmission/distribution facilities under FERC's seven-factor test (*Id.* at 4). Third, the companies' tariffs and UNB-8 schedules will be revised consistent with Attachment 2 to the stipulation, in order to achieve revenue neutral rate designs and to equalize bill impacts for commercial customers (*Id.* at 7). Fourth, the companies will refile unbundled residential rate schedules that apply a five-percent reduction of the generation component, including the RTC component (*Id.* at 6). Fifth, the stipulation shortens the period during which the companies can recover stranded generation-related regulatory assets (from 10 years to seven years for OP and eight years for CSP) and limits the RTC levels for several years (*Id.* at 4 and Attach. 1). Next, the stipulation also specifies the levels of the RTCs for seven- and eight-year periods (*Id.* at Attach. 1). Under the stipulation, the companies can recover the following amounts as transition costs:

Company	In RTC During MDP	In Distribution Rates in Later Years
CSP	$191,156,000	$40,526,000
OP	$425,230,000	$45,533,000

(*Id.*; Tr. III, 50, 141).

Additionally, AEP states that the companies have each foregone assessing its proposed GTCs on switching customers and $20 million in customer education, customer choice implementation and transition plan filing costs (Jt. Ex. 1, at 3 and 4). The remainder of customer education, customer choice implementation and transition plan filing costs (approximately $40.5 and $45.5 million) will be deferred. CSP has agreed to provide an additional shopping incentive of 2.5 mills/kilowatt-hour for the first 25 percent of CSP's residential load that switches during the MDP, with the unused portion at December 31, 2005, being credited to the RTC (*Id.* at 5). Lastly, OP agreed that, for 2006 and 2007, the first 20 percent of OP residential customers that switch will not be charged the RTC (*Id.* at 10).

1. MDP Shopping Incentives

AEP's transition plans proposed shopping incentives that were the lower of the estimated market cost of electric energy or the unbundled generation rate (AEP Ex. 9A at 28; AEP Ex. 2 at Part H; Tr. IV, 105). AEP did not propose to increase the incentives in the MDP (AEP Ex. 9A at 28-29). The stipulation includes an explicit additional shopping incentive of 2.5 mills/kWh for the first 25 percent of CSP's residential load that switches during the MDP, with the unused portion at December 31, 2005, being credited to the RTC (Jt. Ex. 1, at 5).

In AEP's view, the transition plan stipulation would increase the proposed shopping incentive amounts by virtue of the companies agreeing to forego the amount of the GTCs and by the additional 2.5 mills/kilowatt-hour for the CSP residential class (AEP Initial Br. at 43).[10] AEP acknowledges that the stipulation states that "there will be no shopping incentive for [OP]", but contends that the language means there will be no explicit monetary incentive for OP customers during the MDP beyond that set forth in the plan (AEP Reply Br. at 22). Additionally, AEP argues that several other provisions in the stipulation constitute monetary and structural incentives to encourage shopping for CSP and OP customers (Tr. III, 148, 153, 157-160, 165, 167; AEP Reply Br. at 20-22).

Shell has criticized the shopping incentive provisions of the stipulation for several reasons. In Shell's opinion, the key to engendering good alternatives to the standard offer during the MDP is an adequate shopping credit structure that reflects the costs of serving retail markets and that adjusts to reflect significant changes in underlying wholesale costs (Shell Initial Br. at 2).[11] First, Shell argues that the shopping credit scheme does not meet the requirements of SB 3 since the stipulation does not provide any shopping incentive for CSP commercial customers or for any OP customers during the entire MDP (*Id.* at 13; Shell Ex. 7, at 4, 8). In this respect, Shell states that neither the stipulation nor the transition plan provides a complete shopping incentive that will meet the statutory minimum switch rate or the Commission's requirements (Shell Initial Br. at 13-14; Shell Reply Br. at 9-12). Next, Shell states that the stipulation's terms discriminate against OP residential ratepayers since the CSP counterparts will have a shopping credit (Shell Ex. 7, at 4; Shell Initial Br. at 13-18).

Also, Shell argues that the CSP shopping incentive is too small to produce the 20 percent load switching during the MDP (Shell Ex. 7, at 9-10; Shell Initial Br. at 12, 14, 18-19). Shell further states that there has been no evidence to support the CSP shopping credit level. Additionally, Shell states that, since there is no designated shopping credit for OP, the credit is simply the unbundled generation component in OP's tariff (Shell Ex. 6, at 49; Shell Ex. 7, at 8; Shell Initial Br. at 19). Shell provides an illustration as to why a marketer cannot effectively compete in AEP's territory under these circumstances (Shell Initial Br. at 19-23). Shell further states that the proposed fixed shopping incentives can become less economic over time, as other costs increase (Shell Initial Br. at 19-25, 32; Shell Ex. 7, at 7-10). Moreover, Shell points out that the declining block rate aspect of the shopping credits makes it increasingly difficult for competitors and will frustrate achievement of SB 3's 20 percent load switching (Shell Ex. 7, at 10; Shell Initial Br. at 23). Shell recommends that the Commission either: (1) direct the parties to return to the bargaining table to devise an

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10 AEP states that this level of shopping incentive could not have been achieved without CSP's consent because the total amount exceeds the unbundled generation component for CSP's residential customers, which is the highest level the Commission could require. See, Section 4928.04(A), Revised Code.

11 Shell's witness Dr. Wilson distinguished between a shopping credit and a shopping incentive. He explained that a "shopping credit" is the "total amount by which the switching customer's bill would be reduced because the customer is taking service from an independent provider", while the "shopping incentive" is a "component of the shopping credit and is specifically designed to encourage 20 percent of the market to shift" during the MDP (Tr. V, 74).

agreement that makes blocks of generation capacity (at predetermined prices) available for competitive suppliers (modeled after Duquesne Light Company and FirstEnergy Corporation arrangements); or (2) increase the shopping credits to the levels recommended by its expert witness (Shell Ex. 6, at 56-60; Shell Ex. 7, at 10-11; Shell Initial Br. at 26-28). Shell contends that those changes are necessary, not to make it more economical for Shell to serve customers, but to induce the 20 percent customer switching mandated by SB 3 (Shell Reply Br. at 17). Finally, Shell states that the Commission should establish a tracking mechanism to adjust the shopping credits in response to wholesale price increases or annually review the adequacy of the shopping credits in each service territory (Shell Ex. 7, at 10-11; Shell Initial Br. at 35; Shell Reply Br. at 15).

With regard to Shell's discrimination argument, AEP states that SB 3 does not require all transition plans to be the same and, thus, the fact that the 2.5 mills only applies to CSP residential customers cannot be found improper (AEP Reply Br. at 27). AEP contends that nearly every other marketer in these proceedings supports the shopping incentives of the stipulation and that is telling of their significance (*Id.* at 22). AEP criticizes Shell's expert's suggested shopping incentives as not being based upon the companies' actual unbundled generation components and as violating Section 4928.40(A), Revised Code, because they exceed the unbundled generation component (AEP Initial Br. at 44-46; AEP Reply Br. at 24). Moreover, AEP states that the Commission has no authority to order the companies to make blocks of generation available to suppliers (AEP Reply Br. at 18, 24). Therefore, the Commission should support the voluntary resolution that satisfied nearly every interested party (*Id.*).

The staff contends that SB 3's 20 percent switching rate is not a mandate (Staff Reply Br. at 5-6). Rather, it is one basis upon which the Commission can end the MDP early (*Id.*). Also, the staff states that, since the companies' transition charges are so low, the large shopping incentives that Shell seeks are not possible because the effect of Shell's request would deny the companies the opportunity to collect any transition costs from customers who shop (*Id.* at 8-9).

Shell argues first that the stipulation is discriminatory and violates SB 3 because it includes a shopping incentive during the MDP for CSP residential ratepayers, but not for OP residential ratepayers. Then, Shell also argues that there will be insufficient shopping incentives for both companies, which will be the generation shopping credit.[12] Thus, Shell has acknowledged that there would be an OP shopping incentive during the MDP under the stipulation and transition plan. At first blush, the stipulation would leave the impression that there will be no shopping incentive at all during the MDP for OP customers. However, AEP's plan included a shopping incentive for OP customers during the MDP and the stipulation did not modify that incentive. The fact that the proposed shopping incentives during the MDP vary between CSP and OP customers does not, in and of itself, lead us to conclude that the proposal before us should be rejected. In fact, we have already approved different shopping incentives between Ohio's utilities and the fact that both companies are within the AEP family does not convince us that the shopping incentives must be the same in order to be reasonable.

12 We do not believe that Shell has presented consistent arguments on this point.

The main thrust of Shell's argument against the proposed MDP shopping incentives is that they will be too small to engender competition. We do not agree with Shell's contention that the MDP shopping incentives are unlikely to affect the market in AEP's territory. We believe that the stipulation's 2.5 mills/kWh (for the first 25 percent of CSP residential customers, which is approximately 125,000 customers) will further help ensure that CSP's residential customers have an incentive to shop. The remaining customers will have an adequate incentive to shop inasmuch as the shopping incentives will equal either the estimated market cost of electric energy or 100 percent of the unbundled generation rate. As Shell's Dr. Wilson acknowledged, there is not going to be one number that gives every supplier the ability to make it in a competitive market (Tr. V, 80). We believe, however, the MDP shopping incentives proposed will effectively foster early competition by providing significant motivation to CSP and OP customers to switch retail generation suppliers.

2. Post-MDP Incentive for OP Residential Customers

Section XVIII of the stipulation states that, for 2006 and 2007, the first 20 percent of OP residential customers that switch will not be charged the RTC (Jt. Ex. 1, at 10-11). It is estimated that, in the first year (2006), approximately $5 million of RTC revenues will not be collected (Tr. III, 117). AEP will not amortize these RTC costs for future collection; it will expense the cost (*Id.* at 117-118). Shell contends that this provision of the stipulation violates SB 3 because the transition charge is "nonbypassable" and is not permitted to be discounted, per Sections 4928.37(A)(1)(b) and (3), Revised Code (Shell Initial Br. at 28-29).

In response, AEP argues that the RTC cannot be "bypassable" during the MDP only and, since the MDP will not extend beyond December 31, 2005, this provision does not violate Section 4928.37(A)(1)(b), Revised Code (AEP Reply Br. at 28-29). As for the discount aspect of the provision, AEP states that, although the provision may "have the 'effect' of discounting the RTC, [it] is no different than providing an explicit monetary shopping incentive which offsets, i.e. discounts, the transition charge" (*Id.* at 29). Also, AEP believes that the statutory provision's goal is to prevent unjust discrimination among similarly situated customers and that will not occur under the stipulation because all residential customers will be eligible, but the discount ends when 20 percent switch (*Id.* at 29-30). AEP and the staff question the consistency of Shell's arguments thus far, stating that Shell should be welcoming this provision because its intent is to provide additional encouragement to OP residential customers to switch away from the standard offer after the MDP (*Id.* at 30; Staff Reply Br. at 11).

AEP correctly points out that the "nonbypassable" restriction in Section 4928.37(A)(1)(b), Revised Code, is limited to the MDP. Thus, we do not find that the reduced RTC for OP customers in 2006 and 2007 would violate that aspect of SB 3. Additionally, Sections 4928.37(A)(1) and (3), Revised Code, specifically state that the transition charges that an electric utility can receive between the start of electric competition and the expiration of the MDP shall not be discounted by any party. The stipulation before us would not allow the discounting of the RTC to take place during the MDP. For that reason, we also conclude that Section XVIII is not contrary to SB 3. Moreover, we believe that the effect of this provision will provide OP residential customers another sizeable incentive, after the MDP, to consider switching their generation supplier. For that reason, we find it to be consistent with the pro-competitive goals of SB 3.

3. Commission's Future Ability to Respond to the Market

Shell contends that the stipulation (Sections VI and VII) unreasonably restricts the Commission's authority to modify the shopping incentive and the collection of RTCs or to carry out its market monitoring functions (Shell Ex. 7, at 7-8; Shell Initial Br. at 30, 33-34). Shell points to Sections 4928.06, 4928.40(B)(1), and 4928.39, Revised Code, for support. Shell states that the Commission's ability to respond to unanticipated market changes is very important (particularly where a fixed shopping incentive regime applies during the MDP) and the signatory parties cannot agree to rewrite that authority (Shell Initial Br. at 31-32, 33). Shell believes market participants need the assurance that the Commission can and will take immediate action to safeguard the continuing viability of retail competition (*Id.* at 32-33). As in Shell's earlier recommendation, Shell suggests a tracking mechanism to adjust the shopping credits or annual consideration of whether the credits are adequate or require modification.

AEP and the staff do not agree that Sections VI and VII of the stipulation violate SB 3. AEP states that the Commission may, but is not required to, make adjustments to transition charges (AEP Reply Br. at 32). In AEP's view, the Commission may exercise that discretion and should concur with the signatory parties' conclusion that no such further reviews are necessary (*Id.*). Further, AEP states that there is virtually nothing to which the Commission's discretionary authority could be applied for three reasons: (1) the companies have waived their claims for GTCs for the MDP; (2) RTCs can only be adjusted prospectively and only after December 31, 2004; and (3) CSP's additional shopping incentive more than eliminates those customers' RTCs for the MDP (*Id.* at. 32-33). Staff states that there are a number of statutory obligations imposed upon the Commission that are unaffected by the stipulation and the Commission will assuredly fulfill its obligations under SB 3 (Staff Reply Br. at 12).

The Commission does not believe that Sections VI and VII of the stipulation conflict with Chapter 4928, Revised Code. Section 4928.40(B)(1), Revised Code, permits the Commission to conduct periodic reviews no more often than annually and, as it determines necessary, adjust the transition charges of the electric utility. It does not require such reviews or adjustments. We believe that the stipulation establishes reasonable transition charges, shopping credits, and incentives for customers to shop. We do not believe that Section VI or VII negate the Commission's broad authority to safeguard retail competition during the MDP. Various sections of SB 3 give the Commission continued oversight to monitor the progress of competitive retail electric services, to take action where necessary, and to promote the policies of the state of Ohio set forth in Section 4928.02, Revised Code. The Commission is charged with analyzing the efficacy of the market as it progresses over time and any evidence of the abuse of market power will be a signal for a change in the process.

4. Generation Transition Charges and Stranded Generation Benefits

As noted earlier, Section IV of the stipulation states that AEP will not impose lost revenue charges or GTCs on any switching customer (Jt. Ex. 1, at 3). AEP's original transition plan proposal included a proposed GTC of $291.43 million, representing above-market, stranded generation costs (AEP Ex. 9A at 12 and 9C at 5-6; Shell Ex. 6, at 39; Tr. III, 16). This calculation was based upon the difference between the generation components of the historic rates and the companies' projected market price of generation (Shell Ex. 6, at 38, 40-41; Tr.-III, 19-21, 22). Shell states that AEP's GTC approach allows it the opportunity for a windfall because there should be no GTC so long as AEP's generating plants are valued at a market value equal or greater than their net book value (Shell Ex. 6, at 41, 46-47; Tr. V, 114-115). For Shell, the correct generating plant valuations imply that there will be no GTC or stranded costs, only stranded benefits and, therefore, Section IV of the stipulation does not support a finding that the stipulation is reasonable (*Id.* at 43-44; Shell Reply Br. at 24-25).

Shell argues that the stipulation and the proposed corporate separation plan will result in the transfer of generation assets to an unregulated affiliate at too low a value and harm ratepayers by denying them any share of the "market premiums" associated with the generation assets (Shell Ex. 6, at 43-44, 46, 83; Shell Initial Br. at 36; Shell Reply Br. at 28-29). Shell presented evidence that the more appropriate estimate of AEP's generating assets is a market value of nearly $7 billion, as opposed to the book value of approximately $2.2 billion (Shell Ex. 6, at 33-34; Tr. V, 114). Thus, in Shell's view, AEP's agreement in the stipulation to forego the GTC is meaningless because AEP had no such transition costs in the first place (Shell Initial Br. at 43). In particular, Shell's witness Dr. Wilson argues that AEP utilized overly optimistic, low market prices for power, citing to AEP's recent higher-priced purchases in the wholesale market and third-party forecasts of prices in the area (Shell Ex. 6, at 15-18). Dr. Wilson noted that changing only the estimated market price of energy, as he suggested, raised the estimated value of the generation assets by more than $2 billion and resulted in an estimate of $1.5 billion of stranded benefits (*Id.* at 21). Next, Dr. Wilson noted that AEP improperly discounted by a full 12 months (rather than by six months) and deducted office building and other nongeneration plant construction costs from generation revenues (*Id.* at 22-23). Dr. Wilson then suggested that AEP should have assumed a 10.5 percent equity cost and a capital structure of 40 percent equity and 60 percent debt (*Id.* at 24-27). With all five of those inputs modified as suggested by Dr. Wilson, the value of AEP's generating plants would raise to nearly $5 billion and exceed book value by more than $2.5 billion (*Id.* at 27, 29, and JWW-5). Dr. Wilson noted that some other adjustments could be made, but he did not attempt them (*Id.* at 24, 31, 36-37).

In addition, Shell contends that AEP will recover over $616 million in RTCs and all off-system generation sales (Shell Initial Br. at 43-44). Moreover, Shell takes issue with the fact that, under the stipulation, AEP ratepayers continue to pay for the transferred generation assets through unbundled, frozen generation rates, but not receive any benefit from the sales that the unregulated generation affiliate might make to third parties (Shell Initial Br. at 43; Shell Reply Br. at 20-21). Taken together, the book value transfer of generation assets would not serve the public interest. Shell suggests that the Commission provide AEP ratepayers a share by: (1) offsetting RTC recovery, and (2) funding more generous shopping credits for residential ratepayers with generation-related market premiums and third-party sales revenues (Shell Ex. 6, at 46; Shell Ex. 7, at 12; Tr. V, 40-41; Shell Initial Br. at 44-45; Shell Reply Br. at 29).

AEP disagrees with Shell's argument on this issue. AEP points out that its corporate separation plan does not call for the transfer of its generation assets to an unregulated affiliate. Rather, the corporate separation plan involves the creation of new transmission and distribution subsidiaries; CSP and OP will continue to own and operate the generation assets. AEP disagrees with Shell's expert's estimate of AEP's generating assets and lists a number of reasons why the analysis is flawed (AEP Reply Br. at 35-37, 42-43). Specifically, AEP argues that the most accurate value of its generating assets is not necessarily measured by selling price (*Id.* at 35). AEP contends that Dr. Wilson's proposed substitute market price of electricity is too high and constitutes an improperly averaged price at times only when the companies were purchasing power, times of high demand and higher prices (*Id.* at 36-37). Next, AEP takes issue with Shell's reliance upon the valuation report and methodology of Research Data International (RDI) because it was a preliminary, working document for the FirstEnergy transition proceedings[13], which contained incorrect or non-comparable data (*Id.* at 42-42).

Moreover, AEP states that Section 4928.35(A), Revised Code, does not entitle ratepayers to share in market premiums, even if there were any (AEP Reply Br. at 43-44). AEP further argues that Shell's suggestion that any market premiums fund larger shopping credits for switching customers is a violation of Section 4928.35(A), Revised Code, because that provision prohibits adjusting the utility's frozen unbundled rates during the MDP (AEP Reply Br. at 44). Likewise, AEP argues that Shell's suggestion to reduce the RTC violates Section 4928.39, Revised Code, because regulatory assets are a separate and distinct component of transition costs that can be adjusted only on a prospective basis (*Id.* at 44-47).

Staff contends that Shell's GTC argument is inconsistent in saying that the unbundled generation charges are above market (based on old rate case data) and below market (based upon low market values) (Staff Reply Br. at 13-14). For this reason, staff says that Shell's position should be rejected (*Id.*).

As noted earlier, if the stipulation is approved, AEP no longer seeks to recover a GTC. Therefore, the remainder of Shell's concern here is the netting of AEP's alleged stranded benefits/market premiums against transition costs. The Commission is not convinced that Dr. Wilson's analysis for determining the market value of the generating assets is fully correct. For instance, we believe Dr. Wilson's use of market price of electricity was overstated because it relied upon purchase data at times when electric prices were high and did not account for such abnormality. It also appears to improperly average the prices. We think AEP's criticisms, on these points, are valid. Changes to this one input in the valuation methodology, as Dr. Wilson noted, has a significant impact on the stranded benefits/market premiums. We also are unwilling to accept Dr. Wilson's reliance upon the RDI generation asset valuation methodology as grounds for rejecting AEP's valuation methodology. No RDI representative testified in this proceeding and the document was apparently a work in progress. Moreover, only parts of the working document are part of the record in these proceedings. Dr. Wilson's apparent use of the same methodology (with some substituted figures) does not convince us that we must

13 *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 Nos. 99-1212-EL-ETP, 99-1213-EL-ATA, and 99-1214-EL-AAM (July 19, 2000).

accept the methodology or the figures therein. In fact, AEP has raised doubt in our minds as to the accuracy of some comparison figures contained in the working document and replied upon by Dr. Wilson. For these reasons, we do not agree with Dr. Wilson's analysis or his conclusion that any stranded benefits exceed the amount of the GTC that AEP has agreed to forego as part of the stipulation.

Furthermore, we believe that the stipulation provides a reasonable and equitable resolution on this issue. AEP has agreed to forego a claim of $291.43 million. The parties to the agreement have agreed, based on all of the terms and conditions of the agreement that there is no further netting or adjustments to the transtion cost recovery during the MDP. Based upon the above findings, the Commission concludes that there are no stranded generation benefits that should either offset the RTCs or further fund the shopping incentives proposed by the stipulation.

5. Frozen Generation Rates

This next argument also relates to Section IV of the stipulation wherein neither company will impose any lost revenue charges (GTC) on any switching customer (Jt. Ex. 1, at 3). Shell argues that, for non-switching customers, the frozen, unbundled generation rates only allow AEP another opportunity to collect excessive revenues since those rates will be uneconomic in a competitive market (Shell Initial Br. at 45; Shell Reply Br. at 24).[14] Shell further believes that the stipulation itself concedes an over-recovery of generation revenues because the signatory parties agree that RTC revenues and frozen rate revenues are sufficient to recover regulatory assets (Shell Initial Br. at 47). Next, Shell contends that these frozen generation rates represent a "*de facto* second RTC charge" because, under the stipulation, the companies will amortize and recover the value of the regulatory assets in excess of the stipulated regulatory asset rates (*Id.* at 48). Shell alleges that this is unlawful since some customers will pay it, but not others, and it will discourage customer switching (*Id.*).

AEP states that SB 3's framework allows customers who do not switch to pay (as part of the unbundled generation component) generation costs that may be uneconomic (AEP Reply Br. at 48). In AEP's view, the legislature specifically chose to freeze rates at pre-SB 3 levels and did not allow, for instance, for adjustments in current costs or sales levels when unbundling generation rates (*Id.* at 49-50). Furthermore, AEP alleges that customers will pay the same frozen, unbundled generation rates, regardless of whether the companies amortize the regulatory assets over the MDP or expense them immediately (*Id.* at 51). Thus, AEP believes Shell's issue is with the requirements of SB 3 and the legislature has already disagreed with Shell's position (*Id.* at 52). Thus, there is no statutory basis to contend that the stipulation is improper (*Id.*). AEP further points out that it calculated the unbundled generation rates in accordance with Section 4928.34, Revised Code, and Shell has not taken issue with them (*Id.* at 49).

We cannot agree with Shell's arguments on this point. We find that the unbundling plan agreed to by the stipulating parties to the transition plan stipulation is reasonable and consistent with Section 4928.34, Revised Code. The evidence of record shows that the

14 Specifically, Shell contends that the frozen, unbundled generation rates are uneconomic because they are not reflective of current or competitive costs and demand (Shell Initial Br. at 46-47).

unbundling plan proposed by AEP follows the intent of Section 4928.34, Revised Code. In unbundling the rates for each customer class, AEP had to follow the requirements of SB 3, which not only dictated the manner in which the generation component would be determined, but also necessitated the use of the AEP's earlier cost-of-service studies. We find that AEP has followed the statutory scheme in unbundling its rates. Further, one of the purposes of this proceeding is to establish unbundled rates based on the already adopted cost-of-service studies, not to alter those studies or to determine whether more appropriate rates should be used when unbundling services. To do so would clearly be inconsistent with the mandate of Section 4928.34(A)(6), Revised Code, which requires the unbundling of the rates in effect on the day before the effective date of SB 3. Therefore, we find the generation components to be reasonable.

6. Distribution Rate Freeze

Section V of the stipulation states that, except in the event of certain limited changes, all distribution rates in effect on December 31, 2005, will be frozen for three years for CSP and two years for OP (Jt. Ex. 1, at 3). Shell presents two very different arguments against this provision. First, Shell views this provision as an anti-competitive albatross because, after the MDP, those frozen rates will recover generation-related retail costs and subsidize the post-MDP, "market-based" standard offer. Essentially, Shell contends that the existence of the frozen distribution rates invites the creation of a below-market rate for the standard offer and provides AEP an unfair competitive advantage over other suppliers (Shell Initial Br. at 50). Second, Shell states that the frozen distribution rates allow AEP additional opportunity for cost over-recovery since the rates are based upon costs and sales levels from old base rate cases, rather than the lower costs of a competitive market (*Id.* at 50-51). Shell also states that the rate freeze would again tie the Commission's hands in achieving the pro-competitive policies of SB 3 (*Id.* at 51).

AEP first states in response that Shell's criticism here is inconsistent with Shell's acceptance of a similar rate freeze provision in the FirstEnergy transition cases (AEP Reply Br. at 53). AEP acknowledges that the frozen distribution rates are unlikely to represent the items and levels of expense that the companies are incurring today or will be incurring at the end of 2005 (*Id.* at 54). However, AEP states that it is speculative to conclude that the companies will be over-recovering their distribution expenses in 2006, 2007 or 2008 (*Id.*). AEP notes that it and signatory consumer representatives have weighed the risks of the agreed-upon rate freeze and determined that it is a reasonable agreement as part of the overall stipulation, and the Commission should reject Shell's claims (*Id.*).

We do not agree with Shell on this point either. We believe that the distribution rate freeze will provide some certainty to customers in AEP's service territory at a time when they are evaluating the competitive generation market. That is to say, OP customers may be assured that competitive, generation-related costs are not being shifted to non-competitive, distribution charges after the MDP. Furthermore, to accept Shell's argument on this point, we must assume that the 2005 distribution rates will include generation-related costs and will not be reflective of distribution costs in 2006 through 2008. We are not willing to accept those assumptions.

7. USF Rider and EERLF Rider

On July 13, 2000, as amended on July 17, 2000, ODOD submitted a motion for approval of the USF and EERLF riders for AEP. ODOD states that the USF and EERLF riders were required to be effective on July 1, 2000 and January 1, 2001, respectively. However, due to delays in the transfer of this program, ODOD requested that the Commission make the USF rider effective September 1, 2000. On August 4, 2000, IEU-Ohio filed a motion to disapprove those proposed riders. ODOD, OCC, OPAE, APAC, and OEC filed a memorandum in support of those riders. AEP recommended that the Commission adopt ODOD's calculations in its reply brief (AEP Reply Br. at 64). By entry issued August 17, 2000, we agreed with the rates reflected in ODOD's motion. Accordingly, the USF rider rates proposed by ODOD ($0.0006240 for CSP and $0.0002998 for OP) became effective September 1, 2000. The approved rates for the EERLF rider will be $0.00010758 for both operating companies, effective January 1, 2001. A request for rehearing of our August 17, 2000 USF/EERLF ruling was then filed by IEU-Ohio, OMA, and OCRM. In a separate ruling issued this same day, we have granted rehearing in order for the ODOD and the Commission staff to provide additional data on various components of the USF riders. AEP's effective USF riders shall remain in effect pending the Commission's further review of this matter.

8. Load Shaping Service

Section XIX of the stipulation states that AEP and the signatory marketers will further negotiate an AEP load shaping service.[15] All such marketing intervenors shall be notified of dates, times, and locations for such meetings (Jt. Ex. 1, at 11).

Shell argues that the stipulation's terms relating to load shaping service are discriminatory much in the same way as the consolidated billing terms, which is fully addressed later (Shell Ex. 7, at 15; Shell Initial Br. at 58, footnote 160). Shell worries that, because negotiations will only take place with signatory marketers, the resulting load shaping services could confer benefits to only signatory parties (Tr. V, 119-120). Moreover, Shell argues that, since the generation affiliate(s) providing the load shaping service will be outside of the Commission's jurisdiction, there will be no means for curbing discriminatory actions. Shell recommends that the Commission condition any approval of the proposed corporate separation plan on the resulting unregulated generation affiliate(s)' providing services like load shaping to all market participants in a nondiscriminatory manner (Shell Initial Br. at 58-59, footnote 160).

We believe that Shell raises some valid points about the load shaping terms in the stipulation. Obviously, by agreeing to negotiate with stipulating marketers, AEP is not agreeing to negotiate with all marketers in its service territory. It is possible that any resulting load shaping service could then only confer benefits upon the negotiating marketers. However, we do not think that the entire stipulation or this part must be rejected because of this possibility. We believe that, as a condition of our approval of the stipulation and the transition plans, any resulting load shaping service must be provided in a nondiscriminatory manner. Furthermore, we direct AEP to open the negotiations to all

15 Load shaping service allows a marketer to better tailor its power purchases to meet customer demands (Tr. III, 121-122).

interested parties, not just signatory marketers, so that it is possible to develop a load shaping service that is based upon all interested persons' input. Not only do we think it is the smarter approach to take, we also think it can lead to a better end result.

9. Remaining Concerns with the Unbundling Plan and Transition Costs

Section 4928.34(A)(1), Revised Code, requires the Commission to determine whether the unbundled components for the electric transmission component of retail electric service equal the FERC tariff rates in effect on the date of approval of the transition plan. The unbundled transmission component must include a sliding scale of charges to ensure that refunds determined or approved by the FERC are flowed through to retail electric customers. After review of the filings and testimony submitted by AEP, we find that the companies' transition plans satisfy the requirements of Section 4928.34(A)(1), Revised Code.

Section 4928.34(A)(2), Revised Code, requires that the unbundled components for retail electric distribution service in the rate unbundling plan equal the difference between the costs attributable to the company's transmission and distribution rates based on the company's most recent rate proceeding, and the tariff rates for electric transmission service determined by the FERC under division (A)(1) of that code section. We find that the companies' filings satisfy this prerequisite. AEP's adjusted unbundled distribution component is the sum of the transmission and distribution components of rates in effect on October 5, 1999, less the revenue generated by the applicable OATT (AEP Ex. 24A at 15). AEP stated that, in identifying the costs in the operating companies' last rate cases, costs were assigned to functions where possible (*Id.* at 13-14). We believe that the companies' allocations are reasonable and the companies' filings, as amended by the stipulation (and subject to review in the companies' compliance filings), satisfy prerequisite (A)(2) of Section 4928.34, Revised Code.

Section 4928.34(A)(3), Revised Code, requires that all other unbundled components required by the Commission in the rate unbundling plan must equal the costs attributable to the particular service, as reflected in the company's schedule of rates and charges. In accordance with this provision, AEP's existing rates will be unbundled to separate out certain components that will be included in several riders in the operating companies' tariffs. We note that the stipulation provides for USF and EERLF riders for the companies (Jt. Ex. 1, at 11), which we fully discussed above. Based on the evidence presented in this proceeding, we find that the companies' filings, as amended by the stipulation (and subject to review of the companies' compliance filings), satisfy prerequisite (A)(3).

Section 4928.34(A)(4), Revised Code, requires that the unbundled components for retail electric generation service in the rate unbundling plan equal the residual amount remaining after the determination of the transmission, distribution, and other unbundled components, and after any tax related adjustments as necessary to reflect the effects of the amendment of Section 5727.111, Revised Code. Upon review of AEP's transition filings, as amended by the stipulation, we find that the companies have satisfied this prerequisite. In Rule 4901:1-20-03, Appendix A, Part (C)(1), O.A.C., the Commission proposed a formula for determining the residual generation component that includes transition charges. However, the Commission left open the possibility that companies could propose alternative formulations. *Rules for Electric Transition Plans, supra*, Opinion and Order at 16.

AEP proposed such an alternative in its transition filing, but has agreed in the stipulation not to impose the GTC on any switching customer (AEP Exs. 2, at 15A and 15B; Jt. Ex. 1, at 3). In addition, Section 4928.40(C), Revised Code, requires a five-percent reduction in the unbundled generation component for residential customers. Under the stipulation, the five-percent reduction is to be applied to the generation component, including the RTC component (Jt. Ex. 1, at 6). In addition, as described above, the settlement requires AEP to forego its right to seek reduction of the discount for residential customers during the MDP (*Id.*).

Section 4928.34(A)(5), Revised Code, requires that all unbundled components in the rate unbundling plan must be adjusted to reflect any rate base reductions on file with the Commission and as scheduled to be in effect by December 31, 2005, under rate settlements in effect on the effective date of this section. However, all earnings obligations, restrictions, or caps approved prior to the effective date of the statute are void. We find that the companies' filings, as amended by the stipulation, satisfy prerequisite (A)(5).

Section 4928.34(A)(6), Revised Code, requires that the total of all unbundled components is capped and, during the MDP, will equal the total of rates in effect on the day before the effective date of SB 3. The cap will be adjusted for changes in taxes, the universal service rider, and the temporary rider under Section 4928.61, Revised Code. Under AEP's filings, the total of the companies' unbundled rates is capped, with limited exceptions, during the MDP. Further, under the stipulation, distribution rates are frozen for additional years beyond the MDP, through the end of 2007 for OP and through 2008 for CSP (Jt. Ex. 1, at 3). In addition, under the companies' filings, the total of all unbundled components of existing rates and contracts equals the rates and charges of the bundled components, except for adjustments to reflect taxation changes under SB 3 and for the USF fund and EERLF riders (AEP Ex. 9A at 14-15). AEP's transition filings, as amended by the stipulation and taking into consideration our conclusion for the gross receipts/excise tax issue (discussed below), satisfy prerequisite (A)(6).

Section 4928.34(A)(7), Revised Code, requires the rate unbundling plan to comply with any rules adopted by the Commission under Section 4928.06(A), Revised Code.[16] The rules adopted by the Commission regarding unbundling of rates are set forth in Rule 4901:1-20-03, O.A.C., Appendix A. We find that the transition filings, through the various schedules and testimony submitted in this proceeding, satisfy Section 4928.34(A)(7), Revised Code.

Section 4928.34(A)(12), Revised Code, requires that the transition revenues authorized under Sections 4928.31 to 4928.40, Revised Code, be the allowable transition costs of the company pursuant to Section 4928.39, Revised Code, and that the transition charges for customer classes and rate schedules are the charges under Section 4928.40, Revised Code. Based upon the discussion above and our consideration of the record, we find that AEP's filings, subject to the modifications contained in the stipulation, satisfy the prerequisite set forth in Section 4928.34(A)(12), Revised Code.

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16 Section 4928.06, Revised Code, directs the Commission to enact rules to effectuate commencement of competitive retail electric service. The Commission has enacted rules in compliance with this statute through various generic rule proceedings.

Section 4928.34(A)(15), Revised Code, requires that all unbundled components be adjusted to reflect the elimination of the gross receipt tax imposed by Section 5727.30, Revised Code. The signatory parties agree that the revenues from the agreed-upon RTCs and from existing frozen and unbundled rates recovered during the MDP are sufficient to recover regulatory assets as of the beginning of the MDP and to provide for the stipulation's obligations (Jt. Ex. 1, at 10). We believe that this agreement is envisioned by and consistent with the requirements of Section 4928.34(A)(15), Revised Code, as well as Section 4928.34(A)(6), Revised Code.[17]

Section 4928.39, Revised Code, requires the Commission to determine the total allowable amount of the company's transition costs to be received by the company as transition revenues. Such transition costs must meet the following criteria:

(1) The costs were prudently incurred.

(2) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(3) The costs are unrecoverable in a competitive market.

(4) The utility would otherwise be entitled an opportunity to recover the costs.

We believe that, under the proposed transition plans as modified by the proposed stipulation, the amount of transition costs has been determined and that it meets the requirements for recovery through transition charges.

B. Corporate Separation Plan

Under AEP's corporate separation plan, the companies have proposed to move the regulated transmission and distribution functions into newly created affiliates (AEP Ex. 2, Part B). As a result, AEP acknowledges that the new entities will own and operate all transmission and distribution assets and be public utilities, as defined in Sections 4905.02 and 4905.03, Revised Code (AEP Ex. 9A at 19; AEP Initial Br. at 47). AEP plans to seek the necessary federal authorization for the transfer of assets in 2000 (AEP Ex. 9A at 21). The corporate separation plan will take into consideration the overlapping financial arrangements that currently exist and refinance substantially all of the obligations over a period of time (AEP Ex. 20, at 3-7). In particular, the plan involves: (1) assigning specific debt that can be identified to individual assets and leaving the remaining debt and preferred stock obligations with the generation company; (2) retire debt and preferred stock obligations; and (3) replace debt and preferred stock obligations in a manner that does not create or will eliminate future financial overlaps (*Id.* at 5-6). Nearly all service offerings will remain the same; AEP identified one service (storage water heater rental

17 Section 4928.34(A)(6), Revised Code, provides that the effect on customer rates from the tax overlap between the existing gross receipt tax and the new franchise tax "shall be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate means, to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders."

program) that will be phased out as inappropriate in a competitive market for generation services (AEP Ex. 9A at 20). AEP's corporate separation plan and supporting testimony address safeguards, separate accounting, financial arrangements, complaint procedures, education and training, and a cost allocation manual (AEP Ex. 2, Part B; AEP Exs. 9A at 22-23, 9B at 3, 13, 20).

AEP contends that the stipulation enhances the corporate separation plan in three respects (AEP Initial Br. at 50). First, the cost allocation manual (CAM) will definitively follow the uniform system of accounts, as well as the generally accepted accounting principles (Jt. Ex. 1, at 11). Second, effective with the start of competition, the distribution affiliate will not provide competitive non-electric products or services to retail customers on a commercial basis, except under pre-existing contractual obligations or when incidental to the provision of customer services and not on a commercial basis (*Id.* at 11-12). Third, the stipulation requires that employees of the affiliates not have access to any information about the transmission or distribution systems that is not contemporaneously available in the same form and manner to nonaffiliated competitors of retail electric services (*Id.*).

Shell raises two concerns with the corporate separation plan of AEP (Shell Ex. 6, at 83-84, 86-87; Shell Initial Br. at 66-67). First, Shell states that the corporate separation plan allows excessive sharing of accounting services and management with affiliates (*Id.*). Second, Shell contends that "declared emergencies" under the corporate separation plan will allow AEP to violate the affiliate code of conduct (*Id.*).

Shell presented no evidence on either of these points. We are not convinced that Shell's concerns about the language of the corporate separation plan warrant its rejection. As for the sharing of accounting services and management, we have previously explained that the corporate separation rules were not intended to prohibit all sharing of employees between affiliated entities. *Rules for Electric Transition Plans, supra,* Second Entry on Rehearing at 21. Moreover, we stated that certain centralized support functions may be permissible (*Id.*). Specifically, our corporate separation rules are "intended to require independent work/functions when the failure to maintain independent operations may have the effect of harming customers or unfairly disadvantaging unaffiliated suppliers of competitive retail electric service or non-electric products or services" (*Id.*). Without any evidence presented, we are not convinced that the AEP's plan could have the harmful effect we wish to avoid. Moreover, many interested parties have agreed to the contrary. Additionally, we are not convinced that AEP's corporate separation plan must contain a particular definition of "declared emergency". The corporate separation plan complies with Rule 4901:1-20-16(G)(4)(j), O.A.C., on this point and is acceptable.

Unlike the corporate separation plans proposed by the FirstEnergy Corporation operating companies and Cincinnati Gas & Electric Company,[18] AEP has presented a corporate separation plan that provides for structural separation by January 1, 2001 (expect for limited financial arrangements). Therefore, this Commission need not evaluate an interim plan under Section 4928.17(C), Revised Code. Section 4928.17(A)(2), Revised

[18] *In the Matter of the Application of Cincinnati Gas & Electric Company for Approval of Its Electric Transition Plan, Approval of Tariff Changes and New Tariffs, Authority to Modify Current Accounting Procedures, and Approval to Transfer its Generating Assets to an Exempt Wholesale Generator,* Case Nos. 99-1658-EL-ETP, et al. (August 31, 2000).

Code, requires that all plans satisfy the public interest in preventing unfair competitive advantage and abuse of market power. The plan must also be sufficient to ensure that no undue preference or advantage is extended to or received by the competitive retail affiliate from the utility affiliate. Section 4928(A)(3), Revised Code. We find that AEP has constructed its plan in a manner that achieves, to the extent reasonably practical, the structural separation contemplated by Section 4928.17(A)(1), Revised Code, and the corresponding Commission rules. However, the Commission reserves the right to invoke its authority to preserve fair competition, for both interim and permanent arrangements.

Section 4928.34(A)(8), Revised Code, states that the corporate separation plan required under Section 4928.31(A), Revised Code, must comply with Section 4928.17, Revised Code, and any rules adopted by the Commission pursuant to Section 4928.06(A), Revised Code. We find that the proposed corporate separation plan satisfies this prerequisite, for the reasons stated in the discussion above. We reserve the right to closely monitor the implementation of the plan to avoid competitive inequality, unfair competitive advantage or abuse of market power. We believe that through the periodic Commission review (i.e., through audits of the company's books and records, including the CAM) and the complaint process, this Commission may ensure that the corporate separation plan is implemented in accordance with the policy enunciated in SB 3.

C. <u>OSP</u>

Section 4928.34(A)(9), Revised Code, provides that the company's transition plan must comply with Commission requirements and rules regarding operational support systems and technical implementation issues pertaining to competitive retail electric service. The Commission's rules regarding operational support and technical implementation are set out in Appendix B of Rule 4901:1-20-03, O.A.C. Additionally, on November 30, 1999, the Commission issued an entry in Case No. 99-1141-EL-ORD, directing Ohio's investor-owned electric utilities and interested stakeholders to participate in a taskforce for the development of uniform business practices and electronic data interchange (EDI) standards. Pursuant to this directive, the Commission staff created the OSP taskforce (hereinafter referred to as OSPO). On May 15, 2000, numerous OSPO participants filed a pro forma certified supplier tariff (pro forma tariff) and a stipulation (hereinafter referred to as the OSPO stipulation) in each utility's transition plan case. The pro forma tariff contains a number of service regulations on which the parties were able to agree. These relate to: supplier registration and credit requirements, end-use customer enrollment process, supplier request for end-use customer information, end-use customer inquiries and requests for information, service request process, metering services and obligations, load profiling and scheduling, transmission scheduling agents, confidentiality of information, voluntary withdrawal by a competitive retail electric service provider, liability, and alternative dispute resolution. In the OSPO stipulation, the parties specifically requested the Commission to resolve issues in four general areas: (1) energy imbalance service, (2) minimum stay requirements for residential and small commercial customers returning to standard offer service, (3) consolidated billing and purchase of receivables, and (4) adoption of EDI standards. On May 18, 2000, the Commission issued an entry initiating a generic docket to establish procedures for parties desiring to file comments and reply comments regarding the OSPO stipulation and pro forma tariff. *In the Matter of the Establishment of Electronic Data Exchange Standards and Uniform Business Practices for the*

Electric Utility Industry, Case No. 00-813-EL-EDI (hereinafter 00-813). On July 20, 2000, the Commission issued a finding and order approving the OSPO stipulation and resolving the four issues left unresolved.

AEP's operational support and technical implementation plan is described in the testimony of Jeffrey Laine (AEP Ex. 14A and 14B). The OSP specifically addresses each requirement set forth in the Commission's rules (AEP Ex. 2, Part C). Specifically, as required by Rule 4901:1-20-03, Appendix B, Part (A), O.A.C., AEP's operational support plan addresses how the company intends to utilize its existing systems and what changes will be made to implement customer choice. Further, as required by Rule 4901:1-20-03, Appendix B, Part (B), O.A.C., the plan includes an electronic "clearinghouse" system that will provide functionality such as service provider registration, enrollment and switching, estimation and reconciliation, settlement, and bill data delivery (AEP Ex. 14B at 2).

Under the transition plan stipulation in this case, AEP agrees to incorporate into its transition plan, the OSPO stipulation and pro forma tariff with the exception of certain terms that the stipulating parties have agreed will apply to AEP. According to the companies, the settlement modifies the companies' plans by providing minimum stay requirements and consolidated billing credits (AEP Initial Br. at 55). AEP contends that these modifications bring additional benefits to customers and suppliers and, thus, encourage the development of the competitive retail market (*Id.*). Shell takes issue with four OSP-related items in the transition plans and stipulation: (1) supplier consolidated billing credit, (2) residential customer switching period (3) switching fee, and (4) additional certification requirements proposed by AEP.

1. <u>Supplier Consolidated Billing Credit</u>

AEP did not propose a supplier consolidated billing credit in the transition plans. Section XIV of the stipulation states that AEP will provide a $1.00 credit to suppliers for each consolidated bill issued by that provider during the first year of the MDP (Jt. Ex. 1, at 9; Tr. III, 101). The signatory parties agree to conduct further negotiations related to a similar future credit (*Id.*). Finally, that provision states that AEP shall reasonably attempt to implement supplier consolidated billing as soon as practicable (*Id.*).[19]

Shell believes that the stipulation's terms for a consolidated billing credit are inadequate to spur effective competition (Shell Ex. 7, at 16-17; Shell Initial Br. at 52). Shell, unlike most other marketers in these proceedings, provides consolidated billing for customers in Georgia and intends to do so in Ohio. First, Shell characterizes the stipulated credit amount as "anemic" and as requiring Shell's customers to pay twice for the billing service (once to Shell and a second time to AEP for costs not captured by the billing credit) (Tr. III, 115-116; Shell Initial Br. at 53; Shell Reply Br. at 27). Shell further states that the $1.00 is an arbitrary figure, while Shell's evidence supports a conclusion that CSP and OP residential accounting, collections and services average $3.70 and $4.00 per customer per month, respectively (Shell Ex. 7, at 20; Shell Initial Br. at 54-55). For that reason, Shell contends that the billing costs are virtually certain to be much higher than $1.00 (Shell Ex. 7, at 21). Shell also presented evidence of other utilities' billing costs, which were all quite a

[19] AEP has established its target date for implementing the supplier consolidated billing credit as January 1, 2001, the start of competition in Ohio (Jt. Ex. 1, at 7; Tr. III, 102, 156).

bit higher than $1.00 (*Id.* at 23, JWW-1S, JWWW-2S). For these reasons, Shell contends that the Commission should reject Section XIV and take one of two actions. Those are: either adopt a higher figure, no lower than $2.00 per bill, pending completion of a separate proceeding to determine actual costs, or require AEP to establish a separate affiliate to perform billing functions (*Id.* at 23-24; Shell Initial Br. 57).

Second, Shell also criticizes the stipulated process for modifying the credit because only signatory parties may participate in those future negotiations. Shell notes that even AEP acknowledged that, if none of the signatory parties seek such negotiations, they will not take place (Tr. III, 106; Shell Initial Br. at 58). Shell believes that none of the signatory marketers have an interest in performing consolidated billing and, therefore, there is a great risk that no future consolidated bill credit negotiations will take place. Shell also states that the stipulation's terms would have anti-competitive consequences, by excluding certain market participants from negotiations and by only allowing AEP to petition the Commission if negotiations fail (Shell Initial Br. at 59). Lastly, Shell points out that the stipulation also fails to provide a "fail-safe" credit in the event that the future negotiations are not completed in the 12-month period (Shell Ex. 7, at 24). In Shell's view, not only does AEP not have an incentive to agree to a higher billing credit, but the stipulation provides AEP with further incentive to let the 12 months expire so that the stipulated credit expires (Shell Initial Br. at 59).

AEP states that the Commission should view the stipulated consolidated billing credit as an extra bonus since AEP is not statutorily required to offer such a credit and since no other Ohio utility will be offering one as early as AEP (AEP Initial Br. at 54; AEP Reply Br. at 55). AEP also points out that the Commission did not require utilities to offer consolidated billing credits in consideration of the topic as part of the OSP issues (AEP Reply Br. at 55). Next, AEP contends that there is evidence to support the reasonableness of the stipulated credit amount. For instance, AEP's witness stated that the only avoided costs of providing billing services would be postage and the envelope, costs which are much less than $1.00 (Tr. III, 111-112, 149; AEP Reply Br. at 57). AEP also points out that Shell's witness acknowledged that other utilities have credits in the $1.00 range (Tr. V, 94). Next, AEP contends that there is no basis in Ohio law for the Commission to adopt Shell's recommendation for a separate billing affiliate. AEP next noted that it has agreed to keep Shell involved and informed of the consolidated bill discussions (Tr. III, 106-108)[20], so that concern has already been addressed by the companies (AEP Reply Br. at 58-59).

Staff contends that Shell's argument is premature because the stipulation is providing a credit only as a temporary measure during the first year (Staff Initial Br. at 9). Since "fine-tuning" can and will be addressed in the future and there are many more pressing items to address during the first phase of the transition, Shell's concern should be not adopted according to the staff (*Id.*). Additionally, the staff states that the consolidated billing credit is a unique advantage of this stipulation since no other stipulation provide such a credit (*Id.*).

We established in 00-813 a target date for consolidated bill-ready billing of no later than June 1, 2002, and a target date for supplier consolidated billing of no later than July 1,

[20] AEP agreed to also allow participation by customer groups, such as the OCC, the staff, industrials (Tr. III, 106-107).

2002. The stipulation before us, however, includes a target date for supplier consolidated billing that coincides with the start of competition. In this respect, AEP is planning to be the first utility to implement the necessary systematic changes for supplier consolidated billing. We find the stipulated target date by AEP to be reasonable.[21] Nevertheless, the crux of Shell's argument is not the start date, but the amount of the consolidated billing credit. Shell presented evidence from which it contends that the $1.00 credit is unreasonable. AEP presented evidence from which it contends that the $1.00 credit is reasonable. On balance, we conclude that, as part of an overall settlement of nearly all issues in these proceedings, the stipulated credit amount is acceptable. If this issue were fully litigated, we might very well reach a conclusion that differs from $1.00, but we cannot say that this provision (as part of a settlement reached with a broad range of interested parties and with a target of having the credit immediately available with the onset of competition) must be rejected. Additionally, AEP explained that, in the event that the system changes for supplier-consolidated billing are not in place at the start of competition on January 1, 2001, it would continue the consolidated billing credit on a day-for-day basis so that it was offered for a one-year period (Tr. III, 156-157). Lastly, inasmuch as AEP has agreed to include Shell in the future negotiations (as well as customer groups), we believe that eliminates Shell's concern that those future negotiations might not take place (Shell itself can ensure that the negotiations take place). For these reasons, we do not accept either one of Shell's suggested approaches for this issue.

2. Residential Customer Switching/Minimum Stay Requirement

The transition plan filing provided that all customers returning to the company from an alternative supplier be required to stay on the standard service offer for 12 months or the MDP, whichever is longer (AEP Ex. 2, Part A, UNB-1, Sheet Nos. 3-18D for OP and 3-14D for CSP; AEP Ex. 24A at 5-6). AEP has agreed to mitigate this requirement in the settlement (Jt. Ex 1, at 7-8). In Section XII of the stipulation, the operating companies agree that, during the MDP, customers who can take generation service from AEP between May 16 and September 15 must either remain a customer through April 15 of the following year or choose a market-based tariff which will not be lower than the generation cost embedded in the standard offer (*Id.* at 7). Under the stipulation, non-aggregated residential customers will be permitted to shop three times during the MDP and to return two times to the default tariff before being required to choose from one of the above two options (*Id.* at 8).

Shell contends that AEP's proposed minimum stay requirement violates SB 3 because SB 3 contemplates no limitation on a residential customer's freedom of movement between service options even if those movements involve a return to standard offer service (Shell Ex. 6, at 64; Shell Initial Br. at 60). Shell also claims that AEP's minimum stay provision could remove large numbers of such consumers from the competitive market place for substantial periods of time and reduce competition (Shell Initial Br. at 60).

AEP points out that Section 4928.31(A)(5), Revised Code, specifically allows transition plans to create reasonable minimum stay requirements (AEP Reply Br. at 60). Furthermore, AEP states that it is unrealistic for there to be no restrictions placed on

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[21] We note that, pursuant to Rule 4901:1-10-29(H)(1), O.A.C., the companies are still required to make rate-ready, electric disttribution utility-consolidated billing available to suppliers on January 1, 2001.

residential switching (*Id.*). Also, AEP states that the Commission has already rejected Shell's position in 00-813, there is no reason to alter that decision, and the Commission should adopt Section XII of the stipulation (*Id.* at 60-61).

With respect to the issue of AEP's minimum stay requirements and Shell's criticisms thereof, we defer to our rulings in 00-813. In that first order (page 13), we approved the use of minimum stay requirements conditioned upon the development of a market-based "come and go" rate alternative service and only in the event the customer voluntarily chooses to return to the standard offer service. We prohibited the imposition of a mandatory stay when a customer defaults to the utility's standard offer service due to the default of the supplier of electricity. We also established a uniform penalty free return to standard offer service policy and a uniform period throughout Ohio in which companies can impose a summer/stay period of May 16th through September 15th. On August 31, 2000, we granted rehearing with regard to the minimum stay ruling and adopted the "first year exemption" proposal (as opposed to the two free returns proposal) as the uniform rule in Ohio for residential and small commercial customers. This uniform rule differs from what AEP agreed upon in its stipulation, but AEP also agrees in that same stipulation to abide by our OSP determinations. Having addressed and considered Shell's arguments in 00-813, we conclude that no further conclusions need be expressed at this time. Accordingly, the Commission will modify the stipulation's treatment of minimum stay requirements so that AEP's minimum stay requirements are in full compliance with our orders in 00-813 and we reserve approval of any tariff provision relating thereto.[22] We also note that, as stated in our entry on rehearing in 00-813, our approval of the minimum stay requirements is conditioned upon the development of a uniform alternative, which will provide returning customers with a method of avoiding the minimum stay or which may eliminate the need for such requirement.

3. <u>Switching Fee and Alternative Metering Credit</u>

As part of its OSP, AEP originally proposed a $5.00 switching fee each time a customer-authorized change in provider occurs, except under certain limited circumstances (AEP Ex. 2, Part A, UNB-1, Sheet Nos. 3-3D and 3-18D for OP and Sheet Nos. 3-3D and 3-14D for CSP). AEP later modified its switching fee proposal, increasing it to $10.00 (AEP Ex. 24B at 4-5). AEP states that it proposed the increased fee because of certain Commission rules[23] and the items being discussed in the OSPO (AEP Ex. 24B at 4-

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22 We note that the stipulation's minimum stay proposal was suggested to the Commission, <u>unless</u> the OSPO agreed upon other, less restrictive minimum stay requirements. As noted above, the OSPO did not agree upon minimum stay requirements and requested a Commission ruling. That has occurred and, thus, Section XII's prefatory clause has not been triggered. We make this statement so that all interested parties fully understand that we expect that the conclusions we reached in 00-813 on the minimum stay issue will be followed. We also make this statement in light of Mr. Forrester's testimony, which would leave one to believe that the stipulation's minimum stay provision would be triggered (and not the Commission's 00-813 minimum stay conclusions) if the Commission's conclusion in 00-813 was more restrictive than the stipulation (Tr. IV, 134-135). We do not accept the approach/interpretation set forth by Mr. Forrester and explicitly modify the stipulation on this issue and we reserve approval of any tariff provision relating thereto so that AEP's minimum stay requirements comply with our decisions in 00-813.

23 AEP specifically referred to the Commission's rules in *In the Matter of the Commission's Promulgation of Rules for Minimum Competitive Retail Electric Service Standards Pursuant to Chapter 4928, Revised Code* and *In the Matter of the Commission's Promulgation of Amendments to Rules for Electric Service and*

5). Shell argues that the switching fee proposed is excessive (Shell Ex. 6, at 66; Shell Initial Br. at 66-67).[24] AEP states that the Commission should deny Shell's objection, when it is weighed against the reasonableness of the stipulation as a package (AEP Reply Br. at 61-62).

Also as part of its OSP, AEP proposed an $0.11 monthly alternative metering credit for CSP residential customers and a $0.12 monthly alternative metering credit for OP residential customers (AEP Ex. 2, Part A, UNB-1, Sheet No. 10-1D). Shell states that the proposed alternative metering credits are too low and effectively amount to barriers for suppliers to undertake alternative metering (Shell Ex. 6, at 78; Shell Initial Br. at 66-67). Shell wants the credits to reflect the utilities' full cost, not only avoided cost (Shell Ex. 6, at 78). AEP states that the Commission should likewise deny Shell's objection, when it is weighed against the reasonableness of the stipulation as a package (AEP Reply Br. at 61-62).

Similar to our finding for the consolidated billing credit amount, we conclude that the switching fee and alternative metering credit amounts are acceptable. Although we might conclude, based upon a fully litigated record, that other amounts are more appropriate, we have no evidence in the record to do so. Shell presented no such evidence as to what it contends are appropriate dollar amounts. Accordingly, we conclude that the modified switching fee and the alternative metering credit amounts proposed by AEP are acceptable, in the context of the overall settlement package presented to us.

4. <u>Supplier Registration Requirements</u>

As part of the OSP, AEP proposed a two-step certification/registration process. AEP stated that, along with the Commission's certification process, it "proposes a registration process for its service territory" (AEP Ex. 2, Part A, UNB-1, Sheet No. 3-15D – 3-16D for CSP and Sheet No. 3-19D – 3-20D for OP). The registration process would require: (1) proof of certification, (2) $100 annual fee; (3) financial instrument to ensure against defaults and a description of the plan to meet requirements of firm service customers; (4) contact information; (5) dispute resolution process for supplier customer complaints; and (6) statement of adherence with tariffs and any agreements between AEP and the supplier (*Id.*). Shell contends that approval of the OSP will allow AEP to improperly impose additional certification requirements upon suppliers, beyond the Commission's certification requirements (Shell Ex. 6, at 68-72; Shell Initial Br. at 66-67).

As noted earlier, on July 19, 2000, we approved of the OSPO's proposed pro forma tariff. That tariff contained (in Section V) the following language associated with supplier registration process, beyond the Commission's certification requirements:

> The Company shall approve or disapprove the supplier's registration within 30 calendar days of receipt of complete registration information from the supplier. The 30 day time period may be extended for up to 30 days for

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Safety Standards Pursuant to Chapter 4928, Revised Code, Case Nos. 99-1611-EL-ORD and 99-1613-EL-ORD, respectively.

24 Shell referred to the $5.00 switching fee proposal. We presume that Shell considers the current, higher fee proposal to be excessive as well and, therefore, shall address the argument.

good cause shown, or until such other time as is mutually agreed to by the supplier and the Company.

The approval process shall include, but is not limited to: successful completion of the credit requirements and receipt of the required collateral if any by the Company, executed EDI Trading Partner Agreement and Certified Supplier Service Agreement, payment and receipt of any supplier registration fee and completion of EDI testing for applicable transaction sets necessary to commence service.

The Company will notify the supplier of incomplete registration information within ten (10) calendar days of receipt. The notice to the supplier shall include a description of the missing or incomplete information.

Thus, we have agreed, not only that the electric utilities can have registration processes, but the registration processes can include some of the very items that were proposed by AEP in its transition plan. However, we believe that the stipulation before us resolves Shell's concerns over AEP's proposed registration requirements. In Section XI, the companies agree to accept resolution of issues by the OSP working group and to incorporate such in their transition plans (Jt. Ex. 1, at 7). Registration procedures were mutually resolved by the OSPO working group (as part of the pro forma tariff) after the plan was proposed and we have also approved that uniform tariff. It appears to us that AEP has accepted to modify supplier registration terms to comply with what was adopted by the OSPO working group, to which Shell was also a supporting party. We do not believe that there is any further disagreement on this issue. Accordingly, the Commission will approve the stipulation's treatment of supplier registration conditioned upon certain modifications so that AEP's supplier registration requirements are in full compliance with our orders in 00-813.

5. Overall OSP Conclusion

While the settlement provides several express modifications to the operational support aspects of the transition plan filing, which the company argues benefit customers and suppliers alike, the settlement also states that AEP will abide by Commission determinations related to OSP issues when not resolved by the OSPO (Jt. Ex. 1, at 7). Thus, the settlement sets out not only its own provisions enhancing the development of a competitive retail market, but expressly encompasses such measures that the Commission has adopted to reach the same goal. We believe the companies' OSP set forth in the stipulation, subject to modifications to comply with 00-813, is reasonable and appropriately addresses operational support systems and technical implementation procedures. Accordingly, we find the transition plan meets the statutory requirements of Section 4928.34(A)(9), Revised Code. The Commission directs its staff to finalize a bill format that includes a "price to compare" (which is the price for an electric supplier to beat in order for the customer to save money) for residential and small commercial customers.[25] As part of our approval of AEP's transition plans, the companies must meet staff's requirements regarding billing format.

D. Employee Assistance Plan (EAP)

AEP's EAP was presented in the testimony of Melinda S. Ackerman, Vice President of Human Resources for American Electric Power Service Corporation (AEP Ex. 5). Ms. Ackerman stated that, in the event of job displacement due to organizational restructuring, AEP's EAP consists of programs to help individuals locate new positions, a relocation assistance program, an educational assistance program, professional outplacement services, and a re-employment workshop (AEP Ex. 5, at 2-3). Additionally, the EAP includes programs designed to help deal with the emotional and financial issues associated with displacement, such as, counseling, severance, extended medical and life benefits, and early retirement (*Id.* at 3). Ms. Ackerman noted that the programs being sponsored as the EAP are existing already and the companies have not identified any eligible employees (*Id.*). Finally, Ms. Ackerman noted that the companies are not seeking cost recovery in the transition charge of any costs associated with the EAP (*Id.*).

UWUA points out that the EAP is lacking a disparate/adverse impact statement in accordance with Rule 4901:1-20-03, Appendix C, Part (C)(8), O.A.C. UWUA assert that, to the extent AEP seeks to "downsize" during the MDP, the Commission's regulations will require submission and approval of a disparate/adverse impact statement (UWUA Br. 2 and 4). Despite the fact that AEP has proposed no staffing changes and is not seeking any related transition cost, UWUA states that the filing of the statement is necessary before any staff downsizing takes place, not vice versa, so that the Commission can ensure the availability of reliable, safe, and efficient electric service (*Id.* at 4). Therefore, UWUA states that any approval of the transition plan (including the EAP) should include a condition requiring AEP to file and obtain approval of a disparate/adverse impact statement prior to carrying out proposed staffing changes during the MDP (*Id.* at 6-7). Additionally, UWUA states that the Commission should clarify that "downsizing" during the MDP gives rise to the requirement of advance filing and approval of a disparate/adverse impact statement (*Id.* at 5-7).

AEP responds by stating that, since it did not identify any positions affected by SB 3, no disparate/adverse impacts could be explained and, therefore, its EAP filing satisfies the Commission's filing requirements (AEP Reply Br. at 62). Next, AEP states that the UWUA would expand the requirement to apply to any downsizing, rather than just for employees that are adversely and directly affected by electric restructuring (*Id.* at 62-63). Lastly, AEP states that the UWUA's suggestion should be rejected because the Commission should not establish procedures for addressing speculative events; rather, the Commission can determine what procedures, if any, are appropriate when such a change occurs (*Id.*).

Section 4928.31(A)(4), Revised Code, requires a utility to file, as part of its transition plan, an employee assistance plan "for providing severance, retraining, early retirement,

[25] We recognize that AEP already proposed a chart that reflects the companies' prices to compare, but by tariff service (AEP Ex. 9D at Attach. I). This information should be helpful for finalizing the bill format that includes the "price to compare" information.

retention, outplacement, and other assistance for the utility's employees whose employment is affected by electric industry restructuring...." Rule 4901:1-20-03, O.A.C., Appendix C, Part (B)(3), defines "employee affected by restructuring" as an employee who is "directly and adversely affected by electric restructuring during the [MDP]...." Part (A) of the rule requires the utility to explain "how it would mitigate any necessary reductions in the electric utility workforce." Part (C) requires the EAP to provide the following components: notification of employees; outplacement assistance; relocation assistance; employee assistance, such as counseling; early retirement programs; severance packages; and "other assistance."

To the extent UWUA argues that the EAP is deficient because no disparate/adverse impact statement was included, we disagree. Since the companies concluded that no employees would be directly and adversely affected by electric restructuring during the MDP, we do not believe a disparate/adverse impact statement was required in the filing. We find that AEP's EAP satisfies the filing requirements of Rule 4901:1-20-03, O.A.C. UWUA does also seek a further requirement for AEP. UWUA states that any approval of the transition plan (including the EAP) should include a condition requiring AEP to file and obtain Commission approval of a disparate/adverse impact statement prior to carrying out proposed staffing changes during the MDP. On this point, UWUA is seeking a Commission requirement upon AEP to file, during the MDP, statements regarding what effect planned staffing changes will have on service delivery. AEP is correct in noting that UWUA's request would apply to any staff changes, not just those directly and adversely affected by electric restructuring. For that reason, we agree that UWUA's request is somewhat over-broad. However, we do not believe such a condition upon approval of the EAP is unwarranted. Rather, we find it appropriate to require AEP to provide a disparate/adverse impact statement (in this docket) should the company subsequently determine that a reduction in the staffing level is necessary due to electric restructuring during the MDP. Moreover, we will require AEP to provide the Commission with all terms and conditions related to the sale of corporate assets (including the sale of affiliate coal mines) that could have an impact on employment levels. We will of course be monitoring the service delivery and will take all necessary steps to ensure that just, reasonable, reliable and safe electric service is provided. Pursuant to Section 4928.34(A)(10), Revised Code, the Commission finds that the companies' EAP, with the above-noted conditions, sufficiently provides severance, retraining, early retirement, retention, outplacement, and other assistance for the company's employees whose employment is affected by electric industry restructuring.

E. Consumer Education Plan

Section 4928.31(A)(5), Revised Code, requires each utility's transition plan to include a consumer education plan consistent with Section 4928.42, Revised Code, and the applicable Commission rules. Section 4928.42, Revised Code, provides that, prior to the starting date of competitive retail electric service, the Commission shall prescribe and adopt a general plan by which each electric utility shall provide during its MDP consumer education on electric restructuring. Utilities are required to spend up to $16 million in the first year on consumer education within their certified service territories and an additional $17 million in decreasing amounts over the remaining years of the MDP. As part of its transition plan, AEP filed an education plan (AEP Ex. 2, Part E). AEP's education plan targets residential customers, small and mid-sized commercial customers, elected officials, community leaders, civic organizations, trade associations, and consumer groups (AEP Ex. 9A, at 25). Industrial customers' needs will be addressed on an individual basis (*Id.*). A special effort will target low-income, special needs, and hard-to-reach customers (*Id.*). The plan also describes the methods, timelines, and spending that will be used for AEP's education campaign. Some opposition to AEP's education plan was raised by the Coalition for Choice in Electricity (CCE)[26] and OCC.

As noted earlier, on November 30, 1999, the Commission issued rules for the electric transition plan proceedings. At that same time, the Commission adopted in Case No. 99-1141-EL-ORD a general plan for the electric utilities' consumer education. After the companies filed their transition plans, various intervenors filed preliminary objections. Separate staff reports were filed in each of the transition plan proceedings. In each staff report, the staff stated that the consumer education plans are consistent with the requirements issued by the Commission on November 30, 1999.[27] After reviewing all of the education plans filed in all of the transition cases and after considering the objections and comments submitted, we found in our July 19, 2000 Finding and Order in these proceedings that AEP's education plan is in compliance with Section 4928.42, Revised Code, and we approved AEP's education plan subject to a few contingencies. First, we noted that, with regard to provisions for the funding of local community-based organizations (CBO), although we did not require funding of the CBOs, we did encourage AEP to provide CBO funding. Second, we required AEP to include an unaffiliated energy marketer representative on the advisory board (we allowed AEP's operating companies to have a combined advisory group and a combined service territory-specific campaign). Third, we required that the plans for AEP include further details on how the territory-specific campaign will be managed and operated, how materials and information will be disseminated, and how funds will be allocated to activities, as well as other matters. Further, we conditioned our approval on the Commission staff's continuing supervision of the general and territory-specific plans as further details are developed for each of the consumer education programs. With the conditions to AEP's education plan set forth in our July 19, 2000 order, we find that AEP's transition plan complies with Section 4928.31(A)(5), Revised Code. Additionally, the Commission finds that the companies' consumer education plan sufficiently complies with Section 4928.34(A)(10), Revised Code,

F. <u>Independent Transmission Plan</u>

Section 4928.34(A)(13), Revised Code, requires that any transmission plan included in the transition plan must reasonably comply with Section 4928.12, Revised Code, and any rules adopted by the Commission unless the Commission, for good cause shown, authorizes the company to defer compliance until an order is issued under Section 4928.35(G), Revised Code.[28] Pursuant to Section 4928.12(A), Revised Code, no entity shall own or control transmission facilities (as defined by federal law) in Ohio as of the date of competitive retail electric service unless the entity is a member of, and transfers control of

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26 The CCE group includes various marketers, low-income representatives, IEU, OCRM, OPAE, city of Cleveland, AMP-Ohio, and OMA.

27 The staff's only recommendation for the AEP consumer education plan was the inclusion of an energy marketer representative in the advisory group.

28 Section 4928.35(G), Revised Code, governs requirements for utilities that do not have an independent transmission plan with respect to transfer of control and operation of transmission facilities.

those facilities to, one or more qualifying transmission entities. Section 4928.12(B), Revised Code, sets forth the specifications that such entities must meet.

Both existing federal[29] and state requirements are designed to achieve the same key objectives for transmission service in the development of competitive wholesale and retail energy markets. These shared objectives include: corporate separation of generation and transmission, with decisions to provide service, pricing, and expansion of facilities made on an independent basis from the transmission provider's ownership of generation facilities; creation of RTOs with sufficient scope and configuration to increase economic supply options to customers; elimination of pancaked transmission charges within a single RTO; and improved reliability of transmission service.

AEP's witness Craig Baker (AEP Exs. 6A, 6B, and 6C) explained that the company will satisfy the requirements of the Ohio statute by transferring control and operation, and ultimately ownership, of its transmission facilities to the Alliance RTO. The Alliance RTO is currently composed of FirstEnergy Corporation, AEP, Consumers Energy Company, The Detroit Edison Company, and Virginia Electric and Power Company (AEP Ex. 6A at 4).[30] As presently configured, the Alliance RTO would serve a nine-state area with a population of approximately 26 million people and a connected load of 67,000 megawatts (AEP Ex. 2, Part G at 8). The Alliance transmission system has connected generation capacity of 72,000 megawatts and will be one of the largest RTOs in the nation (*Id.*). The FERC conditionally approved the Alliance RTO in December 1999, but required that the participants modify certain aspects of the entity's independence, governance configuration, and tariff design. 89 FERC ¶61,298 (1999). AEP claims that, upon final operational implementation, the Alliance RTO will minimize pancaked transmission rates within Ohio to the extent reasonably possible and be consistent with Section 4928.12(B)(3), Revised Code (AEP Ex. 6C at 8). Until the Alliance RTO is operational and the transfer has occurred, AEP proposes that retail customers or their suppliers use AEP's OATT to transmit power and energy from alternative suppliers to the customers' load (AEP Ex. 8B at 2). Thereafter, transmission service to retail customers will cease under AEP's OATT, but be offered by the Alliance RTO OATT (*Id.*).

Additionally, in March 2000, the FERC conditionally approved the merger between American Electric Power Corporation and Central and South West Company. 90 FERC ¶61,242 (2000). That merger transaction will also impact the transferring of control, operation, and ultimately ownership of AEP's transmission facilities to the Alliance RTO.

Although the Alliance RTO may not be operational before customer choice commences in Ohio (January 1, 2001), AEP asserts that the settlement will provide benefits to participants in the Ohio retail generation market (AEP Initial Br. at 69-71). The stipulation obligates AEP to transfer control and operation, and ultimately ownership, of AEP's transmission facilities to a FERC-approved RTO no later than December 15, 2001 (Jt. Ex 1, at 5). Additionally, AEP identified three transmission-related benefits of the stipulation that are specific to the period of time before that RTO becomes operational:

29 Order No. 888, FERC Stats. & Regs. ¶ 31,089 (2000) and Order No. 2000, FERC Stats. & Regs., ¶ 31,036 (1996).

30 The Dayton Power & Light Company and Illinois Power Company have also announced their intention to join the Alliance RTO.

(1) AEP will provide two full-time equivalent positions in the System Control Center to assist transmission uses with reservations, scheduling, and tagging;
(2) AEP or its affiliates will provide transmission services for all power, including transmission of default service power and power for affiliated and nonaffiliated energy service providers only under the proposed *pro forma* transmission tariff; and
(3) AEP or its affiliates will comply with OASIS and conduct requirements promulgated by FERC.

(*Id.* at 5, 8).

Next, AEP listed four other transmission-related benefits of the stipulation. First, AEP will account for partial megawatt-hours when the load served by imports across AEP interfaces does not result in whole megawatts (Jt. Ex. 1, at 5). Second, AEP is required to make a unilateral filing at FERC to extend rollover rights to retail customers or their supplier, requesting an effective date of January 1, 2001 (*Id.*). Third, AEP will work with RTOs/ISOs and transmission-level customers to develop and implement resolutions for reciprocity and interface/seam issues and, if no other filing on this subject is made by September 1, 2000, AEP will file a proposal with the FERC (*Id.* at 5). Fourth, AEP will fund up to $10 million for costs imposed by PJM and/or the MISO on generation originating in the MISO or PJM (*Id.* at 5-6).

In Shell's reply brief it argues that the $10 million fund will not promote competition because the commitment may not reach $10 million in the short time period and because the dollars are available for only certain transmission costs (Shell Reply Br. at 30). Shell estimates that the fund will only (at best) benefit 6 percent of the AEP load (Tr. III, 162-164; Shell Reply Br. at 31).

Pursuant to Section 4928.34(A)(13), Revised Code, as an alternative to approving an independent transmission plan that complies with Section 4928.12, Revised Code, the Commission may, for good cause shown, authorize a company "to defer compliance until an order is issued under division (G) of section 4928.35 of the Revised Code." Because the Commission cannot determine, at this time, whether the Alliance ISO (or any other FERC-approved RTO as allowed by the stipulation) is compliant with the requirements of Section 4928.12, Revised Code, (due to changes that will occur as a result of the FERC's ongoing proceeding addressing the Alliance RTO, for instance), the Commission will defer approval of AEP's independent transmission plan until the opportunity is available to address the changes to the FERC-approved RTO. The Commission will exercise this later decision process through an order issued under Section 4928.35(G), Revised Code. We will authorize AEP to defer compliance with this provision until an order is issued pursuant to Section 4928.35(G), Revised Code.

We will, however, address Shell's arguments against Section VIII of the stipulation ($10 million transmission fund). On balance, we find the $10 million fund to be a unique benefit offered by the stipulation. It is one of several beneficial aspects of the stipulation. While on its own, this term of the stipulation may not create effective competition, it can (in conjunction with all of the other terms of the plans and stipulation) collectively "jump start" competition and spur the development of effective competition in AEP's territory. For these reasons, we reject Shell's criticism of the $10 million transmission fund.

G. Section 4928.34(A)(14), Revised Code

Section 4928.34(A)(14), Revised Code, states that one of the findings the Commission must make in approving a utility's transition plan is that the utility is in compliance with Sections 4928.01 through 4928.11, Revised Code, and any rules or orders adopted or issued by the Commission under those sections. We wish to make clear that we have a continuing obligation to ensure that the transition plan and its implementation are in keeping with the policy of the state, as set forth in these provisions of the statute. For example, through the monitoring of markets and enforcement with fair standards of competition, we intend to make, as a top priority, enforcement of the overarching policies of SB 3 to ensure open markets. We believe that this prerequisite is thereby satisfied.

H. Accounting Authority

The signatory parties also seek from the Commission the authority to implement various accounting entries on the regulatory books. These requested accounting approvals have been identified either in the companies' filings or in the transition plan settlement agreement and include:

(1) Requested amortization of regulatory assets during the MDP and thereafter until such regulatory assets are fully amortized.

(2) Requested amortization (on a per kilowatt-hour basis) of regulatory assets as of the beginning of the MDP that exceed the amounts on the attachment to the stipulation. Such amortization will occur during the MDP and recovered through existing frozen and unbundled rates.

(3) Requested deferral of certain new regulatory assets actual costs, plus a carrying charge, as regulatory assets for future recovery in future distribution rates.

(4) Addressing the issue of potential violations of Internal Revenue Code normalization rules with respect to amortization or regulatory liabilities of investment tax credits and deferred income taxes. The signatory parties ask that the Commission adopt certain specific language found in the settlement.

(Jt. Ex. 1, at 4, 10).

The requested accounting authority is reasonable and shall be granted. Additionally, we will approve the following language contained in the agreement:

> The base rates in the [MDP] embodied in this opinion and order include the amortization of regulatory liabilities related to [investment tax credits] no more rapidly than ratably, and the amortization of "excess

deferred taxes" using the Average Rate Assumption Method in order to avoid any potential normalization violations.

IV. THREE-PART TEST FOR EVALUATING STIPULATIONS

Rule 4901-1-30, O.A.C., authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See, Consumers Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, at 125, citing *Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Ohio-American Water Co.*; Case No. 99-1038-WW-AIR (June 29, 2000); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1004); *Ohio Edison Co.*, Case No. 91-698-EL-FOR et al. (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 547 *(citing Consumers' Counsel, supra,* at 126). The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission. *Id.*

AEP, OCC, the staff, and IEU-OH all state that the stipulations comport with this criteria (AEP Ex. 18, at 3; AEP Initial Br. at 9-14, AEP Reply Br. at 64; OCC Initial Br. at 12-13; Staff Initial Br. at 3-6; IEU-OH Br. at 3-4). Shell argues the stipulations are not in the public interest (Shell Initial Br. at 9-10).

Based on our three-prong standard of review, we find that the first criterion, that the process involved serious bargaining by knowledgeable, capable parties, is met. Counsel for the applicant and the staff, as well as the numerous intervenors, have been involved in many cases before the Commission, including a number of prior cases involving rate issues. Further, there have been few settlements in major case before this Commission in which the overwhelming majority of intervenors either supported or did not oppose the resolution of issues presented by the stipulations.

The stipulations also meet the second criterion. The stipulated resolution of these proceedings advances the public interest by resolving the extensive and complex issues raised in this proceeding without incurring the extensive time and expense of litigation that would otherwise have been required. In the case of the ANM stipulation, it will defer to an already pending proceeding the debate of pole attachments. We believe that such an agreement is in the interest of bringing the bigger restructuring issues to the forefront for resolution so that competitive choice can effectively begin on January 1, 2001. For that reason, we believe that the ANM stipulation advances the public interest.

Adoption of the stipulations also reduce significantly the number of possible appeals, and provides additional lead time to put in place the mechanisms necessary to get the customer choice program up and running. Additional evidence that the public interest is served by the stipulations is found in the support offered by representatives of residential, commercial, and industrial customers, including OCC and the Commission's staff. As indicated above, the agreement provides that certain rates will be decreased and the prior rate plan freezes extended. Some of the stipulations' tangible benefits include:

(1) Freezing, for the most part, base distribution rates for an additional 2 years beyond the MDP for OP and three additional years beyond the MDP for CSP;

(2) Absorption by both companies of the first $40 million in consumer education, customer choice implementation, and transition plan filing costs;

(3) Providing an additional shopping incentive of 2.5 mills/kilowatt-hour to the first 25 percent of the CSP residential class load that switches during the MDP, with the unused portion being credited to the RTC;

(4) Providing assistance to transmission users with reservations, scheduling, and tagging for the period of time before AEP transfers control and operation, and ultimately ownership, of AEP's transmission facilities to an RTO;

(5) Accounting for partial megawatt-hours when load imports across AEP interfaces does not result in whole megawatt-hours;

(6) Providing a fund (up to $10 million) for reimbursement of certain transmission costs incurred by suppliers or customers;

(7) Requiring the companies to reduce charges to residential customers during the MDP by 5 percent of transition costs;

(8) Revising tariffs and schedules to equalize bill impacts within the commercial class;

(9) Providing additional commitments to resolve interface, seam, and reciprocity issues impacting transmission;

(10) Providing a credit to suppliers for consolidated bills during the first year of the MDP;

(11) Providing commercial and industrial customers only a 90-day advance notice of intent to switch suppliers;

(12) For the first 20 percent of OP residential customers on its standard service offer, charging no RTC when they switch between 2006 and 2007; and

(13) Negotiating with signatory marketers (as well as Shell) regarding a load shaping service.

(Jt. Ex. 1).

We believe that the terms of these agreements, considered in their totality, provide a sufficient basis for concluding that the settlement is in the public interest. Although it will undoubtedly take some time for a fully competitive electric retail market to develop, the stipulations presented in this proceeding provide an opportunity to "jump start" the market by providing the resources necessary for retail customers to begin to shop for competitive generation services. For all these reasons, we find that the stipulations should be approved, subject to the modifications and clarifications described above.

Finally, the stipulations meet the third criterion because they do not violate any important regulatory principle or practice. Indeed, the agreements balance the interests of a broad range of parties that represent a diverse spectrum of views. As indicated in the description of stipulations provided above, the stipulations provide substantial benefits to all customer classes and shareholders. Further, the policies of the state embodied in SB 3 will be implemented more quickly and efficiently than would otherwise be possible.

V. GROSS RECEIPTS/EXCISE TAX ISSUE

As part of their applications in these cases, the companies have included a public utilities excise tax credit rider. The companies intend that the credit rider become effective on April 30, 2002, the date on which the companies contend that ratepayer liability for the public utility excise tax ends. Prior to the effective date of the credit rider, the companies would collect through their respective rates an amount, which specifically represents the ratepayers' obligation for this tax. On the effective date of the public utilities excise tax credit rider, each of the companies will begin crediting back to their customers that amount included in their respective rates representing the public utilities excise tax. The parties opposing the companies with regard to this issue (staff, OCC, and IEU-Ohio) argue that the companies will have recovered this tax expenditure fully by April 30, 2001. Therefore, it is the position of these parties that the public utilities excise tax credit rider should become effective on April 30, 2001. As noted earlier, the parties signing the stipulation in this case have reserved this issue for Commission decision.

The companies note that the public utilities excise tax is popularly referred to as the "gross receipts tax". The companies state that, contrary to this popular usage, the tax is not a "gross receipts" tax, but an "excise" tax. That is, the tax is not a tax on the gross receipts of utility companies but an assessment on the particular utility company for the privilege of doing business in a particular year, referred to as the privilege year. The amount of the tax is determined by the gross receipts of the particular utility for the year immediately prior to the privilege year, referred to as the measurement year. Because the amount of the gross revenues is not determined until the end of the measurement year, the companies argue that it is not possible for the companies' customers to have paid the tax for a particular privilege year until after the measurement year has expired.

Earl Goldhammer, a witness for AEP, testified that SB 3 provides for the final year for which electric utilities will be liable for the public utility excise tax. Mr. Goldhammer further testified that, under SB 3, Ohio electric companies' final annual public utility excise tax reports will be filed on or before August 1, 2001. These reports are for the privilege year May 1, 2001 through April 30 2002. Mr. Goldhammer notes that the last public utility excise tax lien attaches on May 1, 2001. According to Mr. Goldhammer, the report each of the companies files will indicate that company's taxable gross receipts for the preceding twelve months-May 1, 2000 through April 30, 2001. The tax the Tax Commissioner assesses is 4.75 percent times the taxable gross receipts during the measurement period -- May 1, 2000 through April 30, 2001. In accordance with statutory law, in December 2001, any tax deficiency or refund based on the assessment will be paid by or to the companies (Tr. II, 8).

Mr. Goldhammer argues that AEP does not become exempt from the public utility excise tax until the end of the privilege year ending April 30, 2002. Further. Mr. Goldhammer states the companies' tax liability for the last privilege year is not fixed as the companies receive rate payments from customers during the May 1, 2000 - April 30, 2001 measurement period. The intent of the General Assembly that the electric companies' public utility excise tax obligation continues through April 30, 2002 is evidenced, Mr. Goldhammer concludes, by the manner in which the liability for the new corporate franchise tax was implemented. The companies contend that it is recognition of the fact that electric utilities will be paying the existing public utility excise tax for the privilege of doing business and owning property in Ohio through April 30, 2002, i.e. one third of the privilege year, that the payment the General Assembly requires for the 2002 franchise tax year equals only two-thirds of the tax liability for 2002. (*Id.* at 5).

As a corollary to the above arguments, the companies cite Section 4928.34(A)(6), Revised Code, as follows:

> To the extent such total annual amount of the tax-related adjustment is greater than or less than the comparable amount of the total annual tax reduction experienced by the electric utility as a result of the provisions of Sub. S.B. No. 3 of the 123rd General Assembly, such difference shall be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers, or through other appropriate

> means to avoid placing the financial responsibility for the difference upon the electric utility or its shareholders (Emphasis added.)

Because the companies are required to pay the public utility excise tax until April 30, 2002, they argue, it is clear that the Ohio General Assembly intended that their shareholders be held harmless for the amounts the companies owe after April 30, 2001.

In their brief, the companies note that Sections 5727.33(A) and (B), Revised Code, provide that the tax is based on "the entire gross receipts actually received from all sources", excluding receipts derived wholly from interstate commerce, from business done for or with the federal government, from the sale of merchandise, and from sales to other public utilities. AEP argues that not only are rentals and other operating and non-operating receipts includable gross receipts for purposes of calculating the public utility excise tax, but not all of the gross receipts from Ohio jurisdictional utility service derive from rates which are based, in part, on recovery of a test year level of that tax expense. William Forrester, a witness for the companies, testified that when the companies' electric fuel component (EFC) increases, that increase causes an increase in the companies' public utility excise tax expense, but there is no automatic change to base rates to compensate for this increased public utility excise tax expense (AEP Ex. 9D at 5). Consequently, the companies' note their EFC rates have fluctuated since a test year level of public utility excise tax was determined in their most recent base rate cases, there has been a breach in the relationship between gross receipts from jurisdictional service and any assumed amount that customers pay in their rates for this tax expense. The companies also argue that even the Staff recognized that the disconnect caused by EFC revenues has an impact on the companies' public utility excise tax obligation and is not built into base rates as part of the test year excise tax expense (Tr. II, 83, 114).

Finally, the companies cite this Commission's decision in the FirstEnergy transition plan cases for the proposition that this Commission has already determined this issue in the companies' favor. In AEP's view, the Commission adopted in *FirstEnergy, supra,* a stipulation pursuant to which the companies can recover from ratepayers amounts representing the public utilities excise tax through April 30, 2002.

For the most part, the three parties opposing AEP with regard to this issue, staff, OCC, and IEU-Ohio, find no fault with the facts as set forth above. These parties agree that the tax is not in reality a "gross receipts tax", but an excise tax. The parties also agree with the companies' description of the method used to determine and assess the tax. The parties agree that the tax is an appropriate expense in the privilege year. The parties further agree that the companies' public utility excise tax obligation continues through April 30, 2002. The parties agree to the above, but consider these matters irrelevant to the issue at hand. According to staff, OCC, and IEU-Ohio, the issue to be resolved by the Commission in these proceedings is the liability of the companies' ratepayers for payment of the public utility excise tax through April 30, 2002. These parties contend that the ratepayer's liability ends on April 30, 2001.

The issue as viewed by staff, OCC, and IEU-Ohio is primarily a question not of tax law, but of regulatory law. These parties, looking at the Commission's ratemaking process, argue that the ratepayers have paid through the rates charged by the companies in the "measurement year" amounts representing the companies' public utility excise tax obligation for the subsequent privilege year. That is to say, the companies' ratepayers have furnished the companies' monies in the year 2001 to reflect the companies' public utility excise tax obligation in the privilege year ending April 30, 2002. According to staff, if rates were intended merely to repay the companies for current expenditures for the public utility excise tax, all that would be required would be the inclusion of the current year's payments in the cost of service. The ratemaking treatment could have stopped at that point. It did not and so staff argues that the current payments for the tax were included in the cost of service calculation, but the revenue increase was also "grossed up" explicitly to reflect this tax. In fact, staff notes, the Commission, in arriving at the rate to be charged by a company seeking a rate increase, also calculates the "tax on tax" effect, i.e., the Commission recognizes that the revenues provided to a company to pay the gross receipts tax will themselves be subject to the tax (Staff Ex. 1, at 3). The Commission would not have made these calculations, staff argues, if the Commission's only concern was to recompense the company for the then-current (test year) tax expenditure since the test year tax expenditure was not affected by the increase. Nor, staff argues, did the Commission make these calculations to reflect the next year's tax expenditure since the increased revenues the companies enjoyed in first year after an increase did not have an impact on the companies' tax payments until the following year. Staff contends that because the rates are calculated to meet a company's cost of service and then grossed up to include the ultimate tax, the rates provide not the return of a fixed dollar value, but rather a percentage of whatever the revenues are. Each dollar, staff argues, includes the tax that will ultimately be owed. Staff concludes, therefore, that the ratepayers' tax obligation tracks the payments made dollar-for-dollar and in advance. Because the companies' revenues, grossed up to include the ultimate tax increase before the taxes increase, staff argues, it is clear, as a matter of fact, that ratepayers prepay this tax expense. OCC's analysis and conclusions with regard to this coincide with those of staff in regard to the ultimate merits of the companies' proposed specific recovery of the public utility excise tax obligation through a tariff rider. IEU-Ohio states that, on balance, it believes staff and OCC have the better of the argument.

Staff is not persuaded by the companies' arguments regarding the Commission's decision in the FirstEnergy transition plan cases. Staff notes that the *FirstEnergy* settlement is a so-called "blackbox" settlement. That is, FirstEnergy will obtain certain cash flows without agreement as to what those flows represent. In Staff's opinion, FirstEnergy could allocate more of these cash flows to excise taxes and lower its earnings or not. Staff is indifferent to FirstEnergy's choice because, as staff views the matter, there are no new monies extracted from the ratepayers and the "blackbox" settlement values are reasonable, in and of themselves, without any specific recovery of the public utilities' excise tax. However, staff notes, in the AEP situation, the companies seek additional cash flows from the ratepayers specifically for this excise tax. Staff opposes the companies recovering additional cash flows representing a specific recovery of this excise tax as a double recovery of this expense item.

OCC argues that the companies' position regarding base rates not fully recovering the gross receipts tax associated with fuel revenues or regarding base rates not always fully recovering gross receipts tax expenses are not relevant to the issue with regard to the date ratepayer funding of the Ohio gross receipts tax must cease. OCC notes there is no dispute that the tax expense embedded in base rates does not track changes in the companies' respective EFC-related revenues or that base rates do not always fully recover gross receipts tax expenses. However, if under-recoveries of the public utilities excise tax had been a serious problem over the years since the companies' last rate cases, OCC argues, they should have sought rate relief.

The issue before us is purely one of fact, i.e., when does the liability of the companies' ratepayers for the public utility excise tax end. The companies' position is that the obligation of ratepayers to fund this tax ends on April 30, 2002. Staff's position with regard to this question is that ratepayers' obligation to fund the tax terminates on April 30, 2001. Of the two positions before us, the Commission finds staff's position to be the more reasonable. As staff argues the Commission's rate case process "grosses up" the revenues awarded in a rate proceeding to include the tax effect of the rate increase allowed by the Commission. Through the rate case process, the Commission even accounts for the increase in gross revenues caused by the tax itself, the so-called "tax on tax" effect. Thus, as argued by staff and OCC, the companies' customers pay in the measurement year amounts representing the companies public utilities tax obligation in the subsequent privilege year. For the purposes of illustration, assume that the measurement year for the public utilities excise tax is 2000 and the privilege year is 2001. If the Commission granted the companies a rate increase effective January 1, 2000, the ratepayers would be paying for the whole year of 2000, the measurement year, an amount that represents the companies' public utilities tax obligation for the privilege year of 2001. It is clear the ratepayers are not paying the companies' public utilities tax obligation for the privilege year of 2000 in 2000. The measurement year for privilege year 2000 is 1999. In 1999, the rate increase was not in effect.

We do not find the companies' arguments related to our adoption of the stipulation in the FirstEnergy transition plan cases to be relevant to the resolution of any issue before us in these cases. Stipulations are filed in a myriad of cases before this Commission for a number of different reasons. Sometimes a party is unsure how a particular issue will be resolved by the Commission so it will reach agreement with the other parties in the case on that issue, often giving up something in return, through the vehicle of a stipulation. Sometimes, in so-called "black box" stipulations, dollar figures will be agreed to and each of the parties may claim victory as to the same issue. Sometimes various issues are compromised just to reach settlement on issues vital to one or more of the parties. In adopting stipulations, the Commission views the stipulation as a whole; we do not, for the most part, dissect the document approving some pieces and rejecting others. If we find that the stipulation on balance is reasonable, we will generally adopt the stipulation. In making our determination, we use the three-part test delineated earlier.

In adopting the stipulation in the FirstEnergy transition plan cases, we were not passing favorably or negatively on the resolution of any particular issue contained in the stipulation. We found that the stipulation as a whole met the three-part and was reasonable. The case before us is the first case requiring a decision on the issue of ratepayer responsibility for a company's public utility excise tax obligation beyond April 30, 2001. Contrary to the arguments of the companies, our decision with respect to this issue in the cases now before us is not influenced by our decision in the FirstEnergy transition plan cases. Based upon the above findings, we are directing the companies to implement the public utilities excise tax credit rider in their respective transition plans to be effective April 30, 2001.

VI. FILED MOTIONS

A. Motions to Reject Transition Plans as Inadequate

On January 14 and 18, 2000, OCC and CCE each filed motions to reject the transition plans of AEP. Both argued that the plans should be rejected, pursuant to Section 4928.31(A), Revised Code, because the plans contain a number of substantive deficiencies that needed to be corrected and/or require plan refiling. Section 4928.31(A), Revised Code, grants the Commission authority to reject a plan or to require refiling in whole or in part of any substantially inadequate transition plan. Rule 4901:1-20-14, O.A.C., states that the Commission shall conduct an adequacy review of transition plan filings within 30 days and notify the utility of any inadequacies or if refiling is deemed necessary. If no ruling is issued in that 30-day period, the transition plan application is deemed minimally adequate. In these proceedings, the Commission did not require AEP to refile or notify it of inadequacies in the first 30-day period. Thus, by virtue of the rule, the transition plan applications were deemed minimally adequate. We, therefore, find that the motions to reject the transition plans were, in effect, already ruled upon (and denied).

B. OCTA Motion to Intervene and Subsequent Conditional Withdrawal

As noted earlier, the OCTA filed a motion to intervene in these proceedings on the ground that AEP proposed pole attachment tariffs that were improper. However, OCTA filed two days later a notice of conditional withdrawal of its intervention request, stating that, if the Commission accepts AEP's subsequent request to withdraw its originally proposed pole attachment tariffs, OCTA will withdraw its motion to intervene in these proceedings. OCTA stated grounds for intervention in these proceedings. Inasmuch as we accept AEP's withdrawal of its originally proposed pole attachment tariffs (by virtue of our acceptance of the proposed stipulations and AEP's withdrawal of new pole attachment provisions), we conclude that the condition precedent to OCTA's withdrawal from these proceedings has taken place and, therefore, we grant OCTA's withdrawal from these proceedings.

C. Motion for Protective Order

On December 30, 1999, as supplemented on January 18, 2000, AEP filed a motion for a protective order with respect to 70 pages of its transition plan filing. AEP filed the information under seal with our docketing division. AEP argues that the information is highly proprietary, competitively sensitive, and confidential. Additionally, the companies state that the information is a trade secret, as defined in Section 1333.61(D), Revised Code. They request a protective order, pursuant to Rule 4901-1-24(D), O.A.C., for the following:

(1) Three pages of the direct testimony of Edward Kahn (AEP Ex. 12, Attach. EPK-2). Those pages reveal: historic and forecasted operation and maintenance expenses by generating unit and a forecast of heat rates by generating unit.

(2) Projected emission allowance balances for the years ending 1999 and 2000 (AEP Ex. 2, Part F).

(3) Two attachments to the direct testimony of Oliver Sever (AEP Ex. 23, Attach. OJS-1 and OJS-2). Those pages address historic and forecasted fixed and variable operating and maintenance expenses by generating unit and projected fuel costs by generating unit.

(4) Study regarding customer switching (AEP Ex. 2, Part H).

At the hearing, the same information was placed into the record, as AEP Exhibit 4. We find AEP's motion for a protective order to be reasonable. In accordance with Rule 4901-1-24(F), O.A.C., our docketing Division shall maintain these items under seal for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order.

D. Motion for Compliance Tariff Review Process

On June 27, 2000, CCE filed a motion for a "compliance tariff filing, service, review, and comment procedures" in these transition plan proceedings, as well as the other pending transition plan dockets. The motion states that, because of the broad-sweeping changes that will be subject to the provisions of the tariffs ultimately approved in these proceedings, it is necessary to allow interested parties adequate time to review and comment of the proposed tariffs prior to final approval. CCE requests that the Commission order each of the applicants in the transition plan cases to serve tariffs and associated workpapers simultaneous with their filing with the Commission. CCE asks that a two-week period be provided after the date of receipt of the tariffs and workpapers in order for intervenors to review the documents and submit comments to the Commission for its consideration prior to approval of the tariffs.

CCE's motion shall be granted, subject to modification. We believe that, instead of receiving formal filings with respect to FirstEnergy's compliance tariffs, a more informal process will be beneficial to all interested parties. Accordingly, the companies and other interested parties should observe the following timelines for distributing and reviewing AEP's proposed tariffs pursuant to this decision: (1) within 14 days following the issuance of this decision, AEP should distribute (via electronic mail, fax, or overnight delivery) to all intervenors a working draft of its proposed compliance tariffs, as well as associated workpapers and UNB schedules that reflect the rates embodied in the compliance tariffs; (2) within 14 days thereafter, interested parties should circulate (via electronic mail, fax, or overnight delivery) comments to AEP and the staff regarding the working draft[31]; and (3) within 14 days thereafter, AEP shall formally file its proposed tariffs in the form of an application for approval of compliance tariffs.

Finally, to the extent any other motions or objections have been raised and they were not directly addressed above, they are denied.

31 Neither the working draft nor the informal comments are to be filed formally in the dockets of these proceedings.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) On December 30, 1999, CSP and OP filed transition plan applications, as well as applications for receipt of transition revenues. AEP supplemented those filings on January 14 and February 28, 2000.

(2) A technical conference was conducted on January 10, 2000, and preliminary objections were filed on February 10, 11, 14 and 15, 2000.

(3) A procedural/settlement conference was conducted on March 3, 2000. On March 28, 2000, the Staff Report of Exceptions and Recommendations was filed. AEP made a supplemental filing on April 18, 2000 in accordance with the attorney examiner's directive. A second prehearing conference was conducted on April 28, 2000.

(4) Intervention was granted to a number of parties. On May 8, 2000, a Stipulation and Recommendation was filed by AEP, the Commission staff, APAC, Columbia Energy companies, Enron, NewEnergy, WPS, Exelon, IEU-Ohio, Kroger, MAPSA, NEMA, OCC, OCRM, OHA, OPAE, OREC, Strategic, WSOS, ODOD, and OMA. The stipulation purports to resolve all issues in these proceedings, except for one issue related to AEP's proposed gross receipts/excise tax rider. Dynegy and OEC later stated that they do not oppose the stipulation.

(5) Evidentiary hearings were conducted on May 9 and 31 and June 7, 8, and 12, 2000. Local public hearings were held on June 5, 2000, in East Liverpool and on June 22, 2000, in Columbus, Ohio. AEP filed proof of the newspaper notices it provided for the filing of the transition plan applications and for the public hearings, in accordance with Commission directives.

(6) On June 19, 2000, AEP and ANM filed a second settlement agreement in these dockets.

(7) AEP's transition plans, as modified by the settlement agreement described above, satisfy the 15 prerequisites set forth in Section 4928.34(A), Revised Code, to the extent set forth herein.

(8) Under the stipulations, CSP can recover $191,156,000 as transition costs during the MDP. OP can recover $425,230,000 as transition costs during the MDP.

(9) The stipulations provide appropriate shopping incentives to achieve a 20 percent load switching as contemplated by Section 4928.40(A), Revised Code.

(10) AEP's transition plans, as modified by the settlement agreements, satisfies the requirements of SB 3, and are approved for the reasons and to the extent set forth herein.

(11) Our docketing division shall maintain the items filed under seal on January 18, 2000, and AEP Exhibit 4 for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order.

ORDER:

It is, therefore,

ORDERED, That AEP's transition plans and the settlement agreements filed on December 30, 1999 and May 8, 2000, respectively, are approved, to the extent set forth herein, and subject to final approval of AEP's compliance tariffs. It is, further,

ORDERED, That the tariff amendments and accounting authority requested by AEP are approved in accordance with the discussion set forth in this Opinion and Order. It is, further,

ORDERED, That CCE's motion for a compliance tariff review process is granted in part. AEP and other interested intervenors shall follow the timelines for informal review and comments with respect to the companies' compliance tariffs, and AEP shall file an application for approval of compliance tariffs in accordance with the directives set forth in this Opinion and Order. It is, further,

ORDERED, That AEP's request for a protective order is granted. It is, further,

ORDERED, That our Docketing Division shall maintain the items filed under seal on January 18, 2000, and AEP Exhibit 4 for a period of 18 months from the date of this decision. Any party wishing to extend this confidential treatment should file an appropriate motion at least 45 days in advance of the expiration of the protective order. It is, further,

ORDERED, That OCTA's request to intervene and subsequent request to withdraw from these proceedings are granted. It is, further, ORDERED, That a copy of this Opinion and Order be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Craig A. Glazer – Abstain - Not Voting

Judith A. Jones

Donald L. Mason

GLP/SJD;geb

Entered in the Journal
SEP 28 2000

A True Copy

Gary E. Vigorito
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	))))	Case No. 10-2929-EL-UNC

OPINION AND ORDER

The Commission, coming now to consider the evidence presented in this proceeding, the transcripts of the hearing, and briefs of the parties, hereby issues its opinion and order.

APPEARANCES:

Steven T. Nourse, Matthew J. Satterwhite, and Yazen Alami, American Electric Power Service Corporation, One Riverside Plaza, 29th Floor, Columbus, Ohio 43215, Porter, Wright, Morris & Arthur, LLP, by Daniel R. Conway and Christen M. Moore, 41 South High Street, Columbus, Ohio 43215, and Quinn, Emanuel, Urquhart & Sullivan, LLP, by Derek L. Shaffer, 1299 Pennsylvania Avenue NW, Suite 825, Washington, D.C. 20004, on behalf of Ohio Power Company.

Mike DeWine, Ohio Attorney General, by John H. Jones, Assistant Section Chief, and Steven L. Beeler, Assistant Attorney General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the Staff of the Public Utilities Commission of Ohio.

Bruce J. Weston, Ohio Consumers' Counsel, by Kyle L. Kern and Melissa R. Yost, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, on behalf of the residential utility consumers of Ohio Power Company.

Boehm, Kurtz & Lowry, by David F. Boehm, Michael L. Kurtz, and Jody M. Kyler, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of the Ohio Energy Group.

Taft, Stettinius & Hollister LLP, by Mark S. Yurick and Zachary D. Kravitz, 65 East State Street, Suite 1000, Columbus, Ohio 43215, on behalf of The Kroger Company.

McNees, Wallace & Nurick LLC, by Samuel C. Randazzo, Frank P. Darr, and Joseph E. Oliker, 21 East State Street, 17th Floor, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

Vorys, Sater, Seymour & Pease LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216, on behalf of Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.

Vorys, Sater, Seymour & Pease LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216, on behalf of Direct Energy Services, LLC and Direct Energy Business, LLC.

Vorys, Sater, Seymour & Pease LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216, on behalf of the Retail Energy Supply Association.

Vorys, Sater, Seymour & Pease LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, P.O. Box 1008, Columbus, Ohio 43216, Eimer Stahl LLP, by David M. Stahl, 224 South Michigan Avenue, Suite 1100, Chicago, Illinois 60604, and Sandy I-ru Grace, 101 Constitution Avenue NW, Suite 400 East, Washington, D.C. 20001, on behalf of Exelon Generation Company, LLC.

Mark A. Hayden, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, Calfee, Halter & Griswold, LLP, by James F. Lang, Laura C. McBride, and N. Trevor Alexander, 1400 KeyBank Center, 800 Superior Avenue, Cleveland, Ohio 44114, and Jones Day, by David A. Kutik and Allison E. Haedt, 901 Lakeside Avenue, Cleveland, Ohio 44114, on behalf of FirstEnergy Solutions Corp.

Bricker & Eckler LLP, by Thomas J. O'Brien, 100 South Third Street, Columbus, Ohio 43215, and Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215, on behalf of the Ohio Hospital Association.

Bricker & Eckler LLP, by Lisa G. McAlister, 100 South Third Street, Columbus, Ohio 43215, on behalf of the Ohio Manufacturers' Association.

Jeanne W. Kingery and Amy B. Spiller, 139 East Fourth Street, Cincinnati, Ohio 45202, on behalf of Duke Energy Retail Sales, LLC and Duke Energy Commercial Asset Management, Inc.

Whitt Sturtevant LLP, by Mark A. Whitt, Andrew J. Campbell, and Melissa L. Thompson, PNC Plaza, Suite 2020, 155 East Broad Street, Columbus, Ohio 43215, and Matthew White, 6100 Emerald Parkway, Dublin, Ohio 43016, on behalf of Interstate Gas Supply, Inc.

Bailey Cavalieri LLC, by Dane Stinson, 10 West Broad Street, Suite 2100, Columbus, Ohio 43215, on behalf of the Ohio Association of School Business Officials, Ohio School Boards Association, Buckeye Association of School Administrators, and Ohio Schools Council.

Kegler, Brown, Hill & Ritter, LPA, by Roger P. Sugarman, 65 East State Street, Suite 1800, Columbus, Ohio 43215, on behalf of the National Federation of Independent Business, Ohio Chapter.

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215, on behalf of Dominion Retail, Inc.

Ice Miller LLP, by Christopher L. Miller, Asim Z. Haque, and Gregory H. Dunn, 250 West Street, Columbus, Ohio 43215, on behalf of the Association of Independent Colleges and Universities of Ohio.

Ice Miller LLP, by Asim Z. Haque, Christopher L. Miller, and Gregory H. Dunn, 250 West Street, Columbus, Ohio 43215, on behalf of the city of Grove City, Ohio.

OPINION:

I. HISTORY OF THE PROCEEDING

On November 1, 2010, American Electric Power Service Corporation (AEPSC), on behalf of Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Company),[1] filed an application with the Federal Energy Regulatory Commission (FERC) in FERC Docket No. ER11-1995. On November 24, 2010, at the direction of FERC, AEPSC refiled the application in FERC Docket No. ER11-2183 (FERC filing). The application proposed to change the basis for compensation for capacity costs to a cost-based mechanism, pursuant to Section 205 of the Federal Power Act (FPA) and Section D.8 of Schedule 8.1 of the Reliability Assurance Agreement (RAA) for the regional transmission organization (RTO), PJM Interconnection, LLC (PJM), and included proposed formula rate templates under which AEP-Ohio would calculate its capacity costs.

On December 8, 2010, the Commission found that an investigation was necessary in order to determine the impact of the proposed change to AEP-Ohio's capacity charge. Consequently, the Commission sought public comments regarding the following issues: (1) what changes to the current state compensation mechanism are appropriate to determine AEP-Ohio's fixed resource requirement (FRR) capacity charge to Ohio competitive retail electric service (CRES) providers, which are referred to as alternative load serving entities (LSE) within PJM; (2) the degree to which AEP-Ohio's capacity charge is currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charge upon CRES providers and retail competition in Ohio. The Commission invited all interested stakeholders to submit written comments in

1 By entry issued on March 7, 2012, the Commission approved and confirmed the merger of CSP into OP, effective December 31, 2011. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC.

the proceeding within 30 days of issuance of the entry and to submit reply comments within 45 days of the issuance of the entry. Additionally, in light of the change proposed by AEP-Ohio, the Commission explicitly adopted as the state compensation mechanism for the Company, during the pendency of the review, the current capacity charge established by the three-year capacity auction conducted by PJM based on its reliability pricing model (RPM).

On January 20, 2011, AEP-Ohio filed a motion to stay the reply comment period and to establish a procedural schedule for hearing. In the alternative, AEP-Ohio requested an extension of the deadline to file reply comments until January 28, 2011. In support of its motion, AEP-Ohio asserted that, due to the recent rejection of its application by FERC based on the existence of a state compensation mechanism, it would be necessary for the Commission to move forward with an evidentiary hearing process to establish the proper state compensation mechanism. AEP-Ohio argued that, in light of this recent development, the parties needed more time to file reply comments.

By entry issued on January 21, 2011, the attorney examiner granted AEP-Ohio's motion to extend the deadline to file reply comments and established the new reply comment deadline as February 7, 2011. The January 21, 2011, entry also determined that AEP-Ohio's motion for the Commission to establish a procedural schedule for hearing would be considered after the reply comment period had concluded.

On January 27, 2011, in Case No. 11-346-EL-SSO, *et al.* (11-346), AEP-Ohio filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code.[2] The application was for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

Motions to intervene in the present case were filed and intervention was granted to the following parties: Ohio Energy Group (OEG); Industrial Energy Users-Ohio (IEU-Ohio); Ohio Consumers' Counsel (OCC); Ohio Partners for Affordable Energy (OPAE)[3]; Ohio Manufacturers' Association (OMA); Ohio Hospital Association (OHA); Direct Energy Services, LLC and Direct Energy Business, LLC (jointly, Direct Energy); Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (jointly, Constellation); FirstEnergy Solutions Corp. (FES); Duke Energy Retail Sales, LLC and Duke Energy Commercial Asset Management, Inc. (jointly, Duke); Exelon Generation Company, LLC (Exelon); Interstate Gas Supply, Inc. (IGS); Retail Energy Supply Association (RESA);

2 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO; *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority*, Case Nos. 11-349-EL-AAM and 11-350-EL-AAM.

3 On November 17, 2011, OPAE filed a notice of withdrawal from this case.

Ohio Association of School Business Officials, Ohio School Boards Association, Buckeye Association of School Administrators, and Ohio Schools Council (collectively, Schools); Ohio Farm Bureau Federation (OFBF); The Kroger Company (Kroger); Ohio Chapter of the National Federation of Independent Business (NFIB); Dominion Retail, Inc. (Dominion Retail); Association of Independent Colleges and Universities of Ohio (AICUO); city of Grove City, Ohio (Grove City); and Ohio Construction Materials Coalition (OCMC).[4]

Initial comments were filed by AEP-Ohio, IEU-Ohio, OMA, OHA, Constellation, Direct Energy, OEG, FES, OPAE, and OCC. Reply comments were filed by AEP-Ohio, OEG, Constellation, OPAE, FES, and OCC.

By entry issued on August 11, 2011, the attorney examiner set a procedural schedule in order to establish an evidentiary record on a proper state compensation mechanism. The evidentiary hearing was scheduled to commence on October 4, 2011, and interested parties were directed to develop an evidentiary record on the appropriate capacity cost pricing/recovery mechanism, including, if necessary, the appropriate components of any proposed capacity cost recovery mechanism. In accordance with the procedural schedule, AEP-Ohio filed direct testimony on August 31, 2011.

On September 7, 2011, a stipulation and recommendation (ESP 2 Stipulation) was filed by AEP-Ohio, Staff, and other parties to resolve the issues raised in 11-346 and several other cases pending before the Commission (consolidated cases),[5] including the above-captioned case. Pursuant to an entry issued on September 16, 2011, the consolidated cases were consolidated for the sole purpose of considering the ESP 2 Stipulation. The September 16, 2011, entry also stayed the procedural schedules in the pending cases, including this proceeding, until the Commission specifically ordered otherwise. The evidentiary hearing on the ESP 2 Stipulation commenced on October 4, 2011, and concluded on October 27, 2011.

On December 14, 2011, the Commission issued an opinion and order in the consolidated cases, modifying and adopting the ESP 2 Stipulation, including its two-tier

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4 On April 19, 2012, OCMC filed a corrected cover sheet to its motion for intervention, indicating that it did not intend to seek intervention in this case.

5 *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders*, Case No. 10-343-EL-ATA; *In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders*, Case No. 10-344-EL-ATA; *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code*, Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code*, Case No. 11-4921-EL-RDR.

capacity pricing mechanism. Subsequently, on February 23, 2012, the Commission issued an entry on rehearing in the consolidated cases, granting rehearing in part. Finding that the signatory parties to the ESP 2 Stipulation had not met their burden of demonstrating that the stipulation, as a package, benefits ratepayers and the public interest, as required by the Commission's three-part test for the consideration of stipulations, the Commission rejected the ESP 2 Stipulation. The Commission directed AEP-Ohio to file, no later than February 28, 2012, new proposed tariffs to continue the provisions, terms, and conditions of its previous ESP, including an appropriate application of capacity charges under the approved state compensation mechanism established in the present case.

By entry issued on March 7, 2012, in the above-captioned case, the Commission implemented an interim capacity pricing mechanism proposed by AEP-Ohio in a motion for relief filed on February 27, 2012. Specifically, the Commission approved a two-tier capacity pricing mechanism modeled after the one recommended in the ESP 2 Stipulation. Approval of the interim capacity pricing mechanism was subject to the clarifications contained in the Commission's January 23, 2012, entry in the consolidated cases, including the clarification to include mercantile customers as governmental aggregation customers eligible to receive capacity pricing based on PJM's RPM. Under the two-tier capacity pricing mechanism, the first 21 percent of each customer class was entitled to tier-one, RPM-based capacity pricing. All customers of governmental aggregations approved on or before November 8, 2011, were also entitled to receive tier-one, RPM-based capacity pricing. For all other customers, the second-tier charge for capacity was $255/megawatt-day (MW-day). In accordance with the March 7, 2012, entry, the interim rate was to remain in effect until May 31, 2012, at which point the charge for capacity under the state compensation mechanism would revert to the current RPM price in effect pursuant to the PJM base residual auction for the 2012/2013 delivery year.

By entry issued on March 14, 2012, the attorney examiner established a procedural schedule, which included a deadline for AEP-Ohio to revise or update its August 31, 2011, testimony. A prehearing conference occurred on April 11, 2012. The evidentiary hearing commenced on April 17, 2012, and concluded on May 15, 2012. During the evidentiary hearing, AEP-Ohio offered the direct testimony of five witnesses and the rebuttal testimony of three witnesses. Additionally, 17 witnesses testified on behalf of various intervenors and three witnesses testified on behalf of Staff.

On April 30, 2012, AEP-Ohio filed a motion for extension of the interim relief granted by the Commission in the March 7, 2012, entry. By entry issued on May 30, 2012, the Commission approved extension of the interim capacity pricing mechanism through July 2, 2012.

Initial briefs were filed by the parties on May 23, 2012, and reply briefs were filed on May 30, 2012.

II. APPLICABLE LAW

AEP-Ohio is an electric light company as defined by Section 4905.03(A)(3), Revised Code, and a public utility pursuant to Section 4905.02, Revised Code. AEP-Ohio is, therefore, subject to the jurisdiction of the Commission pursuant to Sections 4905.04, 4905.05, and 4905.06, Revised Code.

In accordance with Section 4905.22, Revised Code, all charges for service shall be just and reasonable and not more than allowed by law or by order of the Commission. Additionally, Section D.8 of Schedule 8.1 of the RAA, which is a portion of PJM's tariff approved by FERC, is informative in this case. It states:

> In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

III. DISCUSSION AND CONCLUSIONS

A. Procedural Issues

1. Motion to Dismiss

On April 10, 2012, as corrected on April 11, 2012, IEU-Ohio filed a motion to dismiss this case. In its motion, IEU-Ohio asserts that the Commission lacks statutory authority to authorize cost-based or formula-based compensation for AEP-Ohio's FRR capacity obligations from CRES providers serving retail customers in the Company's service territory. On April 13, 2012, AEP-Ohio filed a memorandum in partial opposition to IEU-Ohio's motion to dismiss. AEP-Ohio argues that the establishment of wholesale rates to be charged to CRES providers for the provision of capacity for resale to retail customers is a matter governed by federal law. AEP-Ohio notes, however, that IEU-Ohio's untimely position in its motion to dismiss is severely undercut by its previous arguments regarding Ohio law. AEP-Ohio further notes that IEU-Ohio requests that the Commission order a return to RPM-based capacity pricing upon concluding that it has no jurisdiction. AEP-Ohio argues that, if the Commission concludes that it lacks jurisdiction, it must revoke the state compensation mechanism established in its December 8, 2010, entry, revoke its orders issued in this case, and leave the matter to FERC. IEU-Ohio filed a reply to AEP-Ohio's memorandum on April 16, 2012, reiterating its request for dismissal of the case and implementation of RPM-based capacity pricing. On April 17, 2012, RESA filed a memorandum contra IEU-Ohio's motion to dismiss. RESA contends that the Commission has jurisdiction pursuant to its general supervisory powers under Sections 4905.04, 4905.05, and 4905.06, Revised Code, as well as pursuant to Section 4928.143, Revised Code, to establish a state compensation mechanism and that IEU-Ohio's motion is procedurally improper and should be denied.

At the outset of the hearing on April 17, 2012, the attorney examiner deferred ruling on IEU-Ohio's motion to dismiss (Tr. I at 21-22). Upon conclusion of AEP-Ohio's direct case, IEU-Ohio made an oral motion to dismiss the proceeding, asserting that the Company had failed to meet its burden of proof such that the Commission could approve the proposed capacity charge based on either its authority to set rates for competitive or noncompetitive retail electric service, or its authority to set rates pursuant to Section 4909.16, Revised Code (Tr. V at 1056-1059). Again, the attorney examiner deferred ruling on the motion (Tr. V at 1061).

In its brief, IEU-Ohio argues that the Commission should dismiss this case and require AEP-Ohio to reimburse all consumer representative stakeholders for the cost of participation in this proceeding and 11-346, as such costs were incurred by all consumer representative stakeholders who opposed the ESP 2 Stipulation, with reimbursement occurring through a cash payment. IEU-Ohio contends that AEP-Ohio's proposed capacity charge is unlawful and contrary to the public interest based on the common law principles codified in Chapter 1331, Revised Code, which is known as the Valentine Act and governs monopolies and anticompetitive conduct. IEU-Ohio asserts that the Valentine Act compels the Commission to reject AEP-Ohio's anticompetitive scheme to preclude free and unrestricted competition among purchasers or consumers in the sale of competitive generation service. According to IEU-Ohio, if the AEP East Interconnection Agreement (pool agreement) and the RAA are agreements having the effect of precluding free and unrestricted competition between the parties to such agreements, purchasers, or consumers, the agreements are void by operation of Ohio law. AEP-Ohio responds that IEU-Ohio urges the Commission to rely on a statute that it has no jurisdiction to enforce, noting that authority to enforce the Valentine Act is vested in the courts of common pleas, pursuant to Section 1331.11, Revised Code. AEP-Ohio adds that IEU-Ohio's request for reimbursement of litigation costs is unjustified under the circumstances of this case, unsupported by any statute or rule, and should be denied.

The Commission agrees with AEP-Ohio that it has no authority with respect to Chapter 1331, Revised Code. However, the Commission finds that it has jurisdiction to establish a state compensation mechanism, as addressed further below. IEU-Ohio's motion to dismiss this proceeding is, therefore, without merit and should be denied. In addition, IEU-Ohio's request for reimbursement of its litigation expenses is unfounded and should likewise be denied.

2. Motion for Permission to Appear *Pro Hac Vice Instanter*

On May 9, 2012, as supplemented on May 14, 2012, a motion for permission to appear *pro hac vice instanter* on behalf of AEP-Ohio was filed by Derek Shaffer. No memoranda contra were filed. The Commission finds that the motion for permission to appear *pro hac vice instanter* is reasonable and should be granted.

B. Substantive Issues

The key substantive issues before the Commission may be posed as the following questions: (1) does the Commission have jurisdiction to establish a state compensation mechanism; (2) should the state compensation mechanism for AEP-Ohio be based on the Company's capacity costs or on another pricing mechanism such as RPM-based auction prices; and (3) what should the resulting compensation be for AEP-Ohio's FRR capacity obligations. In addressing this final question, there are a number of related issues to be considered, including whether there should be an offsetting energy credit, whether AEP-Ohio's proposed cost-based capacity pricing mechanism constitutes a request for recovery of stranded generation investment, and whether OEG's alternate proposal should be adopted by the Commission.

1. Does the Commission have jurisdiction to establish a state compensation mechanism?

a. AEP-Ohio

Article 2 of the RAA provides that the RAA's purpose is "to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, Energy Efficiency Resources, and [Interruptible Load for Reliability] will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards." It further provides that the RAA should be implemented "in a manner consistent with the development of a robust competitive marketplace." Under Section 7.4 of the RAA, "[a] Party that is eligible for the [FRR] Alternative may satisfy its obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan."

In accordance with the RAA, AEP-Ohio elected to opt out of participation in PJM's RPM capacity market and instead chose to become an FRR Entity that is obligated to provide sufficient capacity for all connected load, including shopping load, in its service territory. AEP-Ohio will remain an FRR Entity through May 31, 2015 (AEP-Ohio Ex. 101 at 7-8), and, accordingly, the Company has committed to ensuring that adequate capacity resources exist within its footprint during this timeframe. Under the RAA, the default charge for providing this service is based on PJM's RPM capacity auction prices. According to AEP-Ohio, due to the decrease in RPM auction prices as reflected below and the onset of retail shopping in the Company's service territory in 2010, the adverse financial impact on the Company from supplying CRES providers with capacity at prices below cost has become significant.

	$/MW-day	
PJM Delivery Year	PJM Base Residual Auction (BRA) Price	Capacity Charge*
2010/2011	$174.29	$220.96
2011/2012	$110.00	$145.79
2012/2013	$16.46	$20.01
2013/2014	$27.73	$33.71
2014/2015	$125.99	$153.89

*BRA adjusted for final zonal capacity price, scaling factor, forecast pool requirement, and losses

As a result, AEP-Ohio made the decision to seek approval, pursuant to the RAA, to collect a cost-based capacity rate from CRES providers. In its FERC filing, AEP-Ohio proposed cost-based formula tariffs that were based on its FERC Form 1 for 2009. In response to the FERC filing, the Commission opened this docket and, in the December 8, 2010, entry, adopted capacity pricing based on the RPM auction price as the state compensation mechanism for AEP-Ohio's FRR capacity obligations. Subsequently, FERC rejected AEP-Ohio's proposed formula rate in light of the state compensation mechanism.

AEP-Ohio asserts that, because FERC has jurisdiction over wholesale electric rates and state commissions have jurisdiction over retail rate matters, it is evident that the reference to a state compensation mechanism in Section D.8 of Schedule 8.1 of the RAA contemplates a retail, not a wholesale, capacity pricing mechanism. AEP-Ohio believes that the provision of generation capacity to CRES providers is a wholesale transaction that falls within the exclusive ratemaking jurisdiction of FERC. In its brief, AEP-Ohio states that the purpose of this proceeding is to establish a wholesale capacity pricing mechanism and that retail rates cannot change as a result of this case. AEP-Ohio notes that intervenors universally agreed that the compensation paid by CRES providers to the Company for its FRR capacity obligations is wholesale in nature (Tr. IV at 795; Tr. V at 1097, 1125; Tr. VI at 1246, 1309).

b. Intervenors

As discussed above with respect to its motion to dismiss, IEU-Ohio contends that the Commission lacks statutory authority to approve a cost-based rate for capacity available to CRES providers serving retail customers in AEP-Ohio's service territory. IEU-Ohio argues that, if the Commission concludes that the provision of capacity to CRES providers is subject to the Commission's economic regulation jurisdiction, it must determine whether the service is competitive or noncompetitive. IEU-Ohio notes that generation service is classified as a competitive service under Section 4928.03, Revised Code. IEU-Ohio emphasizes that no party has claimed that capacity is not part of generation service. IEU-Ohio asserts that, if the provision of capacity is in fact considered a competitive generation service, the Commission's economic regulation jurisdiction is limited to Sections 4928.141, 4928.142, and 4928.143, Revised Code, which pertain to the establishment of an SSO. IEU-Ohio notes that these sections contain various substantive and procedural requirements that must be satisfied prior to the lawful establishment of an SSO, none of which has been satisfied in the present case, which precludes the Commission from considering or approving AEP-Ohio's proposed cost-based capacity pricing mechanism. IEU-Ohio adds that Section 4928.05, Revised Code, prohibits the Commission from regulating competitive retail electric service under its traditional cost-based ratemaking authority contained in Chapter 4909, Revised Code. IEU-Ohio continues that, if the provision of capacity is nevertheless deemed a noncompetitive service, the Commission cannot approve AEP-Ohio's proposed capacity pricing mechanism because the Company has failed to satisfy any of the statutory requirements found in Chapter 4909, Revised Code. IEU-Ohio also argues that AEP-Ohio has failed to satisfy the requirements of Section 4909.16, Revised Code, which must be met before the Commission can authorize a rate increase to avoid financial harm. Finally, IEU-Ohio maintains that the Commission's general supervisory authority is not a basis for approving rates. Even aside from the question of the Commission's jurisdiction, IEU-Ohio contends that AEP-Ohio has not met the burden of proof that would apply pursuant to Section 4909.16, 4909.18, or 4928.143, Revised Code.

RESA and Direct Energy (jointly, Suppliers) argue that the Commission has authority under state law to establish the state compensation mechanism. The Suppliers contend that the Commission, pursuant to its general supervisory authority contained within Sections 4905.04, 4905.05, and 4905.06, Revised Code, may initiate investigations to review rates and charges, as it has done in this case to consider AEP-Ohio's capacity pricing mechanism for its FRR obligations. The Suppliers point out that, in the December 8, 2010, entry, the Commission even referenced those sections and noted that it has the authority to supervise and regulate all public utilities within its jurisdiction. Additionally, the Suppliers believe that the Commission may establish the state compensation mechanism pursuant to Sections 4928.141(A) and 4928.143(B)(2)(d), Revised Code, which enable the Commission to set rates for certain competitive services as part of an ESP. The Suppliers also assert that the provision of capacity is a retail electric service, as defined by Section 4928.01(A)(27), Revised Code, given that it is a service arranged for ultimate consumers in this state.

In response to the Suppliers, IEU-Ohio argues that the Commission's general supervisory authority does not provide it with unlimited powers to approve rates. IEU-Ohio further disputes the Suppliers' claim that Section 4928.143(B)(2)(d), Revised Code, offers another statutory basis upon which to approve capacity pricing for CRES providers, noting, among other reasons, that this is not an SSO proceeding.

c. Conclusion

As a creature of statute, the Commission has and may exercise only the authority conferred upon it by the General Assembly. *Tongren v. Pub. Util. Comm.*, 85 Ohio St.3d 87, 88 (1999). Thus, as an initial matter, the Commission must determine whether there is a statutory basis under Ohio law upon which it may rely to establish a state compensation mechanism. As we noted in the December 8, 2010, entry, Sections 4905.04, 4905.05, and 4905.06, Revised Code, grant the Commission authority to supervise and regulate all public utilities within its jurisdiction. We further noted that AEP-Ohio is an electric light company as defined in Section 4905.03(A)(3), Revised Code, and a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of the Commission. We affirm our prior finding that Sections 4905.04, 4905.05, and 4905.06, Revised Code, grant the Commission the necessary statutory authority to establish a state compensation mechanism.

IEU-Ohio contends that the Commission must determine whether capacity service is a competitive or noncompetitive retail electric service pursuant to Chapter 4928, Revised Code. Section 4928.05(A)(1), Revised Code, provides that competitive retail electric service is, to a large extent, exempt from supervision and regulation by the Commission, including pursuant to the Commission's general supervisory authority contained in Sections 4905.04, 4905.05, and 4905.06, Revised Code. Section 4928.05(A)(2), Revised Code, provides that noncompetitive retail electric service, on the other hand, generally remains subject to supervision and regulation by the Commission. Prior to determining whether a retail electric service is competitive or noncompetitive, however, we must first confirm that it is indeed a retail electric service. Section 4928.01(A)(27), Revised Code, defines a retail electric service as "any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption." In this case, the electric service in question (*i.e.*, capacity service) is provided by AEP-Ohio for CRES providers, with CRES providers compensating the Company in return for its FRR capacity obligations. Such capacity service is not provided directly by AEP-Ohio to retail customers. (AEP-Ohio Ex. 101 at 11; Tr. I at 63.) Although the capacity service benefits shopping customers in due course, they are initially one step removed from the transaction, which is more appropriately characterized as an intrastate wholesale matter between AEP-Ohio and each CRES provider operating in the Company's service territory. As AEP-Ohio notes, many of the parties, including the Company, regard the capacity compensation assessed by the Company to CRES providers as a wholesale matter (Tr. IV at 795; Tr. V at 1097, 1125; Tr. VI at 1246, 1309). We agree that the provision of capacity for CRES providers by AEP-Ohio, pursuant to the Company's FRR capacity obligations, is not a retail electric service as defined by Ohio law. Accordingly, we find it unnecessary to determine whether capacity service is considered a competitive or noncompetitive service under Chapter 4928, Revised Code.

The Commission recognizes that, pursuant to the FPA, electric sales for resale and other wholesale transactions are generally subject to the exclusive jurisdiction of FERC. In this case, however, our exercise of jurisdiction, for the sole purpose of establishing an appropriate state compensation mechanism, is consistent with the governing section of the RAA, which, as a part of PJM's tariffs, has been approved by FERC and was accepted by AEP-Ohio when the RAA was signed on its behalf by AEPSC.[6] Section D.8 of Schedule 8.1 of the RAA acknowledges the authority of a state regulatory jurisdiction, such as the Commission, to establish a state compensation mechanism. It further provides that a state compensation mechanism, once established, prevails over the other compensation methods that are addressed in that section. Additionally, FERC has found that the RAA does not

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[6] In its order rejecting the FERC filing, FERC noted its approval of the RAA pursuant to a settlement agreement. *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011), *citing PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006), *order on reh'g*, 119 FERC ¶ 61,318, *reh'g denied*, 121 FERC ¶ 61,173 (2007), *aff'd sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, D.C. Circuit Case No. 07-1336 (March 17, 2009) (unpublished). FERC also noted that the RAA was voluntarily signed on behalf of AEP-Ohio.

permit AEPSC to change the state compensation mechanism. In fact, FERC rejected AEPSC's proposed formula rate, given the existence of the state compensation mechanism established by the Commission in its December 8, 2010, entry.[7]

2. Should the state compensation mechanism for AEP-Ohio be based on the Company's capacity costs or on another pricing mechanism such as RPM-based auction prices?

a. AEP-Ohio

As an initial matter, AEP-Ohio notes that it recently declared that it will not continue its status as an FRR Entity and instead will fully participate in the RPM capacity market auctions, beginning on June 1, 2015, which is the earliest possible date on which to transition from an FRR Entity to a full participant in the RPM capacity market. AEP-Ohio points out that this development narrows the scope of this proceeding to establishing a three-year transitional, rather than permanent, form of compensation for its FRR capacity obligations.

AEP-Ohio argues that it is entitled to full compensation for the capacity that it supplies to CRES providers pursuant to its FRR obligations. Specifically, AEP-Ohio contends that Section D.8 of Schedule 8.1 of the RAA grants the Company the right to establish a rate for capacity that is based on cost. AEP-Ohio notes that, by its plain language, the RAA allows an FRR Entity like AEP-Ohio to change the basis for capacity pricing to a cost-based method at any time. AEP-Ohio also notes that no party to this proceeding challenges the Commission's discretion under the RAA to establish cost-based capacity pricing as the state compensation mechanism. According to AEP-Ohio, the term "cost" as used in Section D.8 of Schedule 8.1 of the RAA refers to embedded cost. AEP-Ohio adds that its proposed cost-based capacity rate of $355.72/MW-day advances state policy objectives enumerated in Section 4928.02, Revised Code, as well as the Commission's objectives in this proceeding of promoting alternative competitive supply and retail competition, while also ensuring the Company's ability to attract capital investment to meet its FRR capacity obligations, which were set forth by the Commission in response to the FERC filing (OEG Ex. 101 at 4). With respect to promoting alternative competitive supply and retail competition, AEP-Ohio asserts that the Commission's focus should be on fairness and genuine competition, rather than on the manufacture of artificial competition through subsidization. AEP-Ohio believes that, because shopping will still occur and CRES providers will still realize a significant margin at the Company's proposed rate (Tr. XI at 2330-2333), the rate is consistent with the Commission's first objective. AEP-Ohio also believes that its proposed rate satisfies the Commission's second objective of ensuring the Company's ability to attract capital investment to meet its FRR capacity obligations. AEP-Ohio contends that its proposed rate would enable the Company to continue to attract

7 *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011).

capital and satisfy its FRR capacity obligations without harm to the Company, while providing customers with reliable and reasonably priced retail electric service as required by Section 4928.02, Revised Code. AEP-Ohio argues that cost-based capacity pricing would encourage investment in generation in Ohio and thereby increase retail reliability and affordability, as well as adequately compensate the Company for its capacity obligations as an FRR Entity.

AEP-Ohio contends that, during the period in which it remains an FRR Entity, RPM-based capacity pricing is not appropriate. As an FRR Entity, AEP-Ohio notes that it does not procure capacity for its load obligations in PJM's RPM auctions or even participate in such auctions, except to the extent that the Company has capacity that it does not need for its native load. AEP-Ohio points out that, under such circumstances, its auction participation is limited to 1,300 MW. (AEP-Ohio Ex. 105 at 8; Tr. III at 661-662.) AEP Ohio argues that, as an FRR Entity, it would not recover its capacity costs, if capacity pricing is based on RPM prices, and the difference is not made up by its SSO customers (Tr. I at 64). AEP-Ohio maintains that, because its obligations as an FRR Entity are longer and more binding reliability obligations than a CRES provider's obligations as an alternative LSE, an RPM-based price for capacity would not be compensatory or allow the Company to recover an amount even remotely approaching its embedded costs for the 2011-2012 and 2012-2013 PJM planning years, and should thus be rejected (Tr. II at 243). According to AEP-Ohio, RPM-based capacity pricing would also give CRES providers an unfair advantage over the members of the pool agreement, which purchase capacity based on embedded costs (Tr. I at 59-60), and discriminate against non-shopping customers.

Additionally, AEP-Ohio claims that RPM-based capacity pricing would cause substantial, confiscatory financial harm to the Company. According to AEP-Ohio witness Allen, the Company would earn a return on equity of 7.6 percent in 2012 and a return on equity of 2.4 percent in 2013, with a $240 million decrease in earnings between 2012 and 2013, if RPM-based capacity pricing is adopted (AEP-Ohio Ex. 104 at 3-5, Ex. WAA-1; Tr. III at 701).

Finally, AEP-Ohio notes that RPM-based capacity pricing is inappropriate because it would constitute an illegal subsidy to CRES providers in violation of Section 4928.02(H), Revised Code.

b. Staff

In its brief, Staff contends that AEP-Ohio should receive compensation from CRES providers for the Company's FRR obligations in the form of the prevailing RPM rate in the unconstrained region of PJM. Staff opposes the Company's request to establish a capacity rate that is significantly above the market rate. Staff notes that other investor-owned utilities in Ohio charge CRES providers RPM-based capacity pricing and that such pricing should, therefore, also be appropriate for AEP-Ohio. Staff further notes that the evidentiary record does not support AEP-Ohio's proposed capacity pricing of $355.72/MW-day.

c. Intervenors

All of the intervenors in this case agree that the Commission should adopt RPM-based capacity pricing as the state compensation mechanism. Many of the intervenors note that AEP-Ohio has used RPM-based capacity pricing since 2007, without incurring financial hardship or compromising service reliability for its customers. They further note that AEP-Ohio will continue to use RPM-based capacity pricing, at the Company's own election, beginning on June 1, 2015. They believe, therefore, that the Commission should adopt RPM-based capacity pricing as the state compensation mechanism for the intervening three-year period for numerous reasons, including for the sake of competition and continuity.

FES argues that RPM-based capacity pricing is the proper state compensation mechanism for AEP-Ohio. FES contends that a market-based state compensation mechanism, specifically one that adopts the RPM price as the best indicator of the market price for capacity, is required because Ohio law and policy have established and promoted a competitive market for electric generation service; RPM-based pricing is supported by sound economic principles and avoids distorted incentives for CRES providers; and AEP-Ohio's return on equity is more than sufficient under RPM-based pricing, given that the Company's analysis is based on unrealistic shopping assumptions. FES adds that, even if cost-based pricing were appropriate, AEP-Ohio has dramatically overstated its costs. FES argues that AEP-Ohio's proposed capacity pricing mechanism is not based on the costs associated with the capacity provided by AEP-Ohio to Ohio customers; includes all costs, rather than just those avoidable costs that are relevant in economic decision making; includes stranded costs that may not be recovered under Ohio law; and fails to include an appropriate offset for energy sales. FES notes that, if the Commission were to allow AEP-Ohio to charge CRES providers any rate other than the RPM-based rate, the Company would be the only capacity supplier in PJM that could charge shopping customers its full embedded costs for generation, which, according to FES, is a concept that is not found within the RAA, whereas there are numerous provisions referring to "avoidable costs."

FES believes that AEP-Ohio's proposed capacity pricing would preclude customers from receiving the benefits of competition. Specifically, FES argues that competition is state law and policy, and benefits customers; AEP-Ohio's price of $355.72/MW-day would harm competition and customers; and its proposed price would provide improper, anti-competitive benefits to the Company.

IEU-Ohio contends that AEP-Ohio has failed to demonstrate that its proposed capacity pricing mechanism is just and reasonable, as required by Section 4905.22, Revised Code. IEU-Ohio asserts that RPM-based capacity pricing is the appropriate market pricing for capacity. IEU-Ohio believes that RPM-based capacity pricing is consistent with state policy, whereas AEP-Ohio's proposed capacity pricing mechanism would unlawfully subsidize the Company's position with regard to the competitive generation business, contrary to state policy. IEU-Ohio notes that neither AEP-Ohio's status as an FRR Entity nor the pool agreement is a basis for the Company's cost-based capacity pricing mechanism. IEU-Ohio points out that AEP-Ohio used RPM-based capacity pricing from 2007 through 2011, during which time the Company was an FRR Entity and the pool agreement was in effect. IEU-Ohio further argues that AEP-Ohio's proposed cost-based capacity pricing mechanism would produce results that are not comparable to the capacity price paid by SSO customers, contrary to state law. IEU-Ohio further notes that AEP-Ohio has not identified the capacity component of its SSO rates and that it is thus impossible to determine whether the proposed capacity pricing for CRES providers would be comparable to the capacity component of its SSO rates. (IEU-Ohio Ex. 102A at 29-32, Ex. KMM-10.) Regardless of the method by which the capacity pricing mechanism is established, IEU-Ohio requests that AEP-Ohio be directed to provide details to customers and CRES providers that show how the peak load contribution (PLC) that the Company assigns to a customer corresponds with the customer's PLC recognized by PJM. IEU-Ohio contends that this information is necessary to ensure that capacity compensation is being properly applied to shopping and non-shopping customers. (IEU-Ohio Ex. 102A at 33-34.)

The Suppliers argue that a capacity rate based on AEP-Ohio's embedded costs is not appropriate under the plain language of the RAA. Citing Section D.8 of Schedule 8.1 of the RAA, the Suppliers contend that AEP-Ohio may seek a cost-based rate by making a filing at FERC under Section 205 of the FPA, but only if there is no state compensation mechanism in place. The Suppliers add that the purpose of this proceeding is to establish the appropriate state compensation mechanism and that a state compensation mechanism based on AEP-Ohio's embedded costs would be contrary to the intent of the RAA, which refers only to the avoided cost rate. The Suppliers also note that allowing AEP-Ohio to recover its embedded costs would grant the Company a higher return on equity (12.2 percent in 2013) than has been allowed for any of its affiliates in other states and that is considerably higher than what the Commission granted in the Company's last rate case (RESA Ex. 103). Finally, the Suppliers maintain that AEP-Ohio's proposed cost-based capacity pricing mechanism would preclude CRES providers from making attractive offers, could result in shopping customers subsidizing non-shopping customers, and would destroy Ohio's growing competitive retail electricity market.

The Suppliers also believe that the two-tier capacity pricing mechanism that has been in effect is inequitable and inefficient and that a single RPM-based rate should be in place for all shopping customers. The Suppliers argue that the RPM price is the most transparent, market-based price for capacity, and is necessary as part of AEP-Ohio's three-year transition to market.

OEG argues that the Commission should establish either the annual or the average RPM price for the next three PJM planning years as the price that AEP-Ohio can charge CRES providers under the state compensation mechanism for its FRR capacity obligations. OEG notes that use of the three-year average RPM price of $69.20/MW-day would mitigate some of the financial impact on AEP-Ohio from fluctuating future RPM prices and ease the Company's transition out of FRR status. OEG adds that the two-tier capacity pricing mechanism should not be continued and that a single price should be charged for all CRES providers. OEG notes that its position in this case has been guided by the Commission's twin goals, as expressed to FERC, of promoting competition, while also ensuring that AEP-Ohio has the necessary capital to maintain reliability. OEG believes that AEP-Ohio's proposed capacity pricing mechanism represents a drastic departure from past precedent that would deter shopping and undermine the benefits of retail competition, which is contrary to the Commission's goal of promoting competition. With respect to OEG's position that a three-year RPM price average could be used, AEP-Ohio notes that the concept was raised for the first time in OEG's initial brief, is without evidentiary support, and should be rejected.

OMA and OHA assert that, because the Commission has already established RPM-based capacity pricing as the state compensation mechanism, AEP-Ohio has the burden, as the entity challenging the state compensation mechanism, of proving that it is unjust and unreasonable. OMA and OHA further assert that AEP-Ohio has failed to sustain its burden. OMA and OHA believe that RPM-based capacity pricing is a just, reasonable, and lawful basis for the state compensation mechanism. According to OMA and OHA, AEP-Ohio has not demonstrated that RPM-based capacity pricing would cause substantial financial harm to the Company. OMA and OHA note that AEP-Ohio's projections are based on unrealistic and unsubstantiated shopping assumptions, with 65 percent of residential customers, 80 percent of commercial customers, and 90 percent of industrial customers switching by the end of 2012 (AEP-Ohio Ex. 104 at 4-5). OMA and OHA believe that RPM-based capacity pricing would not impact AEP-Ohio's ability to attract and invest capital, noting that the Company continues to invest capital regardless of its capacity costs for shopping customers and has no need or plan to attract or invest capital in additional capacity (IEU-Ohio Ex. 104; Tr. I at 36, 128-131; Tr. V at 868). On the other hand, OMA and OHA argue that AEP-Ohio's proposed capacity pricing mechanism would substantially harm customers and CRES providers and violate state policy, as it would significantly restrict the ability of customers to shop and enjoy savings; would unfairly deny customers access to market rates for capacity when market rates are low, and subject customers to market rates when they are high; and would harm economic development and recovery efforts. OMA and OHA urge the Commission to ensure that all customers in Ohio are able to take advantage of historically low capacity prices and have access to the lowest possible competitive electricity rates, as a means to stimulate and sustain economic growth.

OCC contends that AEP-Ohio's proposed capacity pricing mechanism should be rejected because it is contrary to the plain language of the RAA, which provides that, if a state compensation mechanism exists, its pricing prevails. According to OCC, the Commission established RPM-based capacity pricing as the state compensation mechanism in its December 8, 2010, entry. OCC notes that FERC has already rejected AEPSC's attempt to establish a formula rate for capacity in Ohio in light of the Commission's adoption of RPM-based capacity pricing as the state compensation mechanism. OCC further notes that AEP-Ohio's proposed capacity pricing mechanism is inconsistent with economic efficiency and contrary to state policy. OCC's position is that the Commission should find that RPM-based capacity pricing is appropriate, given the precedent already established by the Commission and FERC, and in light of the fact that AEP-Ohio has historically used RPM-based pricing for capacity sales to CRES providers.

NFIB urges the Commission to base AEP-Ohio's capacity compensation on RPM prices. NFIB adds that AEP-Ohio's proposed capacity pricing mechanism does not promote competition and would prevent small business owners from taking advantage of historically low market prices over the next several years. NFIB believes that AEP-Ohio would earn a healthy return on equity under RPM-based capacity pricing and that the Company has failed to establish how it would be better equipped to transition to the RPM market, if its cost-based pricing mechanism is approved.

Dominion Retail recommends that the Commission continue to employ RPM-based capacity pricing as the state compensation mechanism, as market-based pricing is fundamental to the development of a robust competitive market in AEP-Ohio's service territory. According to Dominion Retail, RPM-based capacity pricing would not require AEP-Ohio, shareholders, or SSO customers to subsidize CRES providers, as the Company contends. Dominion Retail notes that AEP-Ohio proposed cost-based capacity pricing only when it became apparent that market-based energy and capacity charges would permit CRES providers to compete effectively for customers in the Company's service territory for the first time. Dominion Retail adds that AEP-Ohio's underlying motivation is to constrain shopping and that allowing the Company to charge a cost-based capacity rate would be contrary to the state policy of promoting competition. Dominion Retail argues that Ohio law does not require that capacity pricing be based on embedded costs. Dominion Retail points out that AEP-Ohio's status as an FRR Entity does not mean that the state compensation mechanism must be based on embedded costs. Dominion Retail notes that Duke Energy Ohio, Inc. will also be an FRR Entity until mid-2015, and that it nevertheless uses RPM-based capacity pricing. Dominion Retail further notes that Amended Substitute Senate Bill No. 3 (SB 3) eliminated cost-of-service-based ratemaking for generation service. Dominion Retail asserts that AEP-Ohio is unrealistic in assuming that CRES providers would be able to compete successfully if AEP-Ohio's proposed capacity pricing is adopted. Dominion Retail points out that even AEP-Ohio witness Allen agrees that the Company's proposed capacity pricing would stifle competition in the residential market (Tr. III at 669-

670). Finally, Dominion Retail points out that AEP-Ohio's proposed cost-based capacity pricing mechanism is nowhere near the Company's capacity proposal pending in 11-346, which would provide for a capacity rate of $146/MW-day for some shopping customers and $255/MW-day for the rest. Dominion Retail contends that this fact demonstrates AEP-Ohio's willingness to provide capacity at a rate less than what it has proposed in this case and also undercuts the Company's confiscation argument.

The Schools also request that the Commission retain RPM-based capacity pricing. The Schools argue that, if AEP-Ohio's proposed capacity pricing mechanism is adopted, the rate would likely be passed through to the Ohio schools that are served by CRES providers, and that these schools would suffer rate shock in violation of Section 4928.02(A), Revised Code (Schools Ex. 101 at 9). Additionally, the Schools believe that Ohio schools that do not currently receive generation service from a CRES provider would be deprived of the opportunity to shop, in violation of Section 4928.02(C), Revised Code (Schools Ex. 101 at 10-11). Finally, the Schools contend that approval of AEP-Ohio's proposed capacity pricing mechanism would likely result in cuts to teaching and staff positions, materials and equipment, and programs, in violation of Section 4928.02(N), Revised Code (Schools Ex. 101 at 10).

Duke also contends that the Commission should adopt RPM-based capacity pricing as the state compensation mechanism, which is consistent with state policy supporting competition. Duke asserts that, pursuant to the RAA, an FRR Entity may only apply to FERC for cost-based compensation for its FRR capacity obligations, if there is no state compensation mechanism in place. According to Duke, neither the RAA nor Ohio law grants AEP-Ohio the right to recover its embedded costs. Duke notes that, under Ohio law, capacity is a competitive generation service that is not subject to cost-based ratemaking.

Exelon and Constellation assert that, if AEP-Ohio's proposed capacity pricing mechanism is approved, retail competition in the Company's service territory will be stifled and customers will bear the cost. Exelon and Constellation cite numerous reasons supporting their position that AEP-Ohio's proposal should be rejected in favor of RPM-based capacity pricing: Ohio law does not require that the state compensation mechanism be based on cost; AEP-Ohio's status as an FRR Entity does not entitle it to cost-based capacity pricing; AEP-Ohio, even as an FRR Entity, could have elected to participate in the RPM auction for 2014, rather than self-supply more expensive capacity, putting its own interests above those of customers; RPM-based capacity pricing is consistent with state policy promoting the development of competitive markets, whereas the Company's proposal is not; the Company should not be allowed to unilaterally apply better-of-cost-or-market pricing; CRES providers are captive to AEP-Ohio, given the requirement that capacity be committed more than three years in advance of delivery; Ohio law requires comparable and nondiscriminatory access to CRES and RPM-based capacity pricing is used throughout Ohio except in AEP-Ohio's service territory; and adopting RPM-based capacity pricing would avoid the need to determine an arbitrary estimate of the Company's cost of service for capacity and, in any event, SB 3 eliminated full cost-of-service analysis. Exelon and Constellation note that 11-346 is the proper forum in which to determine whether AEP-Ohio requires protection to maintain its financial integrity. Exelon and Constellation further note that they would support reasonable measures that comport with a timely transition to a fully competitive market and resolution of related issues in 11-346, if such measures are shown to be necessary.

IGS contends that RPM-based capacity pricing is the clear choice over AEP-Ohio's proposed capacity pricing mechanism. IGS points out that RPM-based capacity pricing already exists, was neutrally created, applies all over the region, is market-based, is nondiscriminatory, and provides the correct incentives to assure investment in generation resources. On the other hand, AEP-Ohio's proposal, according to IGS, was devised by the Company, for this case and this case only, returns Ohio to a cost-based generation regulatory regime, shows no relationship to short- or long-term generation adequacy, and could stifle competition. IGS notes that RPM-based capacity pricing fully comports with Ohio law in that it is market-based pricing and would support the continued development of Ohio's competitive market; would avoid subsidies and discriminatory pricing; would assure adequate resources are available to provide stable electric service; and would avoid any legal problems associated with extending the transition to competition. IGS asserts that AEP-Ohio's proposed capacity pricing would be contrary to Ohio law in that it would harm the development of competition; result in anticompetitive subsidies; and violate Ohio's transition laws. IGS also notes that AEP-Ohio's justifications for recovering embedded costs are refuted by the evidence and disregard state policy. IGS contends that RPM-based capacity pricing does not raise reliability concerns or subsidize CRES providers. IGS argues that AEP-Ohio has a fundamental disagreement with state policy. IGS notes that AEP-Ohio's judgment as to the wisdom of state policy is irrelevant, given that it has been codified by the General Assembly and must be effectuated by the Commission.

Finally, Kroger asserts that the most economically efficient price and the price that AEP-Ohio should be required to charge CRES providers for capacity is the RPM price.

d. Conclusion

Initially, the Commission notes that a state compensation mechanism, as referenced in the RAA, has been in place for AEP-Ohio for some time now, at least since issuance of the December 8, 2010, entry, which expressly adopted RPM-based capacity pricing as the state compensation mechanism for the Company during the pendency of this case. The state compensation mechanism was subsequently modified by the Commission's March 7, 2012, and May 30, 2012, entries granting AEP-Ohio's requests for interim relief. No party appears to dispute, at least in this proceeding, that the Commission has adopted a state compensation mechanism for AEP-Ohio.

Given that there is, and has continually been, a state compensation mechanism in place for AEP-Ohio from the beginning of this proceeding, the issue for our consideration is whether the state compensation mechanism, on a going-forward basis, must or should be modified such that it is based on cost. AEP-Ohio contends that the state compensation mechanism must be amended so that the Company is able to recover its embedded costs of capacity. All of the intervenors and Staff oppose AEP-Ohio's request and advocate instead that the Commission retain the RPM-based state compensation mechanism, as it was established in the December 8, 2010, entry.

Pursuant to Section 4905.22, Revised Code, all charges for service shall be just and reasonable and not more than allowed by law or by order of the Commission. In this case, AEP-Ohio asserts that its proposed compensation for its FRR capacity obligations is just and reasonable and should be adopted by the Commission. Specifically, AEP-Ohio asserts that its proposed cost-based capacity pricing is consistent with state policy, will promote alternative competitive supply and retail competition, and will ensure the Company's ability to attract capital investment to meet its FRR capacity obligations. All of the intervenors and Staff, on the other hand, recommend that market-based RPM capacity pricing should be approved as the state compensation mechanism for AEP-Ohio. As discussed above, there is a general consensus among these parties that RPM-based capacity pricing is just and reasonable, easily implemented and understood, and consistent with state policy. Staff and intervenors further agree that RPM-based capacity pricing will fulfill the Commission's stated goals of both promoting competition and ensuring that AEP-Ohio has the required capital to maintain service reliability.

As discussed above, the Commission finds that it has jurisdiction to establish a state compensation mechanism in this case pursuant to its general supervisory authority found in Sections 4905.04, 4905.05, and 4905.06, Revised Code. We further find, pursuant to our regulatory authority under Chapter 4905, Revised Code, as well as Chapter 4909, Revised Code, that it is necessary and appropriate to establish a cost-based state compensation mechanism for AEP-Ohio. Those chapters require that the Commission use traditional rate base/rate of return regulation to approve rates that are based on cost, with the ultimate objective of approving a charge that is just and reasonable consistent with Section 4905.22, Revised Code. Although Chapter 4928, Revised Code, provides for market-based pricing for retail electric generation service, those provisions do not apply because, as we noted earlier, capacity is a wholesale rather than a retail service. The Commission's obligation under traditional rate regulation is to ensure that the jurisdictional utilities receive reasonable compensation for the services that they render. We conclude that the state compensation mechanism for AEP-Ohio should be based on the Company's costs. Although Staff and intervenors contend that RPM-based capacity pricing is just and reasonable, we note that the record indicates that the RPM-based price for capacity has decreased greatly since the December 8, 2010, entry was issued, and that the adjusted RPM rate currently in effect is substantially below all estimates provided by the parties regarding AEP-Ohio's cost of capacity (AEP-Ohio Ex. 102 at 21, 22; FES Ex. 103 at 55; Staff Ex. 105 at Ex. ESM-4). The record further reflects that, if RPM-based capacity pricing is adopted, AEP-Ohio may earn an unusually low return on equity of 7.6 percent in 2012 and 2.4 percent in 2013, with a loss of $240 million between 2012 and 2013 (AEP-Ohio Ex. 104 at 3-5, Ex. WAA-1; Tr. III at 701). In short, the record reveals that RPM-based capacity pricing would be insufficient to yield reasonable compensation for AEP-Ohio's provision of capacity to CRES providers in fulfillment of its FRR capacity obligations.

However, the Commission also recognizes that RPM-based capacity pricing will further the development of competition in the market (Exelon Ex. 101 at 7; OEG Ex. 102 at 11), which is one of our primary objectives in this proceeding. We believe that RPM-based capacity pricing will stimulate true competition among suppliers in AEP-Ohio's service territory. We also believe that RPM-based capacity pricing will facilitate AEP-Ohio's transition to full participation in the competitive market, as well as incent shopping. RPM-based capacity pricing has been used successfully throughout Ohio and the rest of the PJM region and puts electric utilities and CRES providers on a level playing field (FES Ex. 101 at 50-51; FES Ex. 102 at 3). RPM-based capacity pricing is thus a reasonable means of promoting shopping in AEP-Ohio's service territory and advancing the state policy objectives of Section 4928.02, Revised Code, which the Commission is required to effectuate pursuant to Section 4928.06(A), Revised Code.

Therefore, with the intention of adopting a state compensation mechanism that achieves a reasonable outcome for all stakeholders, the Commission directs that the state compensation mechanism shall be based on the costs incurred by the FRR Entity for its FRR capacity obligations, as discussed further in the following section. However, because the record in this proceeding demonstrates that RPM-based capacity pricing will promote retail electric competition, we find it necessary to take appropriate measures to facilitate this important objective. For that reason, the Commission directs AEP-Ohio to charge CRES providers the adjusted final zonal PJM RPM rate in effect for the rest of the RTO region for the current PJM delivery year (as of today, approximately $20/MW-day), and with the rate changing annually on June 1, 2013, and June 1, 2014, to match the then current adjusted final zonal PJM RPM rate in the rest of the RTO region. Further, the Commission will authorize AEP-Ohio to modify its accounting procedures, pursuant to Section 4905.13, Revised Code, to defer incurred capacity costs not recovered from CRES provider billings during the ESP period to the extent that the total incurred capacity costs do not exceed the capacity pricing that we approve below. Moreover, the Commission notes that we will establish an appropriate recovery mechanism for such deferred costs and address any additional financial considerations in the 11-346 proceeding. We also find that AEP-Ohio should be authorized to collect carrying charges on the deferral based on the Company's weighted average cost of capital, until such time as a recovery mechanism is approved in 11-346, in order to ensure that the Company is fully compensated. Thereafter, AEP-Ohio should be authorized to collect carrying charges at its long-term cost of debt.

Additionally, the Commission directs that the state compensation mechanism that we approve today shall not take effect until our opinion and order is issued in 11-346, or until August 8, 2012, whichever is sooner. Until that time, the interim capacity pricing mechanism that we approved on March 7, 2012, and extended on May 30, 2012, shall remain in place. In further extending the interim capacity pricing mechanism, we recognize that 11-346 and the present proceeding are intricately related. In fact, AEP-Ohio has put forth an entirely different capacity pricing mechanism in 11-346 as a component of its proposed ESP. Although this case has proceeded separately so that an evidentiary record on the appropriate capacity cost pricing/recovery mechanism could be developed, there is an overlap of issues between the two proceedings. For that reason, we find that the state compensation mechanism approved today should become effective with the issuance of our order in 11-346, which will address AEP-Ohio's comprehensive rate package, including its capacity pricing proposal, or August 8, 2012, whichever occurs first.

We note that the state compensation mechanism, once effective, shall remain in effect until AEP-Ohio's transition to full participation in the RPM market is complete and the Company is no longer subject to its FRR capacity obligations, which is expected to occur on or before June 1, 2015, or until otherwise directed by the Commission.

The Commission believes that the approach that we adopt today appropriately balances our objectives of enabling AEP-Ohio to recover its costs for capacity incurred in fulfilling its FRR capacity obligations, while promoting the further development of retail competition in the Company's service territory.

3. <u>What should the resulting compensation be for AEP-Ohio's FRR capacity obligations?</u>

a. <u>AEP-Ohio</u>

AEP-Ohio's position is that the appropriate cost-based capacity price to be charged to CRES providers is $355.72/MW-day, on a merged company basis, before consideration of any offsetting energy credit. AEP-Ohio notes that the formula rate approach recommended by Company witness Pearce is based upon the average cost of serving the Company's LSE obligation load (both the load served directly by AEP-Ohio and the load served by CRES providers) on a dollar-per-MW-day basis. AEP-Ohio further notes that, because the Company supplies its own generation resources to satisfy these load obligations, the cost to provide this capacity is the actual embedded capacity cost of its generation. AEP-Ohio's formula rate template was modeled after, and modified from, the capacity portion of a FERC-approved template used to derive the charges applied to wholesale sales made by Southwestern Electric Power Company, an affiliate of the Company, to the cities of Minden, Louisiana and Prescott, Arkansas. AEP-Ohio notes that Dr. Pearce's formula rate approach is transparent and, if adopted, would be updated annually by May 31 to reflect the most current input data, most of which is publicly available and taken directly from the Company's FERC Form 1 and audited financial statements (AEP-Ohio Ex. 102 at 8). AEP-Ohio adds that its proposed formula rate template would promote rate stability and result in a reasonable return on equity of 12.2 percent in 2013, based on a capacity price of $355.72/MW-day (Tr. II at 12-25; AEP-Ohio Ex. 142 at 21-22).

AEP-Ohio contends that its proposed cost-based capacity pricing roughly approximates and is, therefore, comparable to the amount that the Company receives from its SSO customers for capacity through base generation rates (AEP-Ohio Ex. 142 at 19-20; Tr. II at 304, 350).

b. Staff

If the Commission determines that RPM-based capacity pricing is not appropriate for AEP-Ohio, Staff proposes an alternate capacity rate of $146.41/MW-day, which accounts for energy margins as well as certain cost adjustments to the Company's proposed capacity pricing mechanism. Staff notes that its alternate rate may offer more financial stability to AEP-Ohio than RPM-based capacity pricing over the next three years, and is just and reasonable unlike the Company's excessive rate proposal. Staff finds that its alternate rate would appropriately balance the interests of AEP-Ohio in recovering its embedded costs to meet its FRR capacity obligations and attracting capital investment, while also promoting alternative competitive supply and retail competition.

According to Staff, the reduction of AEP-Ohio's proposed rate of $355.72/MW-day to Staff's alternative recommendation of $146.41/MW-day is a result of removing and adjusting numerous items, including return on equity; rate of return; construction work in progress (CWIP); plant held for future use (PHFFU); cash working capital (CWC); certain prepayments, including a prepaid pension asset and the related accumulated deferred income taxes; accumulated deferred income taxes; payroll and benefits for eliminated positions; 2010 severance program cost; income tax expense; domestic production activities; payroll tax expense; capacity equalization revenue; ancillary services revenue; and energy sales margin and ancillary services receipts. In terms of the return on equity, Staff witness Smith used ten percent for CSP and 10.3 percent for OP, because these percentages were adopted by the Commission in AEP-Ohio's recent distribution rate case (Staff Ex. 103 at 12-13).[8] Staff notes that CWIP was properly excluded from rate base because AEP-Ohio has not demonstrated that the requirements of Section 4909.15 or 4928.143, Revised Code, have been met (Staff Ex. 103 at 14-15). Staff also excluded PHFFU from rate base, as the plant in

8 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively, AEP Ohio) for an Increase in Electric Distribution Rates,* Case No. 11-351-EL-AIR, *et al.*

question is not used and useful and AEP-Ohio has given no indication as to when it will become so (Staff Ex. 103 at 16). CWC was excluded by Staff because AEP-Ohio did not prepare a lead-lag study or otherwise demonstrate a need for CWC (Staff Ex. 103 at 18-21). Staff excluded AEP-Ohio's prepaid pension asset for numerous reasons, mainly because the Company did not demonstrate that it has a net prepaid pension asset and its FERC Form 1 for 2010 suggests that there is actually a net liability; pension funding levels are the result of discretionary management decisions regarding the funding of defined benefit pensions; and pension expense is typically included in the determination of CWC in a lead-lag study, which was not provided (Staff Ex. 103 at 21-31). Staff further excluded nonrecurring costs related to the significant number of positions that were permanently eliminated as a result of AEP-Ohio's severance program in 2010 (Staff Ex. 1-3 at 43-52).

AEP-Ohio responds that Mr. Smith's downward adjustments and elimination of certain costs from Dr. Pearce's calculations are fundamentally flawed in that Dr. Pearce's formula rate approach is based on a formula rate template that was approved by FERC. AEP-Ohio also counters that adjustments made by Mr. Smith to the return on equity, operations and maintenance expenses attributable to severance programs, prepaid pension assets, CWC, CWIP, and PHFFU understate the Company's costs and contradict prior orders and practices of both the Commission and FERC. With respect to the return on equity, AEP-Ohio notes that Mr. Smith's adjustment was inappropriately taken from the stipulation in the Company's recent distribution rate case and that Mr. Smith agreed that the competitive generation business is more risky than the distribution business (Staff Ex. 103 at 12-13; Tr. IX at 1991, 1993; AEP-Ohio Ex. 142 at 17). AEP-Ohio contends that the Commission should adopt a return on equity of 11.15 percent as recommended by Dr. Pearce or, at a minimum, a return on equity of 10.5 percent, which AEP-Ohio claims is consistent with a return on equity that the Commission has recently recognized for certain generating assets of the Company (AEP-Ohio Ex. 142 at 17-18). AEP-Ohio further contends that Mr. Smith's elimination of certain severance costs and prepaid pension expenses is inconsistent with the Commission's treatment of such costs in the Company's recent distribution rate case, and that the $39.004 million in severance costs should be amortized over three years (AEP-Ohio Ex. 142 at 17). AEP-Ohio argues that Mr. Smith's elimination of CWIP and CWC is inconsistent with FERC practice.

Additionally, AEP-Ohio asserts that Staff witnesses Smith and Harter failed to account for nearly $66.5 million in certain energy costs incurred by the Company, including Production-Related Administrative & General Expenses, Return on Production-Related Investments, Production-Related Depreciation Expenses, and Production-Related Income Taxes. According to AEP-Ohio, due to these trapped costs, Mr. Smith's capacity charge is understated by $20.11/MW-day on a merged company basis (AEP-Ohio Ex. 143 at 3, 5-6). AEP-Ohio witness Allen incorporated this amount in his calculation of what Staff's capacity rate would be, as modified by his recommended energy credit and cost-of-service adjustments, and reached a resulting capacity rate of $291.58/MW-day (AEP-Ohio Ex. 142 at 18; Tr. XI at 2311).

c. Intervenors

If the Commission believes that it is appropriate to consider AEP-Ohio's embedded costs, FES argues that the Company's true cost of capacity is $78.53/MW-day, after adjustments are made to reflect the removal of stranded costs and post-2001 generation investment, as well as an appropriate offset for energy sales. At most, FES contends that it should be $90.83/MW-day, if a further adjustment is made to credit back to AEP-Ohio the capacity equalization payments for the Company's Waterford and Darby plants, which were acquired in 2005 and 2007. FES also recommends that the Commission require AEP-Ohio to unbundle its base generation rate into energy and capacity components, which would ensure that the Company is charging the same price for shopping and non-shopping customers and allow customers to compare offers from CRES providers with the Company's tariff rates (FES Ex. 103 at 22).

The Suppliers note that, if the Commission finds that RPM-based capacity pricing is confiscatory or otherwise fails to compensate AEP-Ohio adequately, a nonbypassable stabilization charge, such as the rate stability rider rate proposed by the Company in 11-346, would be appropriate and should be considered in that case. OMA and OHA respond by arguing that any suggestion that rates should be raised without any justification, other than reaching a level that is high enough to ensure that CRES providers are able to compete with AEP-Ohio, tramples on customer interests and should be rejected by the Commission.

As discussed in greater detail below, OEG recommends that AEP-Ohio's capacity charge should be no higher than $145.79/MW-day, which was the RPM-based price for the 2011/2012 PJM delivery year, and only if the Commission determines that the prevailing RPM price is not sufficient compensation (OEG Ex. 102 at 9-10). OEG argues that a capacity charge of $145.79/MW-day provided a more than sufficient return on equity for AEP-Ohio, as well as fostered retail competition in its service territory (OEG Ex. 102 at 10-11). As part of this recommendation, OEG urges the Commission adopt an earnings stabilization mechanism (ESM) in the form of an annual review to gauge whether AEP-Ohio's earnings are too high or too low (OEG Ex. 102 at 15-21).

(i) Should there be an offsetting energy credit?

a) AEP-Ohio

AEP-Ohio does not recommend that the Commission adopt an energy credit offset to the capacity price, given that PJM maintains separate markets for capacity and energy (AEP-Ohio Ex. 102 at 13). AEP-Ohio witness Pearce, however, offers a recommendation for how an energy credit should be devised, if the Commission determines that an energy credit is appropriate. Dr. Pearce's template for the calculation of energy costs is derived from the same formula rate template discussed above and approved by FERC (AEP-Ohio Ex. 102 at 14). The energy credit would be calculated as the difference between the revenues that the historic load shapes for CSP and OP, including all shopping and non-shopping load, would be valued at using locational marginal prices (LMP) that settle in the PJM day-ahead market, less the cost basis of this energy (AEP-Ohio Ex. 102 at Ex. KDP-1 through KDP-5). According to Dr. Pearce, the calculation relies upon a fair and reasonable proxy for the energy revenues that could have been obtained by CSP and OP by selling equivalent generation into the market (AEP-Ohio Ex. 102 at 15). AEP-Ohio contends that, if an energy credit is used to partially offset the demand charge, it should reflect actual energy margins for 2010 in order to best match the corresponding cost basis for calculating the demand charge. Dr. Pearce recommends that energy margins from OSS that are properly attributed to capacity sales to CRES providers should be shared on a 50/50 basis between AEP-Ohio and CRES providers (AEP-Ohio Ex. 102 at 18). Additionally, Dr. Pearce recommends that any energy credit be capped at 40 percent of the capacity charge that would be applicable with no energy credit, as a means to ensure that the credit does not grow so large as to reduce greatly capacity payments from CRES providers in times of high prices (AEP-Ohio Ex. 102 at 18).

b) Staff

As discussed above, Staff recommends that AEP-Ohio's compensation for its FRR capacity obligations be based on RPM pricing. Alternatively, Staff proposes a capacity rate of $146.41/MW-day, which includes an offsetting energy credit and ancillary services credit. In calculating its proposed energy credit, Staff developed a forecast of total energy margins for AEP-Ohio's generating assets, using a dispatch market model known as AURORAxmp, which is licensed by Staff's consultant in this case, Energy Ventures Analysis, Inc. (EVA), as well as by AEP-Ohio and others (Staff Ex. 101 at 6; Tr. X at 2146, 2149; Tr. XII at 2637).

AEP-Ohio contends that Staff's black-box methodology for calculation of the energy credit is flawed in several ways and produces unrealistic and grossly overstated results. Specifically, AEP-Ohio argues that the AURORAxmp model used by Staff witnesses Harter and Medine is not well-suited for the task of computing an energy credit and that EVA implemented the model in a flawed manner through use of inaccurate and inappropriate input data and assumptions, which overstates gross energy margins for the period of June 2012 through May 2015 by nearly 200 percent (AEP-Ohio Ex. 144 at 8-25; AEP-Ohio Ex. 142 at 2-14). AEP-Ohio notes that, among other flaws, Staff's proposed energy credit understates fuel costs for coal units, understates the heat rates for gas units, overstates market prices (*e.g.*, use of zonal rather than nodal prices, use of forecasted LMP rather than forward energy prices), fails to account for the gross margins allocable to the Company's full requirements contract with Wheeling Power Company, and fails to account for the fact that the pool agreement limits the gross margins retained by the Company. AEP-Ohio argues that Company witness Allen proposed a number of conservative adjustments that should, at a minimum, be made to Staff's approach, resulting in an energy credit of \$47.46/MW-day (AEP-Ohio Ex. 142 at 4-14). AEP-Ohio adds that the documentation of EVA's approach is incomplete, inadequate, and cannot be sufficiently tested or validated; the data used in the model and the model itself cannot be reasonably verified; EVA's quality control measures are deficient; and the execution of EVA's analysis contains significant errors and has not been performed with requisite care (AEP-Ohio Ex. 144 at 13-18).

Additionally, AEP-Ohio points out that Staff's proposed energy credit wrongly incorporates OSS margins not related to capacity sales to CRES providers and also fails to properly reflect the impact of the pool agreement. Specifically, AEP-Ohio contends that, if an energy credit is adopted, it should reflect only the OSS margins attributable to energy that is freed up due to capacity sales to CRES providers. AEP-Ohio further notes that Staff inappropriately assumes that 100 percent of the margins associated with retail sales to SSO customers are available to be offset against the cost of capacity sold to CRES providers, which is inconsistent with the terms of the pool agreement, pursuant to which the Company's member load ratio share is 40 percent. AEP-Ohio believes that there is no reason to include margins associated with retail sales to SSO customers in an energy credit calculation intended to price capacity for shopping load. In accordance with Mr. Allen's recommendations, AEP-Ohio concludes that, if Staff's proposed energy credit is adopted by the Commission, it should be adjusted to \$47.46/MW-day. Alternatively, AEP-Ohio notes that Mr. Allen's proposed adjustments (AEP-Ohio Ex. 142 at 14) to Staff's energy credit could be made individually or in combination to the extent that the Commission agrees with the basis for each adjustment. AEP-Ohio adds that Company witness Nelson also offered additional options for an energy credit calculation, with the various methods converging around \$66/MW-day for the energy credit (AEP-Ohio Ex. 143 at 8, 12-13, 17). As a final option, AEP-Ohio states that the Commission could direct Staff to calculate an energy credit that is consistent with the forward prices recommended by Staff for use in the market rate option price comparison test in 11-346, which the Company believes would reduce Staff's energy credit by approximately \$50/MW-day.

c) <u>Intervenors</u>

FES argues that AEP-Ohio's formula rate should include an offset for energy-related sales or else the Company would double recover its capacity costs. FES notes that an energy credit is appropriate because AEP-Ohio recovers a portion of its fixed costs through energy-related sales for resale, and is also necessary to avoid an above-market return on equity for the Company. (FES Ex. 103 at 45-46, 49-50.) FES adds that all of AEP-Ohio's OSS revenues should be included as a credit against capacity costs and that no adjustment should be made to account for the pool agreement, given that the pool agreement could have been modified to account for retail shopping, as well as that the Company proposes to recover its embedded capacity costs both from shopping customers and off-system energy sales (FES Ex. 103 at 47; Tr. I at 29-30). At minimum, FES believes that AEP-Ohio should account for its portion of OSS revenues, after pool sharing, in its capacity price. (FES Ex. 103 at 48-49.) If RPM-based capacity pricing is not required by the Commission, FES recommends that FES witness Lesser's energy credit, which simply uses AEP-Ohio's FERC account information without adjustments to account for the pool agreement, be adopted. FES notes that Dr. Lesser determined that AEP-Ohio overstated its capacity costs by $178.1 million by failing to include an offset for energy sales.

OCC notes that it would be unjust and unreasonable for AEP-Ohio to be permitted to recover any of its embedded generation costs from customers, particularly without any offset for energy sales. OCC argues that, if the Commission adopts a cost-based capacity pricing mechanism, an energy credit that accounts for profits from OSS is warranted to ensure that AEP-Ohio does not recover embedded capacity costs from CRES providers, as well as recover some of those same costs from off-system energy sales, resulting in double recovery.

(ii) <u>Does the Company's proposed cost-based capacity pricing mechanism constitute a request for recovery of stranded generation investment?</u>

a) <u>Intervenors</u>

FES argues that SB 3 required that all generation plant investment occurring after January 1, 2001, be recovered solely in the market. FES notes that AEP-Ohio admits, in its recently filed corporate separation plan,[9] that it can no longer recover stranded costs, as the transition period for recovery of such costs is long over. FES adds that AEP-Ohio witness Pearce failed to exclude stranded costs from his calculation of capacity costs. FES points out that, pursuant to the stipulation approved by the Commission in AEP-Ohio's electric transition plan (ETP) case, the Company waived recovery of its stranded generation costs and, in any event, through depreciation accruals, has already fully recovered such costs. FES also notes that Dr. Pearce's calculation inappropriately includes costs for generation plant investments made after December 31, 2000, and also seeks to recover the costs of assets that will no longer be owned by the Company as of January 1, 2014, but will rather be owned by AEP Generation Resources.

IEU-Ohio agrees with FES that AEP-Ohio agreed to forgo any claim for stranded generation costs, which bars the Company's untimely claim to generation plant-related transition revenues. IEU-Ohio contends that AEP-Ohio seeks to impose what IEU-Ohio considers to be a lost revenue charge on CRES suppliers serving shopping customers.

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[9] *In the Matter of the Application of Ohio Power Company for Approval of Full Legal Corporate Separation and Amendment to its Corporate Separation Plan,* Case No. 12-1126-EL-UNC.

Citing Sections 4928.141, 4928.38, and 4928.40, Revised Code, as well as AEP-Ohio's agreement to forgo recovery of generation transition revenues in its ETP case (Tr. I at 49-50; FES Ex. 106; FES Ex. 107), OMA and OHA likewise contend that Ohio law prohibits the Commission from establishing a state compensation mechanism that would authorize the receipt of transition revenues or any equivalent revenues by AEP-Ohio as a means to recover its above-market capacity costs.

Kroger argues that AEP-Ohio, through its requested compensation for its FRR capacity obligations, seeks recovery of stranded generation transition costs in this case. Kroger contends that such costs must be recovered in the market and that AEP-Ohio should not be permitted to renege on the stipulation in the ETP case. Dominion Retail likewise argues that AEP-Ohio should not be permitted to violate the terms of the ETP stipulation and recover stranded above-market generation investment costs after the statutory period for such recovery has expired. Dominion Retail believes that AEP-Ohio is effectively seeking a second transition plan in this case. IGS adds that the law is meaningless if utilities may continue to require all customers to pay embedded generation costs after the transition period has ended and that approval of AEP-Ohio's proposed capacity pricing mechanism would be contrary to the statutory requirements found in Sections 4928.38, 4928.39, and 4928.40, Revised Code.

b) AEP-Ohio

AEP-Ohio responds that neither the provisions of SB 3 nor the ETP stipulation are applicable to this case. AEP-Ohio notes that the purpose of this proceeding is to establish a wholesale capacity pricing mechanism based on the Company's embedded capacity costs, as opposed to the retail generation transition charges authorized by Section 4928.40, Revised Code, which is what the Company agreed to forgo during the market development period as part of the ETP stipulation. AEP-Ohio asserts that the issue of whether the Company could recover stranded asset value from retail customers under SB 3 is a separate matter from establishing a wholesale price that permits the Company's competitors to use that same capacity. AEP-Ohio adds that a conclusion that SB 3 precludes the Company from recovering its capacity costs through a wholesale rate would conflict with the RAA and be preempted under the FPA.

(iii) Should OEG's alternate proposal be adopted?

a) OEG

OEG recommends that AEP-Ohio's capacity pricing mechanism should be based on RPM prices. As an alternative recommendation, if the Commission determines that AEP-Ohio's capacity pricing should be higher than the prevailing RPM price, OEG suggests that the capacity price should be no higher than \$145.79/MW-day, which was the RPM-based price for the 2011/2012 PJM delivery year. OEG believes that such price has proven effective in providing a more than sufficient return on equity for AEP-Ohio, while still fostering retail competition in the Company's service territory. (OEG Ex. 102 at 10-11). Additionally, OEG witness Kollen recommends that the Commission adopt an ESM to ensure that AEP-Ohio's earnings are neither too high nor too low and instead are maintained within a Commission-determined zone of reasonableness. OEG believes that such an approach is appropriate, given the significant uncertainty regarding both the proper compensation for AEP-Ohio's FRR capacity obligations and the impact of various charges on the Company's earnings. In particular, Mr. Kollen suggests that an earnings bandwidth be established, with a lower threshold return on equity of seven percent and an upper threshold return on equity of 11 percent. If AEP-Ohio's earnings fall below the lower threshold of seven percent, then the Company would be allowed to increase its rates through a nonbypassable ESM charge sufficient to increase its earnings to the seven percent level. If earnings exceed the upper threshold of 11 percent, then AEP- Ohio would return the excess earnings to customers through a nonbypassable ESM credit. If AEP-Ohio's earnings are within the earnings bandwidth, there would be no rate changes other than those that operate to recover defined costs such as through the fuel adjustment clause. Finally, Mr. Kollen notes that the Commission would have the discretion to make modifications as circumstances warrant. (OEG. Ex. 102 at 15-21.) OEG believes that its recommended lower threshold is reasonable as confirmed by the recent actual earned returns of the AEP East affiliates, which averaged 6.8 percent in 2010 and 7.8 percent in 2011 (OEG Ex. 102 at 13). Additionally, AEP-Ohio's adjusted return in 2011 was 11.42 percent, just above its suggested upper threshold (OEG Ex. 102 at Ex. LK-3). Mr. Kollen explained that AEP-Ohio's earned return on equity would be computed in the same manner as under the significantly excessive earnings test (SEET) of Section 4928.143(F), Revised Code, although he believes that OSS margins should be included in the computation to be consistent with certain other parties' recommended approach of accounting for energy margins in the calculation of a cost-based capacity price (OEG Ex. 102 at 10, 15, 18; Tr. VI at 1290.)

b) AEP-Ohio

AEP-Ohio urges the Commission to reject OEG's alternate proposal. AEP-Ohio notes that the upper threshold of 11 percent is significantly lower than any SEET threshold previously applied to the Company and that the proposal would essentially render the statutory SEET obsolete. According to AEP-Ohio, the Commission is without jurisdiction to impose another, more stringent, excessive earnings test on the Company. AEP-Ohio also argues that OEG's proposal would preclude the Company from exercising its right under Section D.8 of Schedule 8.1 of the RAA to establish a cost-based compensation method. AEP-Ohio believes that Mr. Kollen's excessive earnings test would offer no material protection to the Company from undercompensation of its costs incurred to furnish capacity to CRES providers, and that the test would be difficult to administer, cause prolonged litigation on an annual basis, and create substantial uncertainty for the Company and customers.

d. Conclusion

As discussed above, the Commission believes that AEP-Ohio's capacity costs, rather than RPM-based pricing, should form the basis of the state compensation mechanism established in this proceeding. Upon review of the considerable evidence in this proceeding, we find that the record supports compensation of $188.88/MW-day as an appropriate charge to enable AEP-Ohio to recover its capacity costs for its FRR obligations from CRES providers. We also find that, as a means to encourage the further development of retail competition in AEP-Ohio's service territory, the Company should modify its accounting procedures to defer the difference between the adjusted RPM rate currently in effect and AEP-Ohio's incurred capacity costs, to the extent that such costs do not exceed the capacity charge approved today. We believe that this approach successfully balances the Commission's objectives and the interests of the many parties to this proceeding.

The record reflects a range in AEP-Ohio's cost of capacity from a low of $78.53/MW-day, put forth by FES, to the Company's high of $355.72/MW-day, as a merged entity, with Staff and OEG offering recommendations more in the middle of the range (AEP-Ohio Ex. 102 at 21; FES Ex. 103 at 55; Staff Ex. 105 at Ex. ESM-4; OEG Ex. 102 at 10-11). The Commission finds that Staff's determination of AEP-Ohio's capacity costs is reasonable, supported by the evidence of record, and should be adopted as modified in this order. Initially, we note that no party other than AEP-Ohio appears to seriously challenge Staff's recommended cost-based capacity pricing mechanism in this case. Additionally, we do not believe that AEP-Ohio has demonstrated that its proposed charge of $355.72/MW-day falls within the zone of reasonableness, nor do we believe that FES' proposed charge of $78.53/MW-day would result in reasonable compensation for the Company's FRR capacity obligations.

The Commission believes that the approach used by Staff is an appropriate method for determining AEP-Ohio's capacity costs. In deriving its recommended charge, Staff followed its traditional process of making reasonable adjustments to AEP-Ohio's proposed capacity pricing mechanism, which is based on the capacity portion of a formula rate template approved by FERC for one of the Company's affiliates and was modified by the Company for use in this case with data from its FERC Form 1 (Staff Ex. 103 at 10-12; AEP-Ohio Ex. 102 at 8, 9). As AEP-Ohio notes, FERC-approved formula rates are routinely used by the Company's affiliates in other states (AEP-Ohio Ex. 102 at 8; Tr. II at 253). Given that compensation for AEP-Ohio's FRR capacity obligations from CRES providers is wholesale in nature, we find that AEP-Ohio's formula rate template is an appropriate starting point for determination of its capacity costs. From that starting point, Staff made a number of reasonable adjustments to AEP-Ohio's proposal in order to be consistent with the Commission's ratemaking practices. Staff further adjusted AEP-Ohio's proposed capacity pricing to account for margins from off-system energy sales and ancillary receipts (Staff Ex. 101 at 4). We agree with Staff, FES, and OCC that an offset for energy-related sales is necessary to ensure that AEP-Ohio does not over recover its capacity costs through recovery of its embedded costs as well as OSS margins (FES Ex. 103 at 45-46).

AEP-Ohio takes issue with the adjustments made by Staff witness Smith as well as with EVA's calculation of the energy credit. The Commission believes that the adjustments to AEP-Ohio's proposed capacity pricing mechanism that were made by Staff witness Smith are, for the most part, reasonable and consistent with our ratemaking practices in Ohio. With regard to AEP-Ohio's prepaid pension asset, however, we agree with the Company that Mr. Smith's exclusion of this item was inconsistent with Staff's recommendation in the Company's recent distribution rate case (AEP-Ohio Ex. 129A; AEP-Ohio Ex. 129B), as well as with our treatment of pension expense in other proceedings.[10] We see no reason to vary our practice in the present case and, therefore, find that AEP-Ohio's prepaid pension asset should not have been excluded. The result of our adjustment increases Staff's recommendation by $3.20/MW-day (AEP-Ohio Ex. 142 at 16, Ex. WAA-R7). Similarly, with respect to AEP-Ohio's severance program costs, we find that Mr. Smith's exclusion of such costs was inconsistent with their treatment in the Company's distribution rate case. Amortization of the severance program costs over a three-year period increases Staff's recommendation by $4.07/MW-day. (AEP-Ohio Ex. 142 at 16-17.) Further, upon consideration of the arguments with respect to the appropriate return on equity, we find that AEP-Ohio's recommendation of 11.15 percent is reasonable and should be adopted. As AEP-Ohio notes, Staff's recommended return on equity was solely based on the negotiated return on equity in the Company's distribution rate case (Staff Ex. 103 at 12-13), which has no precedential effect pursuant to the express terms of the stipulation adopted by the Commission in that case. Our adoption of a return on equity of 11.15 percent increases Staff's recommendation by $10.09/MW-day (AEP-Ohio Ex. 142 at 17). We also agree with AEP-Ohio that certain energy costs were trapped in Staff's calculation of its recommended capacity charge, in that Staff witness Smith regarded such costs as energy related and thus excluded them from his calculations, while EVA disregarded them in its determination of the energy credit. Accordingly, we find that Staff's recommendation should be increased by $20.11/MW-day to account for these trapped costs. (AEP-Ohio Ex. 143 at 5-6.)

Additionally, the Commission finds, on the whole, that Staff's recommended energy credit, as put forth by EVA, is reasonable. AEP-Ohio raises a number of arguments as to why Staff's energy credit, as calculated by EVA, should not be adopted by the Commission. In essence, AEP-Ohio fundamentally disagrees with the methodology used by EVA. Although we find that EVA's methodology should be adopted, we agree with AEP-Ohio

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10 *See, e.g., In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices, and for Tariff Approvals,* Case No. 07-551-EL-AIR, *et al.*, Opinion and Order (January 21, 2009), at 16.

that EVA's calculation should have accounted for the Company's full requirements obligation to serve Wheeling Power Company, a point that Staff did not dispute in its briefs. As AEP-Ohio witness Allen testified, the Company's sales to Wheeling Power Company reduce the quantity of generation available for OSS and thus should have been reflected in EVA's calculation of OSS margins. (AEP-Ohio Ex. 142 at 10-11, Ex. WAA-R5). The result of this adjustment reduces Staff's recommended energy credit by $5/MW-day (AEP-Ohio Ex. 142 at 11, Ex. WAA-R5) to $147.41/MW-day. The overall effect of this adjustment, in combination with the adjustments for AEP-Ohio's prepaid pension asset, severance program costs, return on equity, and trapped costs, results in a capacity charge of $188.88/MW-day.

We note that a charge of $188.88/MW-day is fairly in line with OEG's alternate recommendation that the capacity charge not exceed $145.79/MW-day, which was the adjusted RPM rate in effect in the prior PJM delivery year that recently concluded (OEG Ex. 102 at 10-11). The close proximity of our approved charge with OEG's recommendation is further confirmation that the approved charge falls within the zone of reasonableness. Additionally, as OEG notes, a charge of $145.79/MW-day afforded AEP-Ohio an adequate return on equity. In 2011, AEP-Ohio earned a per books, unadjusted return of 10.21 percent, or an adjusted return of 11.42 percent after adjustments for plant impairment expense and certain non-recurring revenue (OEG Ex. 102 at 11, Ex. LK-3). At the same time, the capacity charge was not so high as to hinder retail competition in AEP-Ohio's service territory. In the first quarter of 2011, the RPM price was $220.96/MW-day and only 7.1 percent of AEP-Ohio's total load had switched to a CRES provider. However, by the end of the year, with a lower RPM price of $145.79/MW-day in effect, shopping had significantly increased in AEP-Ohio's service territory, with 19.10 percent of the Company's total load having elected to shop (specifically, 5.53 percent of the residential class, 33.88 percent of the commercial class, and 18.26 percent of the industrial class). (OEG Ex. 102 at 11.) We expect that the approved compensation of $188.88/MW-day for AEP-Ohio's FRR capacity obligations will likewise ensure that the Company earns an appropriate return on equity, as well as enable the further development of competition in the Company's service territory.

Although AEP-Ohio criticizes Staff's proposed capacity pricing mechanism for various reasons, the Commission finds that none of these arguments has merit. First, as a general matter, AEP-Ohio argues that Staff failed to follow FERC practices and precedent. We agree with Staff that FERC has different requirements for items such as CWC and CWIP than are found in Ohio. As Staff notes, the outcome of this case should not be dictated by FERC practices or precedent but should instead be consistent with Ohio ratemaking principles. Although FERC practices and precedent may be informative in some instances, the Commission is bound by Ohio law in establishing an appropriate state compensation mechanism. In response to AEP-Ohio's specific argument regarding the exclusion of CWIP, Staff explained that Section 4909.15(A)(1), Revised Codes, requires that construction projects must be at least 75 percent complete in order to qualify for a CWIP allowance and that AEP-Ohio failed to demonstrate compliance with this requirement.

As previously mentioned above, AEP-Ohio raises numerous concerns regarding Staff's proposed energy credit and offered the rebuttal testimony of Company witness Meehan in an effort to critique EVA's testimony. Upon review of all of the testimony, the Commission finds that it is clear that the dispute between AEP-Ohio and Staff amounts to a fundamental difference in methodology in everything from the calculation of gross energy margins to accounting for operation of the pool agreement. AEP-Ohio claims that Staff's inputs to the AURORAxmp model result in an overstated energy credit, while Staff argues that the Company's energy credit is far too low. Essentially, AEP-Ohio and Staff have simply offered two quite different approaches in their attempt to forecast market prices for energy. The Commission concludes that AEP-Ohio has not shown that the process used by Staff was erroneous or unreasonable. We further find that the approach put forth by EVA is a proper means of determining the energy credit and produces an energy credit that will ensure that AEP-Ohio does not over recover its capacity costs.

Accordingly, we adopt Staff's proposed energy credit, as modified above to account for AEP-Ohio's full requirements contract with Wheeling Power Company, and find that a capacity charge of $188.88/MW-day is just, reasonable, and should be adopted. The Commission agrees with AEP-Ohio that the compensation received from CRES providers for the Company's FRR capacity obligations should reasonably and fairly compensate the Company and should not significantly undermine the Company's ability to earn an adequate return on its investment. The Commission believes that, by adopting a cost-based state compensation mechanism for AEP-Ohio, with a capacity charge of $188.88/MW-day, in conjunction with the authorized deferral of the Company's incurred capacity costs, to the extent that the total incurred capacity costs do not exceed $188.88/MW-day not recovered from CRES provider billings reflecting the adjusted RPM-based price, we have accomplished those objectives, while also protecting the interests of all stakeholders.

<u>FINDINGS OF FACT AND CONCLUSIONS OF LAW:</u>

(1) AEP-Ohio is a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of this Commission.

(2) On November 1, 2010, AEPSC, on behalf of AEP-Ohio, filed an application with FERC in FERC Docket No. ER11-1995, and on November 24, 2010, refiled its application, at the direction of FERC, in FERC Docket No. ER11-2183. The application proposed to change the basis for compensation for capacity costs to a cost-based mechanism and included proposed formula rate

templates under which AEP-Ohio would calculate its capacity costs under Section D.8 of Schedule 8.1 of the RAA.

(3) By entry issued on December 8, 2010, the Commission initiated an investigation in the present case to determine the impact of AEP-Ohio's proposed change to its capacity charge.

(4) The following parties were granted intervention in this proceeding: OEG, IEU-Ohio, OCC, OPAE, OMA, OHA, Direct Energy, Constellation, FES, Duke, Exelon, IGS, RESA, Schools, OFBF, Kroger, NFIB, Dominion Retail, AICUO, Grove City, and OCMC.

(5) On September 7, 2011, the ESP 2 Stipulation was filed by AEP-Ohio, Staff, and other parties to resolve the issues raised in the consolidated cases, including the present case.

(6) On December 14, 2011, the Commission adopted the ESP 2 Stipulation with modifications.

(7) By entry on rehearing issued on February 23, 2012, the Commission revoked its prior approval of the ESP 2 Stipulation, finding that the signatory parties had not met their burden of demonstrating that the stipulation, as a package, benefits ratepayers and the public interest.

(8) By entry issued on March 7, 2012, the Commission approved, with modifications, AEP-Ohio's proposed interim capacity pricing mechanism.

(9) A prehearing conference occurred on April 11, 2012.

(10) A hearing commenced on April 17, 2012, and concluded on May 15, 2012. AEP-Ohio offered the direct testimony of five witnesses and the rebuttal testimony of three witnesses. Additionally, 17 witnesses testified on behalf of various intervenors and three witnesses testified on behalf of Staff.

(11) Initial briefs and reply briefs were filed on May 23, 2012, and May 30, 2012, respectively.

(12) By entry issued on May 30, 2012, the Commission approved an extension of AEP-Ohio's interim capacity pricing mechanism through July 2, 2012.

(13) The Commission has jurisdiction in this matter pursuant to Sections 4905.04, 4905.05, and 4905.06, Revised Code.

(14) The state compensation mechanism for AEP-Ohio, as set forth herein, is just and reasonable and should be adopted.

ORDER:

It is, therefore,

ORDERED, That IEU-Ohio's motion to dismiss this case be denied. It is, further,

ORDERED, That the motion for permission to appear *pro hac vice instanter* filed by Derek Shaffer be granted. It is, further,

ORDERED, That the state compensation mechanism for AEP-Ohio be adopted as set forth herein. It is, further,

ORDERED, That AEP-Ohio be authorized to defer its incurred capacity costs not recovered from CRES provider billings to the extent the total incurred capacity costs do not exceed $188.88/MW-day. It is, further,

ORDERED, That the interim capacity pricing mechanism approved on March 7, 2012, and extended on May 30, 2012, shall remain in place until the earlier of August 8, 2012, or such time as the Commission issues its opinion and order in 11-346, at which point the state compensation mechanism approved herein shall be incorporated into the rates to be effective pursuant to that order. It is, further,

ORDERED, That nothing in this opinion and order shall be binding upon this Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further, ORDERED, That a copy of this opinion and order be served upon all parties of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter w/ concurrence

Cheryl L. Roberto

Lynn Slaby w/ concurrence

SJP/GNS/sc

Entered in the Journal

JUL 02 2012

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	))))	Case No. 10-2929-EL-UNC

CONCURRING OPINION
OF COMMISSIONERS ANDRE T. PORTER AND LYNN SLABY

The majority opinion and order balances the interests of consumers, suppliers, and AEP-Ohio. It provides certainty for consumers and suppliers by resolving questions about whether there will be a competitive electricity market in the AEP-Ohio territory, specifically, and across this state, generally. It does so by establishing a state compensation mechanism pursuant to which competitive retail electric suppliers have access to RPM-based market capacity pricing, which will encourage competition among those suppliers, resulting in the benefit to consumers of the lowest and best possible electric generation rates in the AEP-Ohio territory.

Moreover, it recognizes the important function and commitment of AEP-Ohio as a fixed resource requirement entity having dedicated capacity to serve consumers in its service territory. However, these resources are not without cost. Accordingly, the order allows AEP-Ohio to receive its actual costs of providing the capacity through the deferral mechanism described therein, which we have determined, after thorough consideration of the record in this proceeding, to be $188.88/MW-day. This result is a fair balance of all interests because rather than subjecting AEP-Ohio to RPM capacity rates that were derived from a market process in which AEP-Ohio did not participate, the order allows AEP-Ohio to recover the costs of the agreement to which it was a participant—dedicating its capacity to serve consumers in its service territory. Our opinion of this result, in this case, should not be misunderstood as it relates to RPM; *by joining the majority opinion, we do not, in any way, agree to any description of RPM-based capacity rates as being unjust or unreasonable.*

Finally, while we prefer to have the state compensation mechanism effective as of today, we join with the majority in setting the effective date of August 8, 2012, or to coincide with our as-yet unissued opinion and order in Docket No. 11-346-EL-SSO, whichever is earlier. In an attempt to balance the deferral authorization created in this proceeding and the anticipated mechanism to be considered as part of Docket No. 11-346-EL-SSO to administer the deferral, we agree that it is equitable to tie the decision being made in this order to that in 11-346-EL-SSO. However, we caution that the balance is only achieved within an expeditious resolution of the 11-346-EL-SSO docket by August 8, 2012.

Andre T. Porter

Lynn Slaby

ATP/LS/sc

Entered in the Journal

JUL 02 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	))))	Case No. 10-2929-EL-UNC

CONCURRING AND DISSENTING OPINION
OF COMMISSIONER CHERYL L. ROBERTO

I join my colleagues in updating the state compensation method for the Fixed Resource Requirement from that originally adopted implicitly in AEP-Ohio's first ESP case, Case No. 08-917-EL-SSO, *et al.*, and explicitly in this matter to a cost-based rate of $188.88/MW-day.

I depart from the majority, however, in the analysis of the nature of the Fixed Resource Requirement and, as a result, the basis for the Commission's authority to update the state compensation method for the Fixed Resource Requirement.

Additionally, I dissent from those portions of the majority opinion creating a deferral of a portion of the authorized cost-based Fixed Resource Requirement rate adopted today.

What is a Fixed Resource Requirement?

In order to assure that the transmission system is reliable, PJM requires any one who wishes to transmit electricity over the system to their customers[1] to provide reliability assurance that they have the wherewithal - or *capacity* - to use the transmission system without crashing it or otherwise destabilizing it for everyone else.[2] The protocols for making this demonstration are contained in the Reliability Assurance Agreement. Each transmission system user must show that they possess Capacity Resources sufficient to meet their own needs plus a margin for safety. These Capacity Resources may include a combination of generation facilities, demand resources, energy efficiency, and Interruptible

1 These transmission users are known as a "Load Serving Entity" or "LSE." LSE shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. *Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, PJM Interconnection,* L.L.C., Rate Schedule FERC No. 44 (effective date May 29, 2012) (hereinafter Reliability Assurance Agreement), Section 1.44.

2 Section 5, Capacity Resource Commitment, PJM Open Access Transmission Tariff (effective date June 8, 2012), at 2395-2443.

Load for Reliability.[3] Capacity Resources may even include a transmission upgrade.[4] The Fixed Resource Requirement is nothing more than an enforceable agreement that for a finite period one transmission user will demonstrate on behalf of other transmission users within a specified territory that sufficient Capacity Resources exist to meet all of their respective reliability needs. During this period, the transmission user offering to provide the Fixed Resource Requirement is the sole authorized means by which a transmission user who opts to use this service may demonstrate the adequacy of their Capacity Resources.[5] This demonstration is embodied in a Fixed Resource Requirement Capacity Plan that describes a portfolio of the generation, demand resources, energy efficiency, Interruptible Load for Reliability, and transmission upgrades it plans to use to meet the Capacity Resource requirements for the territory.[6] The Ohio Supreme Court has noted that regional transmission organizations, such as PJM, provide transmission services through FERC approved rates and tariffs.[7] Thus, the Fixed Resource Requirement is a commitment to provide a transmission service pursuant to the tariffs filed by PJM with FERC.

As established in this matter, AEP-Ohio has committed to provide the Fixed Resource Requirement for all transmission users offering electricity for sale to retail customers within the footprint of its system. No other entity may provide this service during the term of the current AEP-Ohio Fixed Resource Requirement Capacity Plan.

<u>Commission Authority to Establish State Compensation Method for the Fixed Resource Requirement Service</u>

Chapter 4928, Revised Code, defines "retail electric service" to mean any service involved in the supply or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For purposes of Chapter 4928, Revised Code, retail electric service includes, among other things, transmission service.[8] As discussed, *supra*, AEP-Ohio is the sole provider of the Fixed Resource Requirement service for other transmission users operating within its footprint until the expiration of its obligation on June 1, 2015. As such, this service is a "noncompetitive retail electric service" pursuant to Sections 4928.01(A)(21) and 4928.03, Revised Code. This Commission is empowered to set rates for noncompetitive retail electric services. While PJM could certainly propose a tariff for FERC adoption directing PJM to

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3 Reliability Assurance Agreement, Schedule 6, Procedures for Demand Resources, ILR, and Energy Efficiency.

4 Reliability Assurance Agreement, Schedule 8.1, Section D.6.

5 Reliability Assurance Agreement, Section 1.29 defines the Fixed Resource Requirement Capacity Plan to mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

6 Reliability Assurance Agreement, Section 7.4, Fixed Resource Requirement Alternative.

7 *Ohio Consumers' Counsel v. PUCO*, 111 Ohio St.3d. 384, 856 N.E.2d 940 (2006).

8 Section 4928.01(A)(27), Revised Code.

establish a compensation method for Fixed Resource Requirement service, it has opted not to do so in favor of a state compensation method when a state chooses to establish one. When this Commission chooses to establish a state compensation method for a noncompetitive retail electric service, the adopted rate must be just and reasonable based upon traditional cost-of-service principles.

This Commission previously established a state compensation method for AEP-Ohio's Fixed Resource Requirement service within AEP-Ohio's initial ESP. AEP-Ohio received compensation for its Fixed Resource Requirement service through both the provider of last resort charges to certain retail shopping customers and a capacity charge levied on competitive retail providers that was established by the three-year capacity auction conducted by PJM.[9] Since the Commission adopted this compensation method, the Ohio Supreme Court reversed the authorized provider of last resort charges,[10] and the auction value of the capacity charges has fallen precipitously, as has the relative proportion of shoppers to non-shoppers.

I agree with the majority that the Commission is empowered pursuant to its general supervisory authority found in Sections 4905.04, 4905.05, and 4905.06, Revised Code to establish an appropriate rate for the Fixed Resource Requirement service. I also agree that pursuant to regulatory authority under Chapter 4905, Revised Code, as well as Chapter 4909, Revised Code a cost-based compensation method is necessary and appropriate. Additionally, I find that because the Fixed Resource Requirement is a noncompetitive retail electric service, the Commission must establish the appropriate rate based upon traditional cost of service principles. Finally, I find specific authority within Section 4909.13, Revised Code, for a process by which the Commission may cause further hearings and investigations and may examine into all matters which may change, modify, or affect any finding of fact previously made. Given the change in circumstances since the Commission adopted the initial state compensation for AEP-Ohio's Fixed Resource Requirement service, it is appropriate for the Commission to revisit and adjust that rate to reflect current circumstances as we have today.

"Deferral"

In prior cases, this Commission has levied a rate or tariff on a group of customers but deferred collection of revenues due from that group until a later date. In this instance, the majority proposes to establish a rate for the Fixed Resource Requirement service provided

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9 *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets,* Case No. 08-917-EL-SSO, *et al.*, Opinion and Order (March 18, 2009), Entry on Rehearing (July 23, 2009); *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* Case No. 10-2929-EL-UNC, Entry (December 8, 2010).

10 *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512 (2011).

by AEP-Ohio to other transmission users but then to discount that rate such that the transmission users will never pay it. The difference between the authorized rate and that paid by the other transmission users will be booked for future payment not by the transmission users but by retail electricity customers. The stated purpose of this device is to promote competition.

As an initial matter, I am not convinced on the record before us that competition has suffered sufficiently or will suffer sufficiently during the remaining term of the Fixed Resource Requirement as the result of the state compensation method to warrant intervention in the market. If it did, the Commission could consider regulatory options such as shopping credits granted to the consumers to promote consumer entry into the market. With more buyers in the market, in theory, more sellers should enter and prices should fall. The method selected by the majority, however, attempts to entice more sellers to the market by offering a significant, no-strings-attached, unearned benefit. This policy choice operates on faith alone that sellers will compete at levels that drop energy prices while transferring the unearned discount to consumers. If the retail providers do not pass along the entirety of the discount, then consumers will certainly and inevitably pay twice for the discount today granted to the retail suppliers. To be clear, unless every retail provider disgorges 100 percent of the discount to consumers in the form of lower prices, shopping consumers will pay more for Fixed Resource Requirements service than the retail provider did. This represents the first payment by the consumer for the service. Then the deferral, with carrying costs, will come due and the consumer will pay for it all over again – plus interest.

I find that that the mechanism labeled a "deferral" in the majority opinion is an unnecessary, ineffective, and costly intervention into the market that I cannot support. Thus, I dissent from those portions of the majority opinion adopting this mechanism.

Cheryl L. Roberto

Cheryl L. Roberto

CLR/sc

Entered in the Journal JUL 02 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider.	)))))	Case No. 10-1454-EL-RDR

FINDING AND ORDER

The Commission finds:

(1) Ohio Power Company (OP or the Company) is a public utility and an electric light company within the definitions of Sections 4905.02 and 4905.03(A)(3), Revised Code, and, as such, is subject to the jurisdiction of this Commission pursuant to Sections 4905.04, 4905.05, and 4905.06, Revised Code.

(2) On October 1, 2010, OP filed an application requesting that the Commission approve the closure of Unit 5 of the Philip Sporn Generating Station (Sporn Unit 5) to the extent such approval is required by Sections 4905.20 and 4905.21, Revised Code. OP explains that the plant is located on the Ohio River and is comprised of five generation units placed into service between 1950 and 1960. OP states that it owns Sporn Units 2, 4, and 5, while Appalachian Power Company, which operates the plant, owns Sporn Units 1 and 3. According to OP, Sporn Unit 5 is an early supercritical unit that currently has a winter capability of 450 megawatts.

OP further requests that the Commission simultaneously approve the establishment of a Plant Closure Cost Recovery Rider (PCCRR) to collect the costs associated with the closure of Sporn Unit 5. As proposed by OP, the nonbypassable distribution rider would enable the Company to recover incurred closure costs as of December 2010, which include the unamortized plant balance remaining on OP's books (approximately $56.1 million) and unique materials and supplies that cannot be used at other plants (approximately

$2.6 million). The proposed PCCRR would also permit OP to recover closure costs incurred after December 2010, which are expected to include any legally required asset retirement obligations (such as asbestos removal, fly ash pond closure, and disposal of transformer-rectifier set fluids) and any net salvage to be incurred related to the Sporn Unit 5 assets (such as unique materials and supplies). OP requests accounting authority to record the future costs in a regulatory asset/liability account, with such costs being included in the PCCRR when incurred. OP further requests that a weighted average cost of capital carrying charge on the future cost deferrals be recovered through the PCCRR. Finally, OP proposes that the PCCRR rate be implemented outside of the rate caps established in the case approving, as modified, the Company's electric security plan (ESP 1) for 2009 through 2011 (ESP 1 Case).[1]

If the Commission should determine that it is appropriate to mitigate the rate impact of the PCCRR, OP alternatively requests that the Commission amortize recovery of the Sporn Unit 5 closure costs over a 36-month period, with carrying charges being included over the extended recovery period.

(3) In support of its application, OP states:

(a) Effective December 10, 2007, a New Source Review (NSR) Consent Decree, resolving all complaints related to NSR requirements filed against American Electric Power (AEP) and its affiliates, including OP, was entered with the United States Department of Justice. As part of the NSR Consent Decree, Sporn Unit 5 is required to be retired, repowered, or retrofitted by December 31, 2013. AEP's plan to comply with the NSR Consent Decree included retirement of Sporn Unit 5 at the end of 2013.

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1 *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan,* Case No. 08-918-EL-SSO, Opinion and Order (March 18, 2009) (ESP 1 Order).

(b) Aside from the planned retirement at the end of 2013, AEP's integrated resource planning process had projected the retirement and removal of Sporn Unit 5 as a capacity resource in 2010. As a result, AEP did not bid Sporn Unit 5 into the PJM Interconnection, LLC (PJM) base residual capacity auction for the 2010-2011 planning year, which was conducted in early 2008. Sporn Unit 5 was thus no longer a PJM capacity resource as of June 1, 2010, but was expected to be available to produce power for the PJM energy market through the end of 2013.

(c) During the period prior to OP's ESP 1 application, revenues from Sporn Unit 5, less all operating and maintenance expenses, resulted in an approximately $36.3 million contribution to other costs of the Company and were expected to continue to be available to produce such contributions during the term of ESP 1. Current projections based on economic conditions, however, indicate operating losses of $8.4 million and $6.8 million for 2011 and 2012, respectively, for Sporn Unit 5. The results for 2013 are expected to be similar. For this reason, OP plans to close Sporn Unit 5 earlier than previously expected, contingent upon Commission approval.

(d) In the ESP 1 Case, the Commission approved OP's request for authority to come before the Commission during the term of ESP 1 to determine the appropriate treatment for accelerated depreciation and other net early closure costs in the event it becomes necessary to close a generation plant earlier than previously anticipated.[2] OP submits that the ESP 1 Order thus specifically contemplated the Company's recovery of early closure costs.

2 ESP 1 Order at 52-53.

(e) Noting that Sporn Unit 5 has served and benefitted OP's ratepayers during the life of the asset, the Company asserts that shareholders should not be expected to absorb the early closure costs, which represent dollars invested during a regulatory regime in which OP was permitted to recover all prudently incurred costs, including plant closure costs. OP further contends that it would have absorbed such early closure costs, if it had been permitted to transition to market-based generation rates by 2006, as originally contemplated under Amended Substitute Senate Bill 3 (SB 3). Therefore, OP believes that it is reasonable under the circumstances for the Company to recover the costs associated with the early closure of Sporn Unit 5.

(4) Motions to intervene were filed on various dates by Ohio Partners for Affordable Energy (OPAE); Industrial Energy Users-Ohio (IEU-Ohio)[3]; Ohio Consumers' Counsel (OCC); Ohio Environmental Council (OEC); Ohio Energy Group (OEG); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly, Walmart); Sierra Club of Ohio (Sierra Club); and OMA Energy Group (OMAEG). No memoranda contra were filed. The Commission finds that the motions to intervene are reasonable and should be granted.

(5) On October 5, 2010, and December 17, 2010, respectively, motions for admission *pro hac vice* were filed on behalf of David C. Rinebolt for OPAE and Holly Rachel Smith for Walmart.[4] No memoranda contra were filed. The Commission finds that the motions for admission *pro hac vice* are reasonable and should be granted.

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3 On February 18, 2011, IEU-Ohio filed a motion to consolidate this case with numerous other cases pending before the Commission. This finding and order does not address IEU-Ohio's motion to consolidate.

4 The motions to practice *pro hac vice* were filed prior to the recent amendment of Rule XII, Section 2 of the Government of the Bar of Ohio, which provides new procedures for requesting *pro hac vice* admission.

(6) By entry of March 9, 2011, the Commission established a procedural schedule for the filing of comments and reply comments.

(7) Upon the filing of its application, OP provided PJM, as required, an advance 90-day notification of the planned closure of Sporn Unit 5, contingent upon Commission approval. Subsequently, on March 30, 2011, OP filed notice with the Commission that it was informed by PJM on October 29, 2010, that PJM had identified no reliability violations resulting from the proposed shutdown and that Sporn Unit 5 could be deactivated at any time from PJM's perspective. OP further reported that Monitoring Analytics, LLC, which is known as the Market Monitoring Unit in PJM's Open Access Transmission Tariff, notified the Company on February 1, 2011, that it had identified no market power issue with respect to the proposed closure of Sporn Unit 5.

(8) In accordance with the procedural schedule established in this case, timely initial comments were filed by IEU-Ohio, OEG, OCC, OMAEG, OPAE, Walmart, and Staff on April 8, 2011.[5]

(9) On April 14, 2011, OP filed a motion for a four-day extension of the deadline for reply comments, which was granted by the attorney examiner by entry issued April 15, 2011.

(10) On April 20, 2011, OCC filed supplemental comments, as well as a motion for leave to file supplemental comments *instanter*, pursuant to Rule 4901-1-12, Ohio Administrative Code. In support of its motion, OCC states that it seeks to file supplemental comments in light of a recent decision of the Supreme Court of Ohio that impacts this case. Further, OCC notes that its supplemental comments were included with the motion in order to afford the other parties the opportunity to respond in their reply comments. OCC, therefore, concludes that granting its motion will not adversely affect a substantial right of any party. No memoranda contra OCC's motion were

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5 OCC, OEC, and Sierra Club also provided comments on OP's application along with their motions to intervene. Subsequently, OP filed comments in response to OCC and OEC. The Commission will consider these filings in addition to the initial comments and reply comments filed in accordance with the procedural schedule.

filed. The Commission finds that OCC's motion for leave to file supplemental comments *instanter* is reasonable and should be granted.

(11) Timely reply comments were filed by OP on April 21, 2011, and by FirstEnergy Solutions Corp. (FES), IEU-Ohio, and OPAE on April 22, 2011.

Staff Comments

(12) In its comments, Staff argues that the Commission should not approve OP's request for recovery of costs associated with the closure of Sporn Unit 5, as there is no statutory basis for recovery of such costs. Staff asserts that Amended Substitute Senate Bill 221 (SB 221) contains no provision allowing for recovery of costs related to the closure of a generating unit. Staff points out that, although Section 4928.143(B)(2)(c), Revised Code, provides for the establishment of a nonbypassable surcharge for the life of a generating facility if specific conditions are met, those conditions have not been met with respect to Sporn Unit 5, because it was constructed prior to January 1, 2009, not competitively bid, and not subject to a determination of need by the Commission. Staff concludes that the only provision under current law that would permit the sort of charge sought by OP does not apply under the circumstances.

Staff further argues that OP's requested relief would conflict with the mandatory policy provision of Section 4928.02(H), Revised Code, which requires the Commission to avoid subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates. Staff notes that generation service is a competitive retail electric service in Ohio pursuant to Section 4928.03, Revised Code; OP seeks to establish a nonbypassable charge that would be collected from all distribution customers; and competitive suppliers cannot collect closure costs from their customers. Staff contends that OP would have a competitive advantage in its generation service business if it were permitted to collect closure costs.

(13) In its reply comments, FES agrees with Staff. OP, however, responds that Section 4928.143, Revised Code, enables the Commission to allow recovery of plant closure costs. Citing Section 4928.143(C)(1), Revised Code, OP argues that the only determination for the Commission to make with respect to a proposed electric security plan (ESP) is whether it is more favorable in the aggregate as compared to the expected results of a market rate offer. OP also disputes Staff's position that SB 221 does not address plant retirement. OP points to Section 4928.143(B)(2)(c), Revised Code, which provides that the Commission may consider, as applicable, the effects of any decommissioning, deratings, and retirements before it authorizes a surcharge pursuant to that provision. OP asserts that this provision is an integral part of attempting to encourage construction of new generating capacity in Ohio. OP submits that, in order to effectively address such construction in a comprehensive manner as envisioned by the General Assembly, the Commission should address the entire investment cycle, including retirement of existing plants, or else capacity will not be built in Ohio. In further support of its request, OP notes that Section 4928.143(B)(2)(d), Revised Code, authorizes recovery of carrying costs and deferrals.

Additionally, OP asserts that, in the ESP 1 Order, the Commission explicitly permitted the Company to request recovery of early plant closure costs during the term of ESP 1.[6] Because no party challenged the Commission's determination on this point, OP states that it is a final and non-appealable order. OP contends that the Commission retains discretion to grant or deny its request, but that no party can reasonably claim that the Commission lacks the legal ability to implement this provision of ESP 1. OP believes that the argument that SB221 precludes recovery of closure costs is a collateral attack on the ESP 1 Order.

Further, OP points out that the Commission has recently represented in comments to the United States Environmental Protection Agency that certain proposed environmental regulations would accelerate the retirement of coal-fired

6 ESP 1 Order at 52-53.

generating plants and that the cost of premature retirements would have a direct impact on rates, in part due to amortization and other closure costs. OP argues that the Commission's comments undercut Staff's position in this case and instead support the Company's policy arguments regarding its request for recovery of early closure costs. OP believes that the Commission has already indicated that ratepayers will pay for early plant retirements and that the Commission may not now claim that such a result is unlawful or unreasonable.

(14) In its comments, Staff further notes that, during the market development period from 2000 through 2005, OP had the opportunity to receive transition revenues, including revenues associated with regulatory assets, to assist the Company in making the transition to a fully competitive retail electric generation market. Staff points out that revenues associated with regulatory assets were to end no later than December 31, 2010, pursuant to Section 4928.40(A), Revised Code, and that, in any event, OP elected to forgo recovery of any stranded generation transition charges pursuant to the stipulation reached in its electric transition plan case.[7]

(15) In its reply comments, FES agrees with Staff, adding that, even if OP's request were timely, the Company has failed to meet the criteria of Section 4928.39, Revised Code. According to FES, these criteria would require that the closure costs be prudently incurred; legitimate, net, verifiable, and directly allocable to retail electric generation service; and unrecoverable in a competitive market; and also require that the Company otherwise be entitled an opportunity to recover the costs.

For its part, OP replies that its request for recovery of the net book value of the plant and other closure costs is not the same as a request for recovery of stranded generation investment. OP further notes that, if it had been permitted to transition to market rates by 2006, it could have absorbed its early plant

7 *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues,* Case No. 99-1729-EL-ETP, *et al.*, Opinion and Order (September 28, 2000), at 15-18.

closure costs through market prices. Because OP was not permitted to transition to market-based generation pricing, the Company submits that it is reasonable under the circumstances to recover its early plant closure costs. OP also maintains that current law allows the Commission to authorize recovery of the Company's early plant closure costs. OP concludes that arguments regarding recovery of stranded investment costs are neither relevant nor dispositive in light of changed factual and legal circumstances.

(16) Additionally, Staff argues that OP has already been compensated for the costs that it seeks to recover, as Sporn Unit 5 should have been fully depreciated in 2010, based on the depreciation rates established in Case No. 94-996-EL-AIR.[8] According to Staff, these rates included 17 percent closure costs and an escalator of 3.6 percent each year to account for increased costs over time.

(17) In reply, OP disagrees with Staff that the Company's investment in Sporn Unit 5 has been full recovered, noting that depreciation rates established more than 15 years ago should not be used to override the Company's accounting books. OP asserts that Staff's position relies on outdated information and does not conform to established regulatory accounting and ratemaking principles regarding updating depreciation rates when circumstances change. OP admits that some partial adjustment to recovery of future closure costs may be appropriate, given that at least a portion of the closure costs may have been reflected in the previously authorized rates. OP contends that it is nevertheless entitled to recovery of the net book value, which is driven by approximately $70 million in capital plant additions that occurred after the distribution rate case in 1994. OP maintains that the closure costs reflected in its depreciation rates substantially underestimated the actual closure costs that apply to Sporn Unit 5, in light of the dramatic intervening increase in environmental regulations that apply to coal-burning power plants.

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8 *In the Matter of the Application of Ohio Power Company for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Electric Service and Related Matters*, Case No. 94-996-EL-AIR, *et al.*, Opinion and Order (March 23, 1995), at 36-37.

(18) Finally, Staff notes that, in a recent case, the Commission denied a request for recovery of expenses related to several retired generation facilities, rejecting Ohio Edison Company's claim that the plants remained assets of the electric distribution utility, although they were no longer used for generation.[9] OP replies that the case cited by Staff is inapplicable, as the retired generation facilities did not support the distribution service being priced in the case.

Intervenor Comments

Walmart

(19) Walmart argues that, if the Commission determines that the PCCRR is appropriate, it should be bypassable for customers taking generation service from a competitive supplier, because it would be inconsistent with cost-of-service principles to impose OP's generation costs on such customers. In its reply comments, OPAE disagrees, contending that the costs associated with the closure of Sporn Unit 5 were incurred in the past, prior to shopping in OP's service territory.

(20) Walmart further contends that the charge for the PCCRR should be calculated based on the annual kilowatt demand for customer classes with demand meters. OPAE disagrees, asserting that generation in wholesale markets is priced on a per kilowatt hour basis and that cost recovery should follow the market.

(21) Finally, Walmart states that the Commission should accept OP's offer to mitigate the rate impact of the PCCRR by amortizing recovery of closure costs over a 36-month period. OPAE again disagrees, noting that OP's customers are already facing substantial fuel cost deferrals. OPAE suggests that the deferral should be amortized over a single year or the Commission should deny recovery of carrying charges and

9 *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices, and for Tariff Approvals,* Case No. 07-551-EL-AIR, *et al.*, Opinion and Order (January 21, 2009), at 14.

amortize recovery over an appropriate period to be determined by the Commission.

OPAE

(22) OPAE argues that, as a result of the deregulation of electric utilities pursuant to SB 3, ratepayers have no legal responsibility for plant closure costs, just as they have no claim on the output of Sporn Unit 5, which OP may utilize as it sees fit. According to OPAE, the fact that Sporn Unit 5 was once used and useful in providing service to OP's distribution customers is no longer relevant because that former regulatory regime no longer exists. OPAE asserts that customers are no longer responsible for financing the generation owned by any utility; rather, they are responsible only for paying for generation at a price set through the market or an ESP. OPAE notes that no provision was made in ESP 1 for the recovery of extraordinary costs such as for the early closure of a plant. In response, OP contends that SB 221 imposed a hybrid form of re-regulation, which includes cost-based rate adjustments in an ESP that are more akin to single issue ratemaking using traditional regulatory principles.

(23) Like Staff, OPAE also points to the fact that retail electric generation is a competitive retail electric service under Section 4928.03, Revised Code, and argues that charging customers for OP's business decision to close Sporn Unit 5 would run afoul of the prohibition against anticompetitive subsidies found in Section 4928.02(H), Revised Code.

(24) Finally, OPAE argues that OP has already been compensated for plant closure costs by way of its recovery of regulatory transition costs during the market development period.

OMAEG

(25) In its comments, OMAEG asserts that OP does not cite any legal authority that would permit recovery of plant closure costs. With respect to OP's argument that Sporn Unit 5 has served ratepayers during the life of the asset and that it would thus be unreasonable to require shareholders to absorb the closure costs, OMAEG states that this argument may be

appropriate under cost-based regulation but that such regulation no longer determines generation rates.

(26) OMAEG also argues that OP has failed to provide evidence of the offsetting positive value of the remainder of its generation fleet, as addressed by the Commission in the ESP 1 Case.[10] Finally, OMAEG contends that OP has been fairly compensated by its customers, citing the Commission's review of the Company's annual earnings for 2009.[11]

<u>OEG</u>

(27) OEG argues that OP cites no statutory provision in support of its request for cost recovery. OEG contends that OP's request to recover depreciation on the undepreciated remainder of Sporn Unit 5 should be denied as it relates to a rate base and regulatory regime that no longer exist. OEG notes that ESP 1 was approved without regard to cost of service.

(28) OEG further asserts that Sporn Unit 5 does not represent a stranded cost for which OP should be compensated and that the time for recovery of such costs is past. OEG believes that OP's attempt to recover the undepreciated value of Sporn Unit 5 from ratepayers is inconsistent with the stipulation in the Company's electric transition plan case, pursuant to which OP agreed that it would not impose lost generation charges on switching customers during the market development period.[12] OEG also maintains that the plant closure costs are generation costs, which should thus not be assessed to shopping customers. In its reply comments, FES agrees with OEG on these points.

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10 ESP 1 Order at 53.

11 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code,* Case No. 10-1261-EL-UNC, Opinion and Order (January 11, 2011), at 22-23.

12 *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues,* Case No. 99-1729-EL-ETP, *et al.*, Opinion and Order (September 28, 2000), at 15-18.

(29) Finally, OEG argues that, if OP is permitted to recover plant closure costs, the Commission will have established a poor precedent that other electric utilities will seek to rely on and that utility rates and shopping will be adversely affected.

OCC

(30) OCC argues that OP should not be permitted to recover plant closure costs because such costs are not recoverable under an ESP. OCC points out that Section 4928.143(B)(2), Revised Code, does not authorize recovery of closure costs for plants that existed before SB 3 was enacted. Additionally, OCC asserts that OP is not entitled to recovery of such costs based on its receipt of regulatory asset transition revenues pursuant to Sections 4928.38 and 4928.40, Revised Code, which more than fully compensated the Company for closure costs of uneconomic plants. OCC maintains that, in receiving transition revenues, OP has forgone any cost recovery after the market development period, which has now ended.

(31) As an additional ground for denying recovery of plant closure costs, OCC states that OP retains, pursuant to ESP 1, all of the profits from off-system sales associated with its nonjurisdictional units, such as Sporn Unit 5, which benefits its shareholders. OCC further argues that OP should show that the value of the rest of its fleet does not offset the loss associated with Sporn Unit 5 before it is permitted to collect closure costs, as addressed by the Commission in the ESP 1 Case.[13] In its reply comments, FES agrees with OCC that OP should offset its profits from its generation fleet and off-system sales. OP responds, however, that OCC improperly attempts to adjust the balance achieved by the package deal adopted in the ESP 1 Order.

(32) Finally, OCC points out that, even if OP were requesting recovery of plant closure costs during the cost-of-service regulatory regime that existed prior to SB 3, it would be unlikely that such cost recovery would be permitted pursuant to Section 4909.15(A), Revised Code, given that Sporn Unit 5 is

[13] ESP 1 Order at 53.

no longer used and useful. OCC notes that the Commission rarely permitted utilities to collect plant closure costs under cost-of-service ratemaking. OP replies that traditional, cost-based regulation principles support its recovery of early plant closure costs. Under such principles, OP contends that, in order to recover any net book value, including additions, on retired property, the net book value of the retired asset, which is included in accumulated depreciation, is included in the next depreciation study in the next rate case and recovered in future rates. OP notes that it is a routine matter of utility accounting and ratemaking that plant-in-service is retired and replaced. OP argues that the Commission should follow these established regulatory accounting and ratemaking principles and authorize recovery of its early plant closure costs.

(33) In its supplemental comments, OCC argues that the Supreme Court of Ohio recently held that, pursuant to Section 4928.143(B)(2), Revised Code, an ESP may include only the items listed in the section.[14] In light of this decision, OCC contends that OP's request for recovery of plant closure costs should be denied, as such costs are not listed within the section. In their reply comments, FES, OPAE, and IEU-Ohio agree with OCC. IEU-Ohio notes that OP has identified no provision under Section 4928.143(B)(2), Revised Code, that allows recovery of plant closure costs. OP responds that the Court's decision cannot be retroactively applied to modify a portion of the ESP 1 Order that was not challenged on rehearing and appeal. According to OP, neither OCC nor the Commission can use the Court's limited remand with respect to the allowance of environmental carrying charges under Section 4928.143(B)(2), Revised Code, to open up other aspects of ESP 1, which were not the subject of rehearing and appeal.

<u>IEU-Ohio</u>

(34) IEU-Ohio comments that neither SB 221 nor ESP 1 provides a basis for cost recovery. Specifically, IEU-Ohio points out that Section 4928.143, Revised Code, provides no legal basis for recovery of plant closure costs. Regarding the ESP 1 Order,

14 *In re Application of Columbus S. Power Co.* (2011), 128 Ohio St.3d 512.

IEU-Ohio states that, although the Commission offered OP the opportunity to request recovery of plant closure costs, the Commission did not address in the order whether such costs are in fact recoverable. IEU-Ohio argues that, even under cost-of-service regulation, OP's request would be denied pursuant to Section 4909.15(A), Revised Code, because Sporn Unit 5 is not used and useful.

(35) IEU-Ohio further asserts that OP's right to recover stranded costs is long over and that the Company agreed to forgo recovery of stranded generation costs during the market development period pursuant to the stipulation in its electric transition plan case.[15]

(36) Finally, IEU-Ohio contends that OP has failed to show an economic basis for recovery of its closure costs. Although OP reports that Sporn Unit 5 is being operated at a loss, IEU-Ohio notes that the Company does not argue that these operational losses are causing financial distress, nor could it successfully make such an argument given the Commission's review of its annual earnings for 2009.[16]

OEC

(37) OEC argues that recovery of plant closure costs should only be permitted if the generation will be replaced with energy efficiency or alternative energy resources and that cost recovery in the amount requested may not be appropriate if the shutdown of Sporn Unit 5 does not produce air quality or other consumer and environmental benefits.

(38) In response, OP states that it is illogical to presume, from a resource planning perspective, that an equal amount of capacity will need to be replaced upon the retirement of Sporn

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15 *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case No. 99-1729-EL-ETP, *et al.*, Opinion and Order (September 28, 2000), at 15-18.

16 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Opinion and Order (January 11, 2011), at 22-23.

Unit 5. OP contends that the retirement of a given amount of megawatts of capacity does not automatically mean replacement of the same amount of megawatts during the immediate timeframe of the retirement, given that projected load growth or decline is a major factor that drives the need for new capacity. Further, OP argues that it is unreasonable to condition recovery of plant closure costs on the deployment of an equal amount of new alternative energy resource capacity.

Sierra Club

(39) Sierra Club notes that it supports the accelerated closure of Sporn Unit 5, but questions how a 50-year-old plant continues to carry unamortized debt for which ratepayers are responsible.

Conclusion

The Commission has reviewed OP's application, as well as the comments, supplemental comments, and reply comments filed by the parties and Staff. First, OP requests that the Commission approve the closure of Sporn Unit 5 to the extent such approval is required by Sections 4905.20 and 4905.21, Revised Code. Upon consideration of this request, the Commission concludes that the closure of Sporn Unit 5 is not subject to our approval. Pursuant to Sections 4928.03 and 4928.05(A)(1), Revised Code, retail electric generation service is a competitive retail electric service and, therefore, not subject to Commission regulation, except as otherwise provided in Chapter 4928, Revised Code. Just as the construction and maintenance of an electric generating facility are fundamental to the generation component of electric service,[17] we find that so too is the closure of an electric generating facility. Additionally, although there are exceptions in Section 4928.05(A)(1), Revised Code, that permit Commission regulation of competitive services in some circumstances, the enumerated statutory exceptions do not include Sections 4905.20 and 4905.21, Revised Code, which otherwise govern applications to abandon or close certain facilities.

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[17] *Indus. Energy Users-Ohio v. Pub. Util. Comm.* (2008), 117 Ohio St.3d 486 (finding that the classification of a proposed electric generation facility as a distribution-ancillary service, rather than a generation service, was contrary to law).

Further, although Section 4928.17(E), Revised Code, expressly prohibits the sale or transfer of any generating asset owned by an electric distribution utility in the absence of prior Commission approval, we find no similar provision in Chapter 4928, Revised Code, with respect to the closure of generating assets. Accordingly, the closure of Sporn Unit 5 is not subject to approval by the Commission and we thus decline to rule on OP's request for approval of the plant shutdown.

(40) OP also requests approval of a rider to collect the costs associated with the closure of Sporn Unit 5. As discussed above, Section 4928.05(A)(1), Revised Code, generally prohibits Commission regulation of retail electric generation service. However, that section expressly provides that it does not limit the Commission's authority under Sections 4928.141 to 4928.144, Revised Code. Pursuant to one such section, specifically Section 4928.143(B), Revised Code, the Commission is authorized to approve an ESP, which must contain provisions relating to the supply and pricing of electric generation service and may include certain other components. Pursuant to that section, the Commission approved ESP 1 for 2009 through 2011, and recently approved OP's new ESP that took effect on January 1, 2012.[18]

In the ESP 1 Order, we approved OP's request to come before the Commission to determine the appropriate treatment for accelerated depreciation and other net early closure costs in the event the Company finds it necessary to close a generation plant earlier than otherwise expected, as is the case with Sporn Unit 5.[19] In its application and reply comments, OP argues that the Commission specifically contemplated the Company's recovery of early closure costs in the ESP 1 Order. The Commission disagrees. Although we approved OP's request for authority to come before the Commission during the term of ESP 1 to determine the appropriate treatment for accelerated depreciation and other net early closure costs, nothing in the

18 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 11-346-EL-SSO, *et al.*, Opinion and Order (December 14, 2011).

19 ESP 1 Order at 52-53.

ESP 1 Order contemplated the Company's recovery of early closure costs or passed upon the legality of such costs, as OP suggests. Rather, the Commission only approved what the Company requested, which was essentially to postpone the issue and address it in a future application.

Having now reviewed that application and the comments in the present case, the Commission finds that there is no statutory basis upon which to grant recovery of the closure costs for Sporn Unit 5. As Staff and most of the intervenors note, the costs associated with the closure of Sporn Unit 5 do not fall within any of the provisions of Section 4928.143, Revised Code. Although OP implies that a broad interpretation of Section 4928.143(B)(2)(c), Revised Code, is warranted, that section provides for the establishment of a nonbypassable surcharge for the life of an electric generating facility, only if certain criteria are met. Upon consideration of these criteria, we find that Section 4928.143(B)(2)(c), Revised Code, does not authorize recovery of costs associated with the closure of Sporn Unit 5. Sporn Unit 5 was constructed long ago and, therefore, was not newly used and useful on or after January 1, 2009, as required by the statute. Neither was Sporn Unit 5 sourced through a competitive bid process or subject to a determination of need by the Commission, which are additional criteria found in Section 4928.143(B)(2)(c), Revised Code.

Although Section 4928.143(B)(2)(c), Revised Code, provides that the Commission may consider the effects of any decommissioning, deratings, and retirements, the Commission is permitted to do so only before a surcharge is authorized pursuant to that section, rather than under any circumstances. We agree with OP that the nonbypassable surcharge authorized in Section 4928.143(B)(2)(c), Revised Code, is a way in which to encourage construction of new generating capacity in the state, and that the entire investment cycle, including retirement, is important. We cannot agree, however, that any provision of Section 4928.143, Revised Code, authorizes recovery of the closure costs for Sporn Unit 5, or that the only determination for the Commission to make with respect to a proposed ESP is whether it is more favorable in the aggregate than the expected results of a market rate offer. The Commission must also determine whether the costs to be recovered under the ESP are authorized by statute.[20] With respect to the closure costs for Sporn Unit 5, we find no statutory basis within Section 4928.143, Revised Code, or anywhere else in the Revised Code.

Additionally, the Commission notes that OP's recovery of the closure costs would be contrary to the state policy found in Section 4928.02(H), Revised Code. That policy requires the Commission to avoid subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service. OP seeks to establish a nonbypassable charge that would be collected from all distribution customers by way of the PCCRR. Approval of such a charge would effectively allow the Company to recover competitive, generation-related costs through its noncompetitive, distribution rates, in contravention of the statute. Accordingly, we find that OP's request for cost recovery should be denied.

(41) In light of the Commission's finding that the closure of Sporn Unit 5 is not subject to our approval, and that there is no statutory basis for recovery of the closure costs, we find no need to hold a hearing in this matter and conclude that OP's application should be dismissed.

It is, therefore,

ORDERED, That the motions to intervene filed by various parties be granted. It is, further,

ORDERED, That the motions for admission *pro hac vice* filed on behalf of David C. Rinebolt and Holly Rachel Smith be granted. It is, further,

ORDERED, That OCC's motion for leave to file supplemental comments *instanter* be granted. It is, further,

ORDERED, That OP's application be dismissed. It is, further,

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20 *In re Application of Columbus S. Power Co.* (2011), 128 Ohio St.3d 512.

ORDERED, That a copy of this finding and order be served upon all parties of record in this case.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

SJP/sc

Entered in the Journal

JAN 11 2012

Betty McCauley

Betty McCauley
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan.	)	Case No. 11-346-EL-SSO Case No. 11-348-El-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

OPINION AND ORDER

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The Commission, considering the above-entitled applications, and the record in these proceedings, hereby issues its opinion and order in these matters.

APPEARANCES:

Steven T. Nourse, Matthew J. Satterwhite, and Yazen Alami, American Electric Power Service Corporation, One Riverside Plaza, 29th Floor, Columbus, Ohio 43215-2373, and Porter, Wright, Morris & Arthur, LLP, by Daniel R. Conway and Christen Moore, 41 South High Street, Columbus, Ohio 43215, on behalf of Ohio Power Company.

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Boehm, Kurtz & Lowry, by Michael L. Kurtz, Kurt J. Boehm and Jody Kyler, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

Taft, Stettinius & Hollister, LLP, by Mark S. Yurick and Zachary D. Kravitz, 65 East State Street, Suite 1000, Columbus, Ohio 43215-4213, on behalf of The Kroger Company.

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Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Lija Kaleps-Clark, and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, and Eimer, Stahl, Klevorn & Solberg, LLP, by David Stahl and Scott Solberg, 224 South Michigan Avenue, Suite 1100, Chicago, Illinois 60604, on behalf of Exelon Generation Company, Constellation NewEnergy, Inc., and Constellation Energy Commodities Group, Inc.

Ice Miller, LLP, by Christopher L. Miller, Gregory J. Dunn, and Asim Z. Haque, 250 West Street, Columbus, Ohio 43215, on behalf of the Association of Independent Colleges and Universities of Ohio, the city of Hillsboro, the city of Grove City and the city of Upper Arlington.

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Bricker & Eckler, LLP, by Thomas J. O'Brien, 100 South Third Street, Columbus, Ohio 43215-4291, and Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Ohio Hospital Association.

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Joseph V. Maskovyak and Michael Smalz, Ohio Poverty Law Center, 555 Buttles Avenue, Columbus, Ohio 43215, on behalf of Appalachian Peace and Justice Network.

Keating, Muething & Klekamp PLL, by Kenneth P. Kreider, One East Fourth Street, Suite 1400, Cincinnati, Ohio 45202 and Holly Rachel Smith, HITT Business Center, 3803 Rectortown Road, Marshall, Virginia 20115, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

SNR Denton US, LLP, by Emma F. Hand, Daniel D. Barnowski, and Thomas Millar, James Rubin, 1301 K Street NW, Suite 600 East Tower, Washington, D.C. 20005, on behalf of Ormet Primary Aluminum Corporation.

Bricker & Eckler, by Christopher L. Montgomery, Matthew Warnock, and Terrence O'Donnell, 100 South Third Street, Columbus, Ohio 43215-4291, and Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215-3620, on behalf of Paulding Wind Farm II, LLC.

Gregory J. Poulos, 471 East Broad Street, Suite 1520, Columbus, Ohio 43215, on behalf of EnerNOC Inc.

William, Allwein & Moser, by Christopher J. Allwien, 1373 Grandview Avenue, Suite 212, Columbus, Ohio 43212, on behalf of Natural Resources Defense Council.

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Bailey Cavalieri, LLC, by Dane Stinson, 10 West Broad Street, Columbus, Ohio 43215, on behalf of Ohio Association of School Business Officials, Ohio School Boards Association, Buckeye Association of School Administrators, and Ohio Schools Council.

Chad A. Endsley, 280 North High Street, P.O. Box 182383, Columbus, Ohio 43218, on behalf of the Ohio Farm Bureau Federation.

Buckley King, by Deim N. Kaelber, 10 West Broad Street, Suite 1300, Columbus, Ohio 43215, on behalf of Ohio Restaurant Association.

Elizabeth Watts and Rocco D'Ascenzo, 139 East Fourth Street, Cincinnati, Ohio 45202 and Eberly McMahon, LLC, by Robert A. McMahon, 2321 Kemper Lane, Suite 100, Cincinnati, Ohio 45206, on behalf of Duke Energy Ohio, Inc.

Amy B. Spiller and Jeanne W. Kingery, 139 East Fourth Street, Cincinnati, Ohio 43215, and Thompson Hine, LLP, by Philip B. Sineneng, 41 South High Street, Suite 1700, Columbus, Ohio 43215, on behalf of Duke Energy Retail Sales and Duke Energy Commercial Asset Management Inc.

Charles Howard and Sarah Bruce, 655 Metro Place South, Suite 270, Dublin, Ohio 43017, on behalf of Ohio Automobile Dealers Association.

Judi L. Sobecki, 1065 Woodman Drive, Dayton, Ohio 45432, on behalf of Dayton Power and Light Company.

Kegler, Brown, Hill & Ritter, LPA, by Roger P. Sugarman, 65 East State Street, Suite 1800, Columbus, Ohio 43215, on behalf of National Federation of Independent Business - Ohio Chapter.

Thompson Hine, LLP, by Carolyn S. Flahive, Stephanie Chmiel, and Michael Dillard, 41 South High Street, Suite 1700, Columbus, Ohio 43215, on behalf of Border Energy Electric Services, Inc.

The Behal Law Group, LLC, by Mr. Jack D'Aurora, 501 South High Street, Columbus, Ohio 43215, on behalf of University of Toledo Innovation Enterprises Corporation.

Hahn, Loeser & Parks, LLP, by Randy Hart, 200 Huntington Building, Cleveland, Ohio 44114, on behalf of Summit Ethanol, LLC d/b/a POET Biorefining-Leipsic and Fostoria Ethanol, LLC d/ b/a POET Biorefining-Fostoria.

Jay E. Jadwin, 155 West Nationwide Blvd., Suite 500, Columbus, Ohio 43215, on behalf of AEP Retail Energy Partners, LLC.

Matthew Cox Law, Ltd., by Matthew Cox, 4145 St. Theresa Boulevard, Avon, Ohio 44011, on behalf of the Council of Smaller Enterprises.

Williams, Allwein & Moser, by Todd M. Williams, Two Maritime Plaza, Toledo, Ohio 43604, on behalf of the Ohio Business Council for a Clean Economy.

Dickstein Shapiro LLP, by Larry F. Eisenstat, Richard Lehfeldt, and Robert L. Kinder, 1825 Eye St. NW, Washington, D.C. 20006, on behalf of CPV Power Development, Inc.

OPINION:

I. HISTORY OF THE PROCEEDINGS

A. First Electric Security Plan

On March 18, 2009, the Commission issued its opinion and order regarding Columbus Southern Power Company's (CSP) and Ohio Power Company's (OP) (jointly, AEP-Ohio or the Companies) application for an electric security plan (ESP 1 Order) in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO. The ESP 1 Order was appealed to the Supreme Court of Ohio (Court). On April 19, 2011, the Court affirmed the ESP Order in numerous respects, but remanded the proceedings to the Commission. The Commission issued its order on remand on October 3, 2011. In the order on remand, the Commission found that AEP-Ohio should be authorized to continue its recovery of incremental capital carrying costs incurred after January 1, 2009, on past environmental investments (2001-2008) that were not previously reflected in the Companies' existing rates prior to the ESP 1 Order. In addition, the Commission found that the provider of last resort (POLR) charges authorized by the ESP 1 Order were not supported by the record on remand, and directed the Companies to eliminate the amount of the provider of last resort (POLR_ charges authorized in the ESP Order and file revised tariffs consistent with the order on remand.

B. Initial Proposed Electric Security Plan

On January 27, 2011, AEP-Ohio filed the instant application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. This application is for approval of an electric security plan (ESP 2) in accordance with Section 4928.143, Revised Code. As filed, AEP-Ohio's SSO application for ESP 2 would commence on January 1, 2012, and continue through May 31, 2014.

The following parties were granted intervention by entries dated March 23, 2011, and July 8, 2011: Industrial Energy Users-Ohio (IEU), Duke Energy Retail Sales, LLC (Duke Retail), Ohio Energy Group (OEG), Ohio Hospital Association (OHA), Ohio Consumers' Counsel (OCC), Ohio Partners for Affordable Energy (OPAE),[1] The Kroger Company (Kroger), FirstEnergy Solutions Corporation (FES), Paulding Wind Farm II LLC (Paulding), Appalachian Peace and Justice Network (APJN), Ohio Manufacturers' Association Energy Group (OMAEG), AEP Retail Energy Partners LLC (AEP Retail), Distributed Wind Energy Association (DWEA),[2] PJM Power Providers Group (P3), Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.

1 Subsequently, OPAE filed a motion to withdraw from the ESP 2 proceedings and the request granted in the Commission's December 14, 2011 Order.

2 On August 4, 2011, DWEA filed a motion to withdraw from the ESP 2 proceedings. DWEA's request to withdraw was granted in the December 14, 2011 Order.

(Constellation), COMPETE Coalition (Compete), Natural Resources Defense Council (NRDC), The Sierra Club (Sierra), city of Hilliard, Ohio (Hilliard), Retail Energy Supply Association (RESA), Exelon Generation Company, LLC (Exelon), city of Grove City, Ohio (Grove City), Association of Independent Colleges and Universities of Ohio (AICUO), Wal-Mart Stores East, LP and Sam's East, Inc., (Wal-Mart), Dominion Retail, Inc. (Dominion Retail), Environmental Law and Policy Center (ELPC), Ohio Environmental Council (OEC), Ormet Primary Aluminum Corporation (Ormet) and EnerNOC, Inc. (EnerNOC).

On September 7, 2011, numerous parties (Signatory Parties) to the ESP 2 proceedings filed a Joint Stipulation and Recommendation (Stipulation). The Stipulation proposed to resolve the ESP 2 cases as well as a number of other related AEP-Ohio matters pending before the Commission.[3] The evidentiary hearing in the ESP 2 cases was consolidated with the related proceedings for the sole purpose of considering the Stipulation. On December 14, 2011, the Commission issued its Opinion and Order, concluding that the Stipulation, as modified by the order, should be adopted and approved. As part of the December 14, 2011, Order, the Commission approved the merger of CSP with and into OP, with OP as the surviving entity.[4]

Several applications for rehearing of the Commission's December 14, 2011, Order in the ESP 2 and consolidated cases were filed. On February 23, 2012, the Commission issued its Entry on Rehearing finding that the Stipulation, as a package, did not benefit ratepayers and was not in the public interest and, thus, did not satisfy the three-part test for the consideration of stipulations. AEP-Ohio was directed to provide notice to the Commission within 30 days whether it intended to modify or withdraw its ESP.

C. Pending Modified Electric Security Plan

On March 30, 2012, AEP-Ohio filed a modified ESP (modified ESP) for the Commission's consideration. As proposed, the modified ESP would commence June 1, 2012, and continue through May 31, 2015. As proposed in the application, the Company states for all customer classes, customers in the CSP rate zone will experience, on average, an increase of two percent annually and customers in the OP rate zone will experience, on average, an increase of four percent annually. The modified ESP proposes the recovery of other costs through riders during the term of the electric security plan. In addition, the

3 Including an emergency curtailment proceeding in Case Nos. 10-343-EL-ATA and 10-344-EL-ATA (Emergency Curtailment Cases); a request for the merger of CSP with OP in Case No. 10-2376-EL-UNC (Merger Case); the Commission review of the state compensation mechanism for the capacity charge to be assessed on competitive retail electric service (CRES) providers in Case No. 10-2929-EL-UNC (Capacity Case); and a request for approval of a mechanism to recover deferred fuel costs and accounting treatment in Case Nos. 11-4920-EL-RDR and 11-4921-EL-RDR (Phase-in Recovery Cases).

4 By entry issued on March 7, 2012, the Commission again approved and confirmed the merger of CSP into OP, effective December 31, 2011, in the Merger Case.

modified ESP contains provisions addressing distribution service, economic development, alternative energy resource requirements, and energy efficiency requirements.

The modified ESP also sets forth that AEP-Ohio will begin an energy auction for 100 percent of its SSO load beginning in 2015, with full delivery and pricing through a competitive auction process for AEP-Ohio's SSO customers beginning in June 2015. Beginning six months after the final order in the modified ESP case, the application states AEP-Ohio will begin conducting energy auctions for five percent of the SSO load. In addition, the modified ESP provides for the elimination of American Electric Power Corporation's East Interconnection Pool Agreement and describes the plan for corporate separation of AEP-Ohio's generation assets from its distribution and transmission assets.

In addition to the parties previously granted intervention in this matter, following AEP-Ohio's submission of its modified ESP, the following parties, were granted intervention on April 26, 2012: Interstate Gas Supply, Inc. (IGS); The Ohio Association of School Business Officials, The Ohio School Boards Association, The Buckeye Association of School Administrators, and The Ohio Schools Council (collectively, Ohio Schools); Ohio Farm Bureau Federation; Ohio Restaurant Association; Duke Energy Ohio, Inc. (Duke); Duke Energy Commercial Asset Management Inc. (DECAM); Direct Energy Services, LLC and Direct Energy Business, LLC (Direct); The Ohio Automobile Dealers Association (OADA); The Dayton Power and Light Company; The Ohio Chapter of the National Federation of Independent Business (NFIB); Ohio Construction Materials Coalition; Council of Smaller Enterprises; Border Energy Electric Services, Inc.; University of Toledo Innovation Enterprises Corporation; Summit Ethanol, LLC d/b/a POET Biorefining-Leipsic and Fostoria Ethanol, LLC d/b/a POET Biorefining-Fostoria (Summit Ethanol); city of Upper Arlington, Ohio; Ohio Business Council for a Clean Economy; IBEW Local Union 1466 (IBEW); city of Hillsboro, Ohio; and CPV Power Development, Inc.

D. Summary of the Hearings on Modified Plan

1. Local Public Hearings

Four local public hearings were held in order to allow AEP-Ohio's customers the opportunity to express their opinions regarding the issues raised within the modified application. Public hearings were held in Canton, Columbus, Chillicothe, and Lima. At the local hearings, a total of 67 witnesses[5] offered testimony: 17 witnesses in Canton, 31 witnesses in Columbus, 10 witnesses in Chillicothe, and nine witnesses in Lima. In addition to the public testimony, numerous letters were filed in the docket regarding the proposed ESP applications.

5 One witness, Doug Leuthold, testified at both the Columbus and Lima public hearings.

At each of the public hearings, numerous witnesses testified in support of AEP-Ohio's modified ESP. Specifically, many witnesses testified on behalf of community groups and non-profit organizations that praised AEP-Ohio's charitable support to their organizations. Witnesses that testified in favor of the modified ESP also noted that AEP-Ohio maintains a positive corporate presence and promotes economic development endeavors throughout its service territory. Members of local unions testified in support of AEP-Ohio's proposal, explaining it would not only allow AEP-Ohio to retain jobs, but also create new jobs as AEP-Ohio continues to expand its infrastructure throughout the region.

Several residential customers testified at the public hearings in opposition to AEP-Ohio's modified ESP, noting an increase in customer rates would be burdensome in light of the current economic recession. Many of these witnesses pointed out that low-income and fixed-income residential customers would be particularly vulnerable to any rate increases. Several witnesses also argued that the proposed application might limit customers' ability to shop for a CRES supplier.

In addition, many witnesses testified on behalf of small business and commercial customers. These witnesses argued the proposed rate increases would be burdensome on small businesses who cannot take on any electric rate increases without either laying off employees or passing costs on to customers. Representatives on behalf of school districts also testified that the modified ESP could create a financial strain on schools throughout AEP-Ohio's service territory.

2. Evidentiary Hearing

The evidentiary hearing commenced on May 17, 2012. Twelve witnesses testified on behalf of AEP-Ohio, 10 witnesses on behalf of the Staff, and 54 witnesses offered testimony on behalf of various interveners to the cases. In addition, AEP-Ohio offered three witnesses on rebuttal. The evidentiary hearing concluded on June 15, 2012. Initial briefs and reply briefs were due June 29, 2012, and July 9, 2012, respectively. For those parties that filed a brief or reply brief addressing select issues, oral arguments were held before the Commission on July 13, 2012.

E. Procedural Matters

1. Motions to Withdraw

On May 4, 2012, the city of Hilliard filed a notice requesting to withdraw as an intervenor from the modified ESP cases. Also on May 4, 2012, IBEW filed a notice stating that it intends to withdraw as an intervenor in these proceedings. The Commission finds IBEW's and Hilliard's requests to withdraw reasonable and should be granted.

2. Motions for a Protective Order

On May 2, 2012, AEP-Ohio filed a motion for a protective order, seeking protective treatment of supplemental testimony and corresponding exhibits of AEP-Ohio witness Nelson containing confidential and proprietary information relating to the Turning Point Solar project (Turning Point). On May 4, 2012, OMAEG filed a motion for a protective order relating to proprietary business information of OSCO Industries, Summitville Tiles, Belden Brick, Whirlpool Corporation, Lima Refining, and AMG Vanadium. Also, on May 4, 2012, IEU filed a motion for a protective order seeking to protect confidential and proprietary information contained within witness Kevin Murray's testimony. FES filed a motion for protective treatment on May 4, 2012, for confidential items contained in attachments to witness Jonathan Lesser's testimony. In addition, Exelon filed a motion for protective order seeking protection of confidential and proprietary information contained within witness Fein's direct testimony. On May 11, 2012, AEP-Ohio filed an additional motion for protective order to support the protection of confidential AEP-Ohio information contained within IEU witness Murray, FES witness Lesser, and Exelon witness Fein's testimony. Finally, on the record in these proceedings May 17, 2012, AEP-Ohio also sought the continuation of protective treatment of exhibits attached to AEP-Ohio witness Jay Godfrey, as previously set forth in AEP-Ohio's July 1, 2011, motion for a protective order (Tr. at 24).

At the evidentiary hearing on May 17, 2012, the attorney examiners granted the motions for protective order, finding the information specified within the parties' motions constitutes confidential, proprietary, and trade secret information, and meets the requirements contained within Rule 4901-1-24, Ohio Administrative Code (O.A.C.) (*Id.* at 23-24). Rule 4901:1-24(F), O.A.C., provides that, unless otherwise ordered, protective orders prohibiting public disclosure pursuant to Rule 4901:1-24(D), O.A.C., shall automatically expire after 18 months. Therefore, confidential treatment shall be afforded for a period ending 18 months from the date of this order, until February 8, 2014. Until that date, the Docketing Division should maintain, under seal, the conditional diagrams, filed under seal. Rule 4901:1-24(F), O.A.C., requires any party wishing to extend a protective order to file an appropriate motion at least 45 days in advance of the expiration date, including a detailed discussion of the need for continued protection from disclosure. If no such motion to extend confidential treatment is filed, the Commission may release this information without prior notice to the parties.

In addition, on June 29, 2012, IEU and Ormet filed motions for protective order regarding items contained within their initial briefs. Specifically, both the information for which IEU and Ormet's are seeking confidential treatment was already determined to be confidential in the evidentiary hearing and was discussed in a closed record. On July 5, 2012, AEP-Ohio filed a motion for protective order over the items contained within Ormet and IEU's briefs, noting that it contains proprietary and trade secret information. On July 9, Ormet filed an additional motion for protective order for the same information, which it also included in its reply brief filed on July 9, 2012. Similarly, AEP-Ohio filed a motion for protective order on July 12, 2012, in support of Ormet's motion, as it contains AEP-Ohio's confidential trade secret information. As the attorney examiners previously found the information contained within the IEU and Ormet's initial briefs and Ormet's reply brief was confidential in the evidentiary hearing, we affirm this decision and find that confidential treatment shall be afforded for a period ending 18 months from the date of this order, until February 8, 2014.

3. Requests for Review of Procedural Rulings

IEU argues that the record improperly includes evidence of stipulations as precedent. Specifically, IEU argues that several witnesses relied on Duke Energy-Ohio's ESP to indicate that certain proposed riders were appropriate. IEU also points out that a witness relied on AEP-Ohio's distribution rate case stipulation as evidence of AEP-Ohio's capital structure. IEU claims that these stipulations expressly state that no party or Commission order may cite to a stipulation as precedent, and accordingly, IEU requests that the references to stipulations be struck.

The Commission finds that IEU's request to strike portions of the record should be denied. We acknowledge that individual components agreed to by parties in one proceeding should not be binding on the parties in other proceedings, but we find that references to other stipulations in this proceeding were limited in scope and did not create any prejudicial impact on parties that signed the stipulations. Consistent with our Finding and Order in Case No. 11-5333-EL-UNC, we also note that, while parties may agree not to be bound by the provisions contained within a stipulation, these limitations do not extend to the Commission.

In addition, IEU claims the attorney examiners improperly denied IEU's motions to compel discovery. In its motions to compel discovery, IEU sought information related to AEP-Ohio's forecasts of the RPM price for capacity, which IEU alleges would have provided information relating to the transfer of AEP-Ohio's Amos and Mitchell generating units.

The Commission finds the attorney examiners' denials of IEU's motions to compel discovery were proper and should be upheld. As noted in AEP-Ohio's memorandum contra the motion to compel, the information IEU sought relates to AEP-Ohio forecasts beyond the period of this modified ESP. As these proceedings relate to the appropriateness of AEP-Ohio's modified ESP, we find that any forecasts beyond the terms contained within AEP-Ohio's application are irrelevant and unlikely to lead to discoverable information. Accordingly, the attorney examiners' ruling is affirmed.

On July 13, 2012, OCC filed a motion to strike four specific portions of AEP-Ohio's reply brief at pages 29-30, 33-34, 68-69, 97-99, including footnotes, and attachments A and

B, as OCC asserts the information is not based on the record in the modified ESP proceeding but reflects the Commission's Order issued in the Capacity Case on July 2, 2012. OCC submits that the Commission has previously recognized that "it is improper to rely on claims in the brief that are unsupported by evidence within the record." In this instance, OCC points out that AEP-Ohio attached to its reply brief, documents that were not part of the record evidence or designated late-filed exhibits, a statement by Standard and Poor's (Attachment A) and the Company's recalculation of its ESP/MRO test (Attachment B) based on the Commission's decision in the Capacity Case. Since neither document is part of the modified ESP record evidence, OCC reasons that the attachments are hearsay which are not excused by any exception to the hearsay rule. OCC also notes that the reply brief includes discussion of recent storms in the Midwest and the East Coast, and there is nothing in the record regarding the strength of the winds or the ability of the Company's system to withstand hurricane force winds. Furthermore, neither the attachments nor AEP-Ohio's assertions was subjected to cross-examination by the parties nor the parties afforded an opportunity to rebut the associated arguments of the Company. For these reasons, OCC requests that Attachments A and B and the specified portions of the reply brief be stricken.

In its memorandum contra, AEP-Ohio asserts that discussion of matters related to the Commission's Capacity Case decision were appropriate. AEP-Ohio notes that it is fair to rely on a Commission opinion and order and reasonable to consider the impact of the Capacity Case on these proceedings, as evidenced by Commission questions during the oral arguments held on July 13, 2012. In addition, AEP-Ohio points out that several parties' reply briefs also included significant discussion of the impact of the Capacity Case on the modified ESP. Similarly, AEP-Ohio notes that the attachments indicate the financial impact of the Capacity Case on AEP-Ohio, and that the items are consistent with the testimony of AEP-Ohio witness Hawkins. Finally, AEP-Ohio provides that its references to major storms that occurred this summer relate to customer expectations and AEP-Ohio's need for the DIR.

The Commission finds that OCC's motion to strike portions of AEP-Ohio's reply brief should be denied. The Company's reply brief reports the impact of the Commission's Order in the Capacity Case based on subject matters and information subjected to extensive cross-examination by the parties in the course of this proceeding. Furthermore, several of the parties to this proceeding discuss in their respective reply briefs the Order in the Capacity Case. For these reasons, we conclude that it would be improper to strike the portions of AEP-Ohio's reply brief, including Attachment B, which reflect AEP-Ohio's interpretation of the Commission Capacity Order as requested by OCC. We, likewise, deny OCC's request to strike the Company's reference to recent storms, where the Company offered support for its position on customer reliability expectations. Customer service reliability was an issue raised and discussed by AEP-Ohio as well as OCC. However, Attachment A to the Company's reply brief is a July 2, 2012 statement by

Standard & Poor's regarding the effect of the Commission's Capacity Charge Order, and should be stricken. We find that the Company's Attachment A is not part of the record and should not be considered by the Commission in this proceeding.

On July 20, 2012, OCC/APJN filed a motion to take administrative notice of several items contained within the record of the Capacity Case. Specifically, OCC/APJN seek administrative notice of pages 3, 9, and 12 of the direct testimony of AEP-Ohio witness Munczinski, pages 19-20 of the rebuttal testimony of AEP-Ohio witness Allen, pages 304, 348-350, and 815 of the hearing transcripts, and AEP-Ohio's post-hearing initial and reply briefs. OCC/APJN opine that the record should be expanded to include these materials in order to have a more thorough record on issues pertaining to customer rates. Further, OCC/APJN state that no parties would be prejudiced as parties, particularly those involved in the Capacity Case, who had opportunities to explain and rebut these items.

AEP-Ohio filed a memorandum contra OCC/APJN's motion on July 24, 2012. AEP-Ohio argues that OCC/APJN improperly seeks to add documents into the record at this late stage, is not only inappropriate, but also unnecessary as there are no further actions to these proceedings except the Commission opinion and order and rehearing. AEP-Ohio notes the Commission has broad discretion in handling its proceedings, but points out that the small subset of information could have a prejudicial effect to parties, and due process would require that other parties be permitted to add other items to the record. In addition, AEP-Ohio explains that OCC/APJN had the opportunity in the ESP proceedings to further explore areas of the Capacity Case that were related to parts of the modified ESP.

On August 6, 2012, FES also filed a memorandum contra OCC/APJN's motion. On August 7, 2012, OCC/APJN filed a motion to strike FES's memorandum contra. In support of its motion to strike, OCC/APJN argues that FES filed its memorandum contra 17 days after OCC/APJN filed its motion, past the procedural deadlines established by attorney examiner entry issued April 2, 2012. The Commission finds that OCC/APJN's motion to strike FES's memorandum contra OCC/APJN's motion should be granted. By entry issued April 2, 2012, the attorney examiner set an expedited procedural schedule establishing that any memoranda contra be filed within five calendar days after the service of any motions. Therefore, as FES filed its memorandum contra 17 days after OCC/APJN filed its motion, OCC/APJN's motion to strike shall be granted.

The Commission finds that OCC's motion to take administrative notice should be denied. AEP-Ohio correctly points out that the timing of OCC/APJN's request is troublesome and problematic. While the Commission has broad discretion to take administrative notice, it must be done in a manner that does not harm or prejudice any other parties that are participating in these proceedings. Were the Commission to take notice of this narrow window of information, we would be allowing a party to supplement the record in a misleading manner. Further, while we acknowledge that parties may rely on the Commission's order in the Capacity Case, as it speaks for itself, to show effects on items in this proceeding, to exclusively select narrow and focused items in an attempt to supplement the record is not appropriate. Accordingly, we deny OCC's motion.

II. DISCUSSION

A. Applicable Law

Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing AEP-Ohio's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, amended by Senate Bill 221 (SB 221).

Section 4928.02, Revised Code, states that it is the policy of the state, *inter alia*, to:

(1) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service.

(2) Ensure the availability of unbundled and comparable retail electric service.

(3) Ensure diversity of electric supplies and suppliers.

(4) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management (DSM), time-differentiated pricing, and implementation of advanced metering infrastructure (AMI).

(5) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality.

(6) Ensure effective retail competition by avoiding anticompetitive subsidies.

(7) Ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power.

(8) Provide a means of giving incentives to technologies that can adapt to potential environmental mandates.

(9) Encourage implementation of distributed generation across customer classes by reviewing and updating rules governing issues such as interconnection, standby charges, and net metering.

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

In addition, SB 221 enacted Section 4928.141, Revised Code, which provides that effective January 1, 2009, electric utilities must provide consumers with an SSO consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the electric utility's default SSO.

AEP-Ohio's modified application in this proceeding proposes an ESP pursuant to Section 4928.141, Revised Code. Paragraph (B) of Section 4928.141, Revised Code, requires the Commission to hold a hearing on an application filed under Section 4928.143, Revised Code, to send notice of the hearing to the electric utility, and to publish notice in a newspaper of general circulation in each county in the electric utility's certified territory.

Section 4928.143, Revised Code sets out the requirements for an ESP. Under paragraph (B) of Section 4928.143, Revised Code an ESP must include provisions relating to the supply and pricing of generation service. The ESP, according to paragraph (B)(2) of Section 4928.143, Revised Code, may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress (CWIP), an unavoidable surcharge for the cost of certain new generation facilities, conditions or charges relating to customer shopping, automatic increases or decreases, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development.

The statute provides that the Commission is required to approve, or modify and approve the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply in an MRO under Section 4928.142, Revised Code. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

B. Analysis of the Application

1. Base Generation Rates

As part of its modified ESP application, AEP-Ohio proposes to freeze base generation rates until all rates are established through a competitive bidding process. AEP-Ohio maintains that the fixed pricing is a benefit to customers by providing reasonably priced electricity in furtherance of Section 4928.02(A), Revised Code. AEP-Ohio explains that while the base generation rates will remain frozen, it will relocate the current Environmental Investment Carrying Cost Rider (EICCR) into the base generation rates, which will result in the elimination of the EICCR. AEP-Ohio witness Roush provides the change is merely a roll in and will be "bill neutral" for all AEP-Ohio customers (AEP-Ohio Ex. 118 at 8; AEP-Ohio Ex. 111 at 10-11).

While AEP-Ohio's base generation rates will be frozen under the modified ESP, AEP-Ohio witness Roush notes that the generation rates are based on cost relationships, and include cross-subsidies among tariff classes, which, upon class rates being based on an auction, may result in certain customer classes being disproportionately impacted by rate changes. Mr. Roush notes that residential customers with high winter usage may face unexpected impacts, but that a possible solution may be to phase-out lower rates for high winter usage customers (*Id.* at 14-15).

OADA supports the adoption of the base generation rate design as proposed, advocating that the consistency in the rate design is beneficial for GS-2 customers (OADA Br. at 2). OCC and APJN claim that frozen base generation rates is not a benefit to customers, as the price of electricity offered by CRES providers have declined and may continue to decline through the term of the ESP (OCC Ex. 111 at 15). OCC and APJN also point out that the inclusion of numerous riders, including the retail stability rider (RSR) and the deferral created in the Capacity Case will result in increases in the rates residential customers continue to pay. (OCC/APJN Br. at 43-44.)

The Commission finds that AEP-Ohio's proposed base generation rates are reasonable. We note that AEP-Ohio's base generation rate design was generally unopposed, as most parties supported AEP-Ohio's proposal to keep base generation rates frozen. Although OCC and APJN conclude that the base generation rate plan does not benefit customers, OCC and APJN failed to justify their assertion and offer no evidence within the record other than the fact that the modified ESP contains several riders. Accordingly, the modified ESP's base generation rates should be approved. In addition, as AEP-Ohio raised the possibility of disproportionate rate impacts on customers when class rates are set by auction, we direct the attorney examiners to establish a new docket within

90 days from the date of this opinion and order and issue an entry establishing a procedural schedule to allow Staff and any interested party to consider means to mitigate any potential adverse rate impacts for customers upon rates being set by auction. Further, the Commission reserves the right to implement a new base generation rate design on a revenue neutral basis for all customer classes at any time during the term of the modified ESP.

2. Fuel Adjustment Clause and Alternative Energy Rider

(a) Fuel Adjustment Clause

The Commission approved the current fuel adjustment clause (FAC) mechanism in the Company's ESP 1 case pursuant to Section 4928.143(B)(2)(a), Revised Code.[6] In this modified ESP application, AEP-Ohio requests continuation of the current FAC mechanism, with modifications. The Company proposes to modify the FAC by separating out the renewable energy credit (REC) expense component of the fuel clause and recovering the REC expense through the newly proposed alternative energy rider (AER) mechanism. The Company also requests approval to unify the CSP and OP FAC rates into a single FAC rate effective June 2013. AEP-Ohio reasons that delaying unification of the FAC rates until June 2013, to coincide with the implementation of the Phase-In Recovery Rider (PIRR), limits the impact on both CSP and OP rate zones which results in a net decrease in rates of $0.69 per megawatt hour (MWh) for a typical CSP transmission voltage customer and a net increase in rates of $0.02 per MWh for a typical OP transmission voltage customer. (AEP-Ohio Ex. 111 at 5-6; AEP-Ohio Ex. 103 at 14-20.)

Beginning January 1, 2014, after corporate separation is effective, AEP-Ohio's generation affiliate, AEP Generation Resources Inc. (GenResources), will bill AEP-Ohio its actual fuel costs in the same manner and detail as currently performed by AEP-Ohio, and the costs will continue to be recovered through the FAC. As a component of the modified ESP, AEP-Ohio proposes that as of January 1, 2015, all energy and capacity to serve the Company's SSO load be supplied by auction, whereupon the FAC mechanism will no longer be necessary. (AEP-Ohio Ex. 103 at 14-20.)

In opposition to the FAC, Ormet argues that the FAC has caused significant increases in the cost of electric service, rising 22 percent for GS-4 customers since 2011. Ormet asks that the Commission temper the impact of FAC increases and improve the transparency of the cause for increasing FAC costs, as well as reconsider the FAC rate design, to avoid cost shifts between low load factor customers and high load factor customers. Ormet, a 98.5 percent load factor customer, asserts that it pays an equal share of the FAC costs as a customer that uses all its energy on-peak. As such, Ormet contends that the FAC rate design violates the principle of cost causation. Ormet suggests that this

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6 In re *AEP-Ohio*, ESP 1 Order at 13-15 (March 18, 2009).

modified ESP presents the Commission with the opportunity, as it is within the Commission's jurisdiction, to redesign the FAC, such that FAC costs are separated into charges which reflect on-peak and off-peak usage. (Ormet Ex. 106B at 19; Ormet Br. at 13-15; Ormet Reply Br. at 14-16.)

The Company responds that Ormet's arguments on the FAC reflect improper calculations and is based on forecasted FAC rates. More importantly, AEP-Ohio points out that the FAC is ultimately based on actual FAC costs and any increases in the FAC rate cannot appropriately be attributed to the modified ESP. Ormet is served by AEP-Ohio pursuant to a unique arrangement and as such avoids charges that other similarly situated customers pay; however, the Company requests that Ormet not be permitted to avoid fuel costs. (AEP-Ohio Reply Br. at 5-6.)

The Commission notes that currently, through the FAC mechanism, AEP-Ohio recovers prudently incurred fuel and associated costs, including consumables related to environmental compliance, purchase power costs, emission allowances, and costs associated with carbon-based taxes. We note that, since January 1, 2012, AEP-Ohio has been collecting its full fuel expense and no further fuel expenses are being deferred.

We interpret Ormet's arguments to more accurately request the institution of a fuel rate cap on the FAC or to revise the FAC rate design. The Commission rejects Ormet's request to review and redesign the FAC. The FAC rate mechanism is reconciled to actual FAC costs each quarter and annually audited for accounting accuracy and prudency. Furthermore, as AEP-Ohio notes, Ormet's rates are set pursuant to its unique arrangement as opposed to the Company's SSO rates paid by other high load industrial and commercial customers. By way of Ormet's unique arrangement, Ormet is provided some rate stability and rate certainty and we see no need to redesign the FAC for Ormet's benefit. No other intervener took issue with the continuation and the proposed modification of the FAC. The Commission finds that the FAC rates should continue on a separate rate zone basis. We note that there are a few Commission proceedings pending that will affect the FAC rate for each rate zone which the Commission believes will be better reviewed and adjusted if the FAC mechanisms remain distinguishable. Further, as discussed, below, maintaining FAC rates on a separate basis is necessary to be consistent with our decision regarding recovery of the PIRR.

(b) <u>Alternative Energy Rider</u>

As noted above, AEP-Ohio proposes to begin recovery of REC expenses, associated with renewable energy purchase agreements (REPAs) or REC purchases by means of the new AER mechanism to be effective with this modified ESP. With the proposed modification, the Company will continue to recover the energy and capacity components of renewable energy cost through the FAC, until the FAC expires. After the FAC ends, energy and capacity associated with REPAs will be sold into the PJM Interconnection, LLC

(PJM) market and offset the total cost of the REPAs, with the balance of REC expense to be recovered from SSO customers through the AER. AEP-Ohio proposes that the AER be bypassable for shopping customers. The Company also proposes that where the REC is part of the REPA, the value of each component be based on the residual method using the monthly average PJM market price to value the energy component, the capacity will be valued using the price at which it can be sold into the PJM market and the remaining value would constitute the cost of the REC. The AER mechanism, according to AEP-Ohio, is consistent with Section 4928.143(B)(2)(a), Revised Code, and is essentially a partial unbundling of the FAC to provide greater price visibility of prudently-incurred REC compliance costs under Section 4928.66, Revised Code. The Company will make quarterly filings, in conjunction with the FAC, to facilitate the audit of the AER. AEP-Ohio reasons that the establishment of the AER for recovery of costs is uncontested, reasonable, and should be approved. The Company argues continuation and unification of the FAC and development and implementation of the AER, is reasonable and should be approved. (AEP-Ohio Ex. 103 at 18-19.)

Staff endorses the Company's requests to continue and consolidate the FAC rates for CSP and OP rate zones and to reclassify the RECs and REPA components for recovery through the AER, as proposed by the Company. However, Staff recommends that annual AER audit procedures be established and that the AER audit be conducted by the same auditor and in conjunction with the FAC audit to determine the appropriateness and recoverability of costs as a part of and between the AER and FAC mechanisms. As to the allocation of cost components, Staff agrees with the Company's proposal to allocate cost components of bundled products but suggests that the auditor detail how to best determine the cost components and how to apply the allocation to specific situations in the context of the FAC/AER audits. Staff recommends, and the Company agrees, that the auditor's allocation process be applied to AEP-Ohio's renewable generation from existing generation facilities. (Staff Ex. 104 at 2-3.)

No party took exception to the implementation of the AER mechanism. As proposed by AEP-Ohio, continuation of the FAC and establishment of the AER, through this modified ESP, is consistent with Section 4928.143(B)(2)(a), Revised Code, for the recovery of prudently incurred fuel costs and fuel-related costs and alternative energy and associated costs. We find the Company's proposal to continue the FAC and create the AER to better distinguish fuel and alternative energy costs to be reasonable and appropriate during the term of the modified ESP. We approve the continuation of the FAC and implementation of the AER mechanisms, consistent with the audit recommendations made by Staff. The next audit of AEP-Ohio's FAC shall also include an audit of the AER mechanisms and the allocation method for classification of the REPA components and their respective values. In all other respects, the Commission approves the continuation of the FAC rate mechanisms and the creation of the AER rate mechanism for each rate zone.

3. Timber Road

AEP-Ohio states that it conducted a request for proposal (RFP) process to competitively bid and secure additional renewable resources. As a result of AEP- Ohio's need for in-state renewables, AEP-Ohio only considered bids for projects in Ohio, and ultimately selected the proposal from Paulding for its Timber Road wind farm. Specifically, the Timber Road REPA will provide AEP-Ohio a 99 MW portion of Timber Road's electrical output, capacity and environmental attributes for 20 years as necessary for the Company to meet its increasing renewable energy benchmarks as required by Section 4928.64(C)(3), Revised Code. (AEP-Ohio Ex. 109 at 10-15; Paulding Ex. 101 at 1-4.)

AEP-Ohio testified that the 20-year agreement facilitates long-term financing by the developer, reduces up front costs, and allows for price certainty for AEP-Ohio customers. Paulding offers that although the project is capital intensive the fact that there are no fuel costs equates to no significant cost variables creating long-term risk for customers. AEP-Ohio argues that the Timber Road REPA provides the Company and its customers, with access to affordable renewable energy from an in-state resource supporting the state policy to facilitate the state's effectiveness in the global economy, Section 4928.02(N), Revised Code. (AEP-Ohio Ex. 109 at 16-18; Paulding Ex. 101 at 4-5.)

Staff supports AEP-Ohio's REPA with Paulding and the Timber Road contract as reasonable and prudent. Accordingly, Staff advocates its approval and that AEP-Ohio be permitted to recover costs associated with energy, capacity, and RECs outlined in the contract, subject to annual FAC and AER audits. The Company agrees with Staff that the implementation of the Timber Road REPA should be subject to the FAC and AER audit, as offered in the testimony of AEP-Ohio witness Nelson. AEP-Ohio commits to acquiring RECs to meet its portfolio requirements on behalf of its SSO load and to recover the costs through the AER once the FAC is terminated. (Staff Ex. 103 at 2-3; Tr. at 2498-2499; AEP-Ohio Ex. 103 at 18.)

The Commission finds that the long-term Timber Road REPA promotes diversity of supply, consistent with state policies set forth in Section 4928.02, Revised Code. Further, based on the evidence of record, the Timber Road project benefits Ohio consumers and supports the Ohio economy. Accordingly, the Commission finds it reasonable and appropriate to allow the Company to recover the cost of the Timber Road REPA through the bypassable FAC/AER mechanisms.

4. Generation Resource Rider

AEP-Ohio requests establishment of a non-bypassable, Generation Resource Rider (GRR) pursuant to Section 4928.143(B)(2), Revised Code, to recover the cost of new generation resources including, but not limited to, renewable capacity that the Company owns or operates for the benefit of Ohio customers. At this time, the Company proposes the rider as a placeholder and expects that the only project to be included in the GRR will be the Turning Point facility, assuming need is established in Case Nos. 10-501-EL-FOR and 10-502-EL-FOR.[7] To be clear, although the Company provided an estimate of the revenue requirement for the Turning Point project, as requested by the Commission, AEP-Ohio is not seeking recovery of any costs for the Turning Point facility in this ESP. The Company asks that the GRR be established at zero with the amount of the rider to be determined, and the remaining statutory requirements to be met, as part of a subsequent Commission proceeding. (AEP-Ohio Ex. 103 at 20-21; AEP-Ohio Ex. 104; Tr. at 2514, 599, 1170, 2139- 2140.)

UTIE encourages the Commission's approval of the GRR as a regulatory mechanism pursuant to the authority granted under Section 4928.143(B)(2)(c), Revised Code, to adopt a non-bypassable surcharge for new electric generation (UTIE Br. at 1-2). NRDC and OEC support the proposed GRR, including the Timber Road REPA and the Turning Point project, with certain modifications, as permitted under Section 4928.143(B)(2)(c), Revised Code. NRDC and OEC recommend that the GRR be limited to only renewable and alternative energy projects or qualified energy efficiency projects, and also recommend that the Company develop a crediting system to ensure that shopping customers do not pay twice for renewable energy. NRDC and OEC reason that AEP-Ohio could make the RECs available to CRES providers based on the CRES provider's share of the load served or by liquidating the RECs in the market and crediting the revenue to the GRR. (NRDC Ex. 101 at 11; NRDC/OEC Reply Br. at 1.)

However, while Staff does not foresee any need for additional generation by AEP-Ohio, Staff and UTIE acknowledge and endorse the adoption of the GRR mechanism to facilitate the Commission's allowance for the construction of new generation facilities (Staff Ex. 110 at 7; Tr. at 4599; UTIE Reply Br. 1-2).

On the other hand, numerous interveners oppose the adoption of the GRR. IGS requests that the Commission reject the GRR or if it is not rejected, that the GRR be made bypassable or modified so the benefits flow to shopping customers (IGS Ex. 101 at 27-28). Wal-Mart requests that the GRR not be imposed on shopping customers because approval of a non-bypassable GRR would violate cost causation principles, send an incorrect price signal, and cause shopping customers to pay twice but receive no benefit (Wal-Mart Ex. 101 at 5-6).

7 A stipulation between the Company and the Staff was filed agreeing, among other things, that as a result of the requirements of Sections 4928.143(B)(2)(c) and 4928.64(B)(2), Revised Code, which require AEP-Ohio to obtain alternative energy resources including solar resources in Ohio, the Commission should find that there is a need for the 49.9 MW Turning Point Solar project. The Commission decision in the case is pending.

RESA and Direct contend that the GRR will inhibit the growth of the competitive retail electric market and violates the state policy set forth in Section 4928.02(H), Revised Code, which prohibits the collection of generation-based rates through a non-bypassable rider. Similarly, IGS reasons that the GRR is intended to recover the cost for new generation to serve SSO customers and, therefore, the GRR amounts to an anticompetitive subsidy on CRES providers for the benefit of noncompetitive retail electric service, or, according to Wal-Mart, requires shopping customers to pay twice. IGS recommends that AEP-Ohio develop renewable energy projects on its own with recovery through market prices. RESA and Direct reason that AEP-Ohio's request is premature and creates uncertainty for CRES providers who are also required to comply with Ohio's renewable energy portfolio standards. RESA and Direct contend that, to the extent the Commission adopts the GRR, the GRR should not be assessed to shopping customers. RESA and Direct propose that the GRR be set at zero and incorporation of the Turning Point project or other facilities should occur in a separate case. (RESA Ex. 102 at 12; RESA/Direct Br. 18-21; IGS Br. at 13; Wal-Mart Ex. 101 at 5.)

To make the GRR benefit shopping and non-shopping customers, IGS suggests that AEP-Ohio sell the generated electricity on the market with revenues to be credited against the GRR or the renewable energy credits used to meet the requirements for all customers. IGS notes that AEP-Ohio witnesses agree that crediting the revenues against the GRR is reasonable. (IGS Ex. 101 at 27-28; Tr. 599, 1169-1170.)

OCC, APJN, IEU and FES contend that AEP-Ohio has inappropriately conflated two unrelated statutes, Sections 4928.143(B)(2)(c) and 4928.64, Revised Code, in support of the GRR. The goals of the two sections are different according to the interpretation of the aforementioned interveners. They contend that the purpose of Section 4928.64, Revised Code, is to require electric distribution utilities and CRES providers to comply with renewable energy benchmarks and paragraph (E) of Section 4928.64, Revised Code, directs that costs incurred to comply with the renewable energy benchmarks shall be bypassable. Whereas, according to IEU and FES, Section 4928.143(B)(2)(c), Revised Code, permits the Commission to implement a market safety valve under specific requirements should Ohio require additional generation. FES notes that AEP-Ohio has sufficient energy and capacity for the foreseeable future. IEU and FES interpret the two statutory provisions to affirmatively deny non-bypassable cost recovery under Section 4928.143(B)(2)(c), Revised Code, for renewable energy projects. IEU and FES contend that their interpretation is confirmed by the language in Section 4928.143(B), Revised Code, which states "Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except...division (E) of section 4928.64... ." Thus, FES reasons the Commission is expressly prohibited from authorizing a provision of an ESP which conflicts with Section 4928.64(E), Revised Code. (FES Br. at 87-90; IEU Br. 74-76; Tr. at 226-227.)

Further, IEU, FES, OCC, IGS and APJN argue that the statute requires, and AEP-Ohio has failed to demonstrate, the need for and the terms and conditions of recovery for the Turning Point project in this proceeding pursuant to Section 4928.143(B)(2)(c), Revised Code. Finally, IEU submits that AEP-Ohio has failed to offer any evidence as to the effect of the GRR on governmental aggregation, as required in accordance with the Commission's obligation under Section 4928.20(K), Revised Code. For these reasons, IEU, IGS, FES, OCC and APJN request that the Company's request to implement the GRR be denied. (Tr. 1170, 570-574, 2644-2646; FES Br. at 87-94; FES Reply Br. at 22-24, IGS Reply Br. at 5-6; OCC/APJN Br. at 84-85; IEU Br. 74-76.)

Staff notes that there are a number of statutory requirements pursuant to Section 4928.143(B)(2)(c), Revised Code, that OP has not satisfied as a part of this modified ESP proceeding but will be addressed in a future proceeding, including the cost of the proposed facility, alternatives for satisfying the in-state solar requirements, a demonstration that Turning Point was or will be sourced by a competitive bid process, the facility is newly used and useful on or after January 1, 2009, the facility's output is dedicated to Ohio consumers and the cost of the facility, among other issues. Staff notes the need for the Turning Point facility has been raised by parties in another case and a decision by the Commission is pending.[8] Staff emphasizes that the statutory requirements would need to be addressed, and a decision made by the Commission, before recovery could commence via the GRR mechanism. Further, Staff suggests that it is in this future proceeding that parties should explore whether the GRR should be applied to shopping customers. (Staff Ex. 106 at 11-14.)

FES responds that the language of Section 4928.143(B)(2)(c), Revised Code, omits any asserted discretion of the Commission to consider the requirements to comply with the statute outside of the ESP case, as AEP-Ohio and Staff offer. Nor is it sufficient policy support, according to FES and IGS, that customers may transition from shopping to non-shopping and back during the useful life of the Turning Point facility as claimed by AEP-Ohio. The interveners argue AEP-Ohio overlooks that, as proposed by the Company, the load of all its non-shopping customers will be up for bid as of June 1, 2015. With that in mind, FES ponders why customers of AEP-Ohio competitors should pay for AEP-Ohio facilities after May 31, 2015. (FES Reply Br. at 24-25; IGS Reply Br. at 4.)

UTIE notes that parties that oppose the approval of the GRR, on the premise that it will require shopping customers to pay twice, overlook AEP-Ohio's proposal to allocate RECs between shopping and non-shopping customers, to sell the energy and capacity from the Turning Point facility into the market and credit such transactions against the GRR (UTIE Reply Br. at 2).

NRDC and OEC respond that it is disingenuous for parties to argue that establishing a placeholder rider as a part of an ESP is unlawful. The Commission has adopted placeholder riders in several previous Commission cases for AEP-Ohio, Duke

8 Case Nos. 10-501-EL-FOR and 10-502-EL-FOR.

Energy Ohio and the FirstEnergy operating companies.[9] Further, NRDC and OEC note that no party has waived its right to participate in subsequent GRR-related proceedings before the Commission. (NRDC/OEC Reply Br. at 2.)

The Company notes that four interveners support the adoption of the GRR and of the four supporters, two request modifications which are components already proposed by the Company.

First, AEP-Ohio addresses the arguments of FES and IEU that Section 4928.64(E), Revised Code, prohibits the use of Section 4928.143(B)(2)(c), Revised Code, for renewable generation projects. AEP-Ohio states that it recognizes the overlapping policies of the two statutes and offers that each section relates to the cost recovery aspect of the project, which as the Company interprets the statutes, will be addressed when cost recovery is requested in a future proceeding. Further, AEP-Ohio reasons that IEU's and FES's arguments are inappropriate as they would lead to the disallowance of a statutorily prescribed option merely because another option exists. In addition, AEP-Ohio contends, proper statutory construction seeks to give all statutes meaning and, therefore, both options are available to the Commission at its discretion.

It is premature, AEP-Ohio retorts, to assert as certain interveners have done, that the statutory requirements of Section 4928.143(B)(2)(c), Revised Code, have not been met by the Company. The statutory requirements of Section 4928.143(B)(2)(c), Revised Code, will be addressed in a separate proceeding before any costs can be recovered via the proposed GRR. AEP-Ohio asserts that the Commission is vested with the discretion to establish the GRR, as a zero-cost placeholder, as it has done in other Commission proceedings. The Company also proposes, and Staff agrees, that as a part of this future proceeding, the amount and prudency of costs associated with the Turning Point project and whether the GRR results in shopping customers paying twice for renewable energy compliance costs, among other issues will be determined. AEP-Ohio reiterates its plan to share the RECs from the Turning Point project between shopping and SSO customers on an annual basis. IGS, NRDC and Staff endorse AEP-Ohio's proposal to share the value of the Turning Point project between shopping and non-shopping customers. (AEP-Ohio Reply Br. at 7-10; Tr. at 2139-2140; NRDC/OEC Reply Br. at 1; Staff Ex. 110 at 7; Staff Br. at 20.)

The Commission interprets Section 4928.143(B)(2)(c), Revised Code, to permit a reasonable allowance for construction of an electric generating facility and the establishment of a non-bypassable surcharge, for the life of the facility where the electric utility owns or operates the generation facility and sourced the facility through a competitive bid process. Before authorizing recovery of a surcharge for an electric generation facility, the Commission must determine there is a need for the facility and to

9 In re AEP-Ohio, ESP 1 (March 18, 2009); *In re Duke Energy-Ohio*, Case No. 08-920-EL-SSO (December 17, 2008); *In re FirstEnergy*, Case No. 08-935-EL-SSO (March 25, 2009).

continue recovery of the surcharge, establish that the facility is for the benefit of and dedicated to Ohio consumers. AEP-Ohio will be required to address each of the statutory requirements, in a future proceeding, and to provide additional information including the costs of the proposed facility, to justify recovery under the GRR. However, the Commission notes that there shall be no allowances for recovery approved unless the need and competitive requirements of this section are met.

Furthermore, we disagree with the arguments that the language in Section 4928.143(B)(2)(c), Revised Code, requires the Commission to first determine, within the ESP proceeding, that there was a need for the facility. The Commission is vested with the broad discretion to manage its dockets to avoid undue delay and the duplication of effort, including the discretion to decide, how, in light of its internal organization and docket considerations, it may best proceed to manage and expedite the orderly flow of its business, avoid undue delay and eliminate unnecessary duplication of effort. *Duff v. Pub. Util. Comm.* (1978), 56 Ohio St. 2d 367, 379; *Toledo Coalition for Safe Energy v. Pub. Util. Comm.* (1982), 69 Ohio St. 2d 559, 560. Accordingly, it is acceptable for the Commission to determine the need for the Turning Point facility as a part of the Company's long-term forecast case filed consistent with Section 4935.04, Revised Code, wherein the Commission evaluates energy plans and needs. To avoid the unnecessary duplication of processes, the Commission has undertaken the determination of need for the Turning Point project in the Company's long-term forecast proceeding. The Commission interprets the statute not to restrict our determination of the need and cost for the facility to the time an ESP is approved but rather to ensure the Commission holds a proceeding before it authorizes any allowance under the statute. FES raises the issue of whether shopping customers should incur charges associated with AEP-Ohio's construction of generation facilities. The Commission finds that Section 4928.143(B)(2)(c), Revised Code, specifically provides that the surcharge be non-bypassable. However, the statute also provides that the electric utility must dedicate the energy and capacity to Ohio consumers. AEP-Ohio has represented that any renewable energy credits will be shared with CRES providers proportionate with such providers' share of the load. Accordingly, as long as AEP-Ohio takes steps to share the benefits of the project's energy and capacity, as well as the renewable energy credits, with all customers, we find that the GRR should be non-bypassable. Further, in the subsequent application for any cost recovery AEP-Ohio will have the burden to demonstrate compliance with the statutory requirements set forth in Section 4928.143(B)(2)(c), Revised Code.

Accordingly, the Commission approves the Company's request to adopt as a component of this modified ESP the GRR mechanism, at a rate of zero. It is not unprecedented for the Commission to adopt a mechanism, with a rate of zero, as a part of an ESP.[10] The Commission explicitly notes that in permitting the creation of the GRR, it is not authorizing the recovery of any costs, at this time.

5. Interruptible Service Rates

In its modified ESP, AEP-Ohio suggests it would be appropriate to restructure its current interruptible service provisions to make its offerings consistent with the options that will be available upon AEP-Ohio's participation in the PJM base residual auction beginning in June 2015. AEP-Ohio witness Roush provides that interruptible service is more frequently represented as an offset to standard service offer rates as opposed to a separate and distinct rate (AEP-Ohio Ex. 111 at 8). To make AEP-Ohio's interruptible service options consistent with the current regulatory environment, AEP-Ohio proposes that Schedule Interruptible Power-Discretionary (IRP-D) become available to all current customers and any potential customers seeking interruptible service (*Id.*). The IRP-D credit would increase to $8.21 per kw-month upon approval of the modified ESP (AEP-Ohio Ex. 100 at 9). AEP-Ohio proposes to collect any costs associated with the IRP-D through the RSR to reflect reductions in AEP-Ohio's base generation revenues (*Id.*).

OCC believes the IRP-D proposal violates cost causation principles, as the beneficiaries are customers with more than 1 MW of interruptible capacity, and does not apply to residential customers. OCC witness Ibrahim argues it is unfair for non-participating customers to make AEP-Ohio whole for any lost revenues associated with the IRP-D (OCC Ex. 110 at 11-12). Therefore, OCC recommends the IRP-D should not allow for any lost revenue associated with IRP-D credits to be collected through the RSR (*Id.*).

Staff suggests modifying the IRP-D credit based upon the state compensation mechanism approved in the Capacity Case (Staff Ex. 105 at 6-9). Staff witness Scheck recommended lowering the IRP-D credit to $3.34/kw-month (*Id.*). Further, Staff notes its preference of any interruptible service to be offered in conjunction with Commission approved reasonable arrangements, as opposed to tariff service (*Id*). EnerNOC states that a reasonable arrangement process is more transparent than an interruptible service credit, and notes that a subsidized IRP-D rate may impede AEP-Ohio's transition to a competitive market by reducing the amount of demand response resources that may participate in RPM auctions (EnerNOC Br. at 6-9).

OMAEG and OEG support the proposed IRP-D credit, but recommend it not be tied to approval of the RSR (OMAEG Br. at 21, OEG Br. at 15). Ormet also supports the IRP-D credit, noting that customers should be compensated for taking on an interruptible load (Ormet Br. at 21-22). OEG explains it is reasonable and consistent with state policy

10 *In re AEP-Ohio*, ESP 1 (March 18, 2009); *In re Duke Energy-Ohio*, Case No. 08-920-EL-SSO (December 17, 2008); *In re FirstEnergy*, Case No. 08-935-EL-SSO (March 25, 2009).

objectives under Section 4928.02, Revised Code, as it will promote economic development and innovation and market access for AEP-Ohio's customers. OEG witness Stephen Baron provides that the credit is beneficial to customers that participate in the IRP-D program who received a discounted price for power in exchange for interruptible service, which retains existing AEP-Ohio customers and can attract new customers to benefit the state's economic development (Tr. IV at 1125-1126, OEG Ex. 102 at 6-8). Mr. Baron notes that the IRP-D is beneficial to AEP-Ohio as well by allowing AEP-Ohio to have increased flexibility in providing its service, thus increasing overall system reliability (OEG Ex. 102 at 6-8). However, Mr. Baron believes that costs associated with the IRP-D would be more appropriate to recover under the EE/PDR rider (*Id.* at 9-10). OEG also disputes Staff's proposal to lower the IRP-D credit to the capacity rate charged to CRES providers, as the credit is only available to SSO customers, and not customers of CRES providers (OEG Br. at 16-21).

The Commission finds the IRP-D credit should be approved as proposed at $8.21/kW-month. In light of the fact that customers receiving interruptible service must be prepared to curtail their electric usage on short notice, we believe Staff's proposal to lower the credit amount to $3.34/kW-month understates the value interruptible service provides both AEP-Ohio and its customers. In addition, the IRP-D credit is beneficial in that it provides flexible options for energy intensive customers to choose their quality of service, and is also consistent with state policy under Section 4928.02(N), Revised Code, as it furthers Ohio's effectiveness in the global economy. In addition, since AEP-Ohio may utilize interruptible service as an additional demand response resource to meet its capacity obligations, we direct AEP-Ohio to bid its additional capacity resources into PJM's base residual auctions held during the ESP.

The Commission agrees with several parties who correctly pointed out that the IRP-D credit should not be tied to the RSR. As we will discuss below, the RSR is tied to rate certainty and stability, and while we have no qualms in finding that the IRP-D is reasonable, it is more appropriate to allow AEP-Ohio to recover any costs associated with the IRP-D under the EE/PDR rider. As the IRP-D will result in reducing AEP-Ohio's peak demand and encourage energy efficiency, it should be recovered through the EE/PDR rider.

6. <u>Retail Stability Rider</u>

In its modified ESP, AEP-Ohio proposes a non-bypassable RSR. AEP-Ohio states the RSR is justified under Section 4928.143(B)(2)(d), Revised Code, as it promotes stability and certainty with retail electric service, and Section 4928.143(B)(2)(e), Revised Code, which allows for automatic increases or decreases by revenue decoupling mechanisms that relate to SSO service. AEP-Ohio provides that in addition to the RSR's promotion of rate stability and certainty, it is essential to ensure the Company does not suffer severe financial repercussions as a result of the proposed ESP's capacity pricing mechanism.

AEP-Ohio witness William Avera explains that the Commission has the duty to ensure there is not an unconstitutional taking that may result in material harm to AEP-Ohio (AEP-Ohio Ex. 150 at 4-6). Dr. Avera stresses that not only does the Commission maintain this obligation to avoid confiscation, but in the event the rate plan is confiscatory, AEP-Ohio's credit rating would likely drop, limiting the ability to attract future capital investments (*Id.*).

The proposed RSR functions as a generation revenue decoupling charge that all shopping and non-shopping customers would pay through June 2015. As proposed, the RSR relies on a 10.5 percent return on equity to develop the non-fuel generation revenue target of $929 million per year, which, throughout the term of the modified ESP, would collect approximately $284 million in revenue (AEP-Ohio Ex. 100, 116 at WAA-6). In establishing the 10.5 percent target, AEP-Ohio witness William Allen considered CRES capacity revenues as based on the proposed two-tiered capacity mechanism, auction revenues, and credit for shopped load to determine where the RSR should be set. AEP-Ohio notes that while the RSR is designed to produce consistent non-fuel generation revenues, the RSR does not guarantee a company total ROE of 10.5 percent, as there are other factors affecting total company earnings, which AEP-Ohio witness Sever estimated at 9.5 percent and 7.6 percent (AEP-Ohio Ex. 151 at 2-4, AEP-Ohio Ex. 108 at OJS-2). Thus, AEP-Ohio explains the RSR only ensures a stable level of revenues during the term of the ESP, not a stable ROE (*Id.* at 3). For every $10/MW-day decrease in the Tier 2 price for capacity, Mr. Allen explains the RSR would increase by $33M (or $.023/MWh) (AEP-Ohio Ex. 116 at 14-15). Mr. Allen explains that the $3 shopped load credit is based on AEP-Ohio's estimated margin it earns from off-system sales (OSS) made as a result of MWh freed as a result of customer shopping. In his testimony, Mr. Allen provides that AEP-Ohio only retains 40 percent of the OSS margins due to its participation in the AEP pool, and of that 40 percent only 50 to 80 percent of reduced retail sales result in additional OSS, thus demonstrating the $3/MWh credit is reasonably based on appropriate OSS assumptions (AEP-Ohio Ex. 151 at 5-8).

In designing the RSR, AEP-Ohio explains that a revenue target is preferable to an earnings target, as decoupling will provide greater stability and certainty for customers and is easier to objectively measure and audit as compared to earnings, which are prone to litigation as evidenced by SEET proceedings (AEP-Ohio Ex. 116 at 13-16). AEP-Ohio believes a revenue target provides for risks associated with generation operations to be on AEP-Ohio while avoiding the need for evaluating returns associated with a deregulated entity after corporate separation (*Id.*) As proposed, the RSR would average $2/MWh (*Id.* at WAA-6).

AEP-Ohio believes the RSR is beneficial in that it freezes non-fuel generation rates and allows for AEP-Ohio's transition to a fully competitive auction by June 2015 (AEP-Ohio Ex. 119 at 2-4). AEP-Ohio opines that the RSR mechanism reflects a careful balance that will encourage customer shopping through discounted capacity prices while retaining reasonable rates for SSO customers and ensure that AEP-Ohio is not financially harmed as it transitions towards a competitive auction (*Id.*). AEP-Ohio also touts an increase in its interruptible service (IRP-D) credit upon approval of the RSR. AEP-Ohio witness Selwyn Dias explains that the increase in the IRP-D credit will benefit numerous major employers in the state of Ohio and promote economic development opportunities within AEP-Ohio's service territory (*Id.* at 7).

Without the Commission's approval of the RSR as proposed, AEP-Ohio claims that the modified ESP would result in confiscatory rates. In his rebuttal testimony, Mr. Allen argues that if the established capacity charge is below AEP-Ohio's costs, AEP-Ohio will face an adverse financial impact (AEP-Ohio Ex. 151 at 9). As such, AEP-Ohio points out that the 10.5 percent return on equity used to develop the RSR's target revenue is not only appropriate to prevent financial harm but is also necessary to avoid violating regulatory standards addressing a fair rate of return. Mr. Allen contends that the non-fuel generation revenue, which the RSR addresses, is separate and distinct from the total company earnings, which are not addressed by the RSR. This distinction, Mr. Allen states, shows the 10.5 percent return on equity is appropriate for the RSR because when the RSR is combined with total company earnings, AEP-Ohio would be looking at a total company return on equity of 7.5 percent in 2013. Therefore, AEP-Ohio argues it would be inappropriate to allow a RSR rate of return of less than 10.5 percent, as any reduction would lower the total company return on equity downward from 7.5 percent, harming AEP-Ohio's ability to attract capital and potentially putting the company in an adverse financial situation (*Id.* at 4-5).

DER, DECAM, FES, NFIB, OCC, and IEU all contend that the RSR lacks statutory authority to be approved. FES claims that Section 4928.143(B)(2)(d), Revised Code, only authorizes charges that provide stability and certainty regarding retail electric service, which AEP-Ohio has failed to show. OCC witness Daniel Duann argues that the RSR will raise customer rates and cause financial uncertainty to all native load customers (OCC Ex. 111 at 10). OCC contends that even if the RSR provided certainty and stability, it does not qualify as a term, condition, or charge pursuant to Section 4928.143(B)(2)(d), Revised Code (OCC Br. at 40). IEU and Exelon also argue the RSR violates Section 4928.02(H) Revised Code, as it would be tied to a distribution rate based on its charge to shopping customers despite the fact it is a non-bypassable charge designed to recover generation related costs (IEU Br. at 63-64, Exelon Br. at 12).

IEU, Ohio Schools, Kroger, and DECAM/DER argue that AEP-Ohio is improperly utilizing the RSR to attempt to recover transition revenue. IEU notes that AEP-Ohio's attempt to recover generation-related revenue that may not otherwise be collected by statute is an illegal attempt to recover transition revenue (IEU Ex. 124 at 4-10, 24-26). Kroger and Ohio Schools point out that not only has the opportunity to recover generation transition costs expired with the establishment of electric retail competition in 2001, AEP-Ohio waived its right to generation transition costs when it stipulated to a resolution in Case Nos. 99-1729 and 99-1730 (Kroger Br. at 3-5, Ohio Schools Br. at 18-20). Exelon and FES maintain the RSR is anticompetitive and would stifle competition.

Ormet, OCC, Ohio Schools, OEG, and Exelon indicate that, if the RSR is approved, it should contain exemptions for certain customer classes. Ohio Schools request an exemption from the RSR, pointing out that not only are schools relying on limited funding, but also that the Commission has traditionally considered schools to be a distinct customer class that is entitled to special rate treatment (Ohio Schools Br. at 22-30, citing to Case Nos. 90-717-EL-ATA, 95-300-EL-AIR, 79-629-TP-COI, Ohio Schools Ex. 103, and Tr. XVI at 4573-4574). Exelon believes the RSR should not apply to shopping customers and should be bypassable. While Exelon notes it does not oppose affording AEP-Ohio protection as it transitions its business structure, witness David Fein argues that shopping customers will unfairly be forced pay both the CRES provider and AEP-Ohio for generation (Exelon Ex. 101 at 13-14).

On the contrary, Ormet believes the RSR should not apply to customers like Ormet who cannot shop, as Ormet neither causes costs associated with the RSR nor can Ormet receive the benefits associated with it (Ormet Ex. 106 at 15-17). Ormet maintains that the RSR, as currently proposed, violates cost causation principles (*Id.*). OCC and OEG suggest that if the RSR is approved, it should not be charged to SSO customers, as these customers are not the cause of the RSR costs, and it would be unfair to force these customers to subsidize shopping customers and CRES providers (OEG Br. at 5-6, OCC Ex. 111 at 16-17).

While OEG does not support the creation of the RSR, it understands the Commission may need to provide a means to ensure AEP-Ohio has the ability to attract capital, and as such suggests that the Commission look to AEP-Ohio actual earnings as opposed to revenue (OEG Ex. 101 at 12-18). OEG argues that the RSR's use of revenues does not accurately reflect a utility's financial condition or ability to attract capital in the way that earnings do, as evidenced by earnings being the foundation used by credit agencies to determine bond ratings (*Id.*). OEG witness Lane Kollen points out that revenues are just a single component of AEP-Ohio's earnings and do not reflect a full picture of AEP-Ohio's financial health (*Id.*). Mr. Kollen suggests that if the Commission were to look at AEP-Ohio's earnings, an appropriate return on equity (ROE) would be between seven percent and 11 percent (OEG Ex. at 4-6). If the Commission were to use revenues to determine AEP-Ohio's ROE, as proposed in the RSR, Mr. Kollen believes the ROE should be at seven percent, as it is still double the cost of AEP-Ohio's long-term debt and falls within the Ohio Supreme Court's zone of reasonableness (*Id.* at 7, Tr. X at 2877-79).

In the event the Commission adopts RPM priced capacity, RESA also supports the use of earnings as opposed to revenues in calculating the RSR in the event it is necessary to avoid confiscatory rates (RESA Ex. at 11, Br. at 13-16). RESA also suggests the Commission consider projecting an amount of money necessary for AEP-Ohio to earn a reasonable rate of return and set the RSR accordingly (RESA Br. at 14-16). RESA maintains that either of these alternatives may reduce the possibility that AEP-Ohio and its new affiliate make uneconomic investments or other risks that may result from AEP-Ohio receiving a guarantee of a certain level of annual income (*Id.*). NFIB and OADA express similar concerns that the RSR, as proposed, creates no incentive for AEP-Ohio to limit its expenses (NFIB Br. at 4-6, OADA Br. at 2-3).

In addition, several other parties suggest modifications to the RSR, including its proposed ROE. Ormet states that the 10.5 percent ROE is excessive and unreasonably high. Ormet witness John Wilson explained that AEP-Ohio failed to sustain its burden of showing 10.5 percent ROE was just and reasonable, and upon utilizing Staff's methodology in 11-351-EL-AIR, determined that, based on current economic conditions and AEP-Ohio and comparable utility financial figures, an appropriate ROE would be between eight and nine percent (Ormet Ex. 107 at 8-30). Kroger witness Kevin Higgins testified that the average ROE for electric utilities is 10.2 percent, and based on the fact that AEP-Ohio's proposed two-tier capacity mechanism is above market, the ROE should be below 10.2 percent (Kroger 101 at 10). FES and Wal-Mart state that AEP-Ohio failed to justify its 10.5 percent figure, with Wal-Mart witness Steve Chriss suggesting the ROE be no higher than 10.2 percent (Wal-Mart Ex. 101 at 8-9, FES Ex. 102 at 79-80).

OCC recommends that the Commission allocate the RSR in proportion to each class share of the switched kWh sales as opposed to customer class contribution to peak load, as an allocation based on contribution to peak load is not just and reasonable (OCC Ex. 110 at 8-9). OCC witness Ibrahim points out that the residential customer class share of switched kWh sales is only eight percent, thus, if the Commission reallocates RSR costs, residential customer increases would drop from six percent to three percent (*Id.* at 24-26). Kroger argues the RSR allocates costs to customers by demand, but recovers through an energy cost, resulting in cross subsidies amongst customers (Kroger Ex. 101 at 8). Kroger recommends that costs and charges should be aligned and based on demand as opposed to energy usage (*Id.*)

OCC, FES, and Ormet also submit modifications related to the calculation AEP-Ohio's shopping credit included within the RSR calculation. Ormet argues that AEP-Ohio underestimates its $3 shopping credit. Ormet states that based on AEP-Ohio's 2011 resale percentage of 80 percent, the actual shopping credit increases to $3.75 MWh, with the total amount increasing to $78.5 million (Ormet Br. at 10-12, citing to Tr. XVII at 4905). Ormet also shows that AEP-Ohio will not need to reduce the credit by 60 percent beginning in 2013, as AEP-Ohio will no longer be in the AEP pool, resulting in the credit increasing to

$6.50 per year in 2014 and 2015 (*Id.*). OCC also points out that the shopping credit should increase based on AEP-Ohio's 2011 shopping percentage, as well as the termination of the AEP pool agreement, and recommends the Commission adopt a shipping credit higher than $3/MWh but less than $12/MWh (OCC Br. at 49-54).

The Commission finds that, upon review of the record, it is apparent that no party disputes that the approval of the RSR will provide AEP-Ohio with sufficient revenue to ensure it maintains its financial integrity as well as its ability to attract capital. There is dispute, however, as to whether the RSR is statutorily justified, and, if it is justified, the amount AEP-Ohio should be entitled to recover, and how the recovery should be allocated among customers. The Commission must first determine whether RSR mechanism is supported by statute. Next, if we find that the Commission has the authority to approve the RSR, we must balance how much cost recovery, if any, should be permitted to ensure customers are not paying excessive costs but that the recovery is enough to allow AEP-Ohio to freeze its base generation rates and maintain a reasonable SSO plan for its current customers as well as for any shopping customers that may wish to return to AEP-Ohio's SSO plan.

In beginning our analysis, we first look to AEP-Ohio's justification of the RSR. While AEP-Ohio argues there are numerous statutory provisions that may provide support for the RSR, the thrust of its arguments in support of the RSR pertain to Section 4928.143(B)(2)(d), Revised Code, which AEP-Ohio notes is met by the RSR's promotion of rate stability and certainty. AEP-Ohio also suggests that Section 4928.143(B)(2)(e), Revised Code, which allows for automatic increases or decreases, justifies the RSR, as its design includes a decoupling mechanism.

Pursuant to Section 4928.143(B)(2)(d), Revised Code, an ESP may include terms, conditions, or charges relating to limitations on customer shopping for retail electric generation that would have the effect of stabilizing retail electric service or provide certainty regarding retail electric service. We believe the RSR meets the criteria of Section 4928.143(B)(2)(d), as it promotes stable retail electric service prices and ensures customer certainty regarding retail electric service. Further, it also provides rate stability and certainty through CRES services, which clearly fall under the classification of retail electric service, by allowing customers the opportunity to mitigate any SSO increases through increased shopping opportunities that will become available as a result of the Commission's decision in the Capacity Case.

In addition, we find that the RSR freezes any non-fuel generation rate increase that might not otherwise occur absent the RSR, allowing current customer rates to remain stable throughout the term of the modified ESP. While we understand that the non-bypassable components of the RSR will result in additional costs to customers, we believe any costs associated with the RSR are mitigated by the effect of stabilizing non-fuel generation rates, as well as the guarantee that, in less than three years, AEP-Ohio will establish its pricing based on energy and capacity auctions, which this Commission again maintains is extremely beneficial by providing customers with an opportunity to pay less for retail electric service than they may be paying today.

Therefore, we find that the RSR provides certainty for retail electric service, as is consistent with Section 4928.143(B)(2)(d), Revised Code. Until May 31, 2015, AEP-Ohio's SSO rate, as a result of this RSR, will remain available for all customers, including those who are presently shopping, as well as those who may shop in the future. The ability for AEP-Ohio to maintain a fixed SSO rate is valuable, particularly if an unexpected, intervening event occurs during the term of the ESP, which could have the effect of increasing market prices for electricity. The ability for all customers within AEP-Ohio's service territory to have the option to return to AEP-Ohio's certain and fixed rates allows customers to explore shopping opportunities. This is an extremely beneficial aspect of the RSR and is undoubtedly consistent with legislative intent in providing that electric security plans may include retail electric service terms, conditions, and charges that relate to customer stability and certainty. Further, we reject the claim that the RSR allows for the collection of inappropriate transition revenues or stranded costs that should have been collected prior to December 2010 pursuant to Senate Bill 3, as AEP-Ohio does not argue its ETP did not provide sufficient revenues, and, in light of events that occurred after the ETP proceedings, including AEP-Ohio's status as an FRR entity, AEP-Ohio is able to recover its actual costs of capacity, pursuant to our decision in the Capacity Case. Therefore, anything over RPM auction capacity prices cannot be labeled as transition costs or stranded costs.

Moreover, we find that the certainty and stability the RSR provides would be all but erased by its design as a decoupling mechanism. We agree with OCC that the ability for AEP-Ohio to decouple the RSR would cause financial uncertainty, as truing up or down each year will create customer confusion in their rates. NFIB, OADA, and RESA correctly raise concerns that the RSR design creates no incentive for AEP-Ohio to limit its expenses and the Company may make uneconomic investments by its guaranteed level of annual income. While AEP-Ohio should have the opportunity to earn a reasonable rate of return, there is not a right to a guaranteed rate of return, and we will not allow AEP-Ohio to shift its risks onto customers. Thus, because its design may lead to a perverse outcome of AEP-Ohio making imprudent decisions, we find it necessary to remove the decoupling component from the RSR.

Although the RSR is justified by statute, AEP-Ohio has failed to sustain its burden of proving that its revenue target of $929 million is reasonable. The basis of AEP-Ohio's $929 million target is to ensure that its non-fuel generation revenues are stable and that stability may be ensured through a 10.5 percent ROE. However, as we previously established, it is inappropriate to guarantee a rate of return for AEP-Ohio, therefore, we find it more appropriate to establish a revenue target that will allow AEP-Ohio the opportunity to earn a reasonable rate of return. We note that our analysis of an ROE is not to guarantee a rate of return, as evidenced by the removal of the decoupling components but rather to determine a revenue target that adequately ensures AEP-Ohio can keep its base generation rates frozen and maintain its financial health. Although we believe the more appropriate method to balance these factors would have been through the use of actual dollar figures that relate to stability, because AEP-Ohio utilized a ROE in calculating its proposals, and parties responded with alternative ROE proposals, the record limits us to this approach. Therefore, in determining an appropriate quantification for the RSR, we will consider a ROE of the non-fuel generation revenue only for the purpose of creating an appropriate revenue target that will ensure AEP-Ohio has sufficient capital while maintaining its frozen base generation rates.

Only three witnesses, AEP-Ohio witness Avera, OEG witness Kollen, and Ormet witness Wilson, developed thorough testimony exploring how an appropriate revenue target for the RSR should be established, all of which were driven by an analysis of AEP-Ohio's ROE. Although OEG witness Kollen proposed a mechanism driven by adjusting AEP-Ohio's ROE upward or downward if it does not fall within a zone of reasonableness, Mr. Kollen established that anything between seven and 11 percent could be deemed reasonable (OEG Ex. 101 at 8-9). Mr. Kollen preferred focusing on a zone of reasonableness, but notes that if the Commission preferred to establish a baseline revenue target, it should be set at $689 million (*Id.* at 16-18). Ormet witness Wilson utilized Staff models from Case No. 11-351 including discounted cash flow and capital asset pricing models, and updated calculations in the Staff models to reflect current economic factors, reaching a conclusion that AEP-Ohio's ROE should be between eight and nine percent (Ormet Ex. 107 at 8-18). AEP-Ohio used witness Avera to rebut Dr. Wilson's testimony, noting that Dr. Wilson did not consider a sufficient number of utilities in the proxy group, and the utilities that were considered were not similarly situated to AEP-Ohio (AEP-Ohio Ex. 150 at 5-6). Based on this information, Dr. Avera recommended an ROE range of 10.24 percent to 11.26 percent (*Id.*).

The Commission finds that all three experts provide credible methodologies for determining an appropriate ROE for AEP-Ohio, therefore, we find OEG witness Kollen's zone of reasonableness of seven to 11 percent to be an appropriate starting point. We again emphasize that the Commission does not want to guarantee a ROE nor establish what an appropriate ROE would be, but rather, establish a reasonable revenue target that would allow AEP-Ohio an opportunity to earn somewhere within the seven to 11 percent range. We believe AEP-Ohio's starting point of $929 is too high, particularly in light of the fact that AEP-Ohio is entitled to a deferral recovery pursuant to the Capacity Case but that a baseline of $689 million would be too low to support the certainty and stability the RSR provides. Accordingly, we find that a benchmark shall be set in the approximate middle of this range, and the $929 million benchmark shall be adjusted downward to $826 million.

While we have revised the benchmark amount down to $826 million, we also need to revisit the figures AEP-Ohio used in determining its RSR revenue amounts. In designing the RSR benchmark, Mr. Allen focused on four areas of revenue: retail non-fuel generation revenues; CRES capacity revenues; auction capacity revenues; and credit for shopped load (AEP-Ohio Ex. at WAA-6). In calculating the inputs for these revenue figures, Mr. Allen relied on AEP-Ohio's own estimates ofshopping loads of 65 percent for residential customers, 80 percent for commercial customers, and 90 percent for industrial customers by the end of 2012 (*Id.* at 5).

However, evidence within this record indicates Mr. Allen's projected shopping statistics may be higher than actual shopping levels. On rebuttal, FES presented shopping statistics based on actual AEP-Ohio numbers provided by Mr. Allen as of March 1, 2012, and May 31, 2012 (FES Ex. 120). FES concluded that, based on AEP-Ohio's actual shopping statistics to date, Mr. Allen's figures overestimated the amount of shopping by 36 percent for residential customers, 17 percent for commercial customers, and 29 percent for industrial customers, creating a total overestimate across all customer classes of 27.54 percent. The Commission finds it is more appropriate to utilize a shopping projection which is roughly the midpoint between AEP-Ohio's shopping projections and the more conservative shopping estimates offered by FES. Therefore, we will estimate shopping in the first year at 52 percent, and then increase the shopping projections for years two and three to 62 percent and 72 percent, respectively. These numbers represent a reasonable estimate and are consistent with shopping statistics of other EDUs throughout the State (*See* FES Ex. 114).

Based upon the Commission's revised shopping projections, we need to adjust the calculation of the RSR. The record indicates that lower shopping figures will result in changes to retail generation revenues, CRES margins, and OSS margins, which affects the credit for shopped load, all resulting in an adjustment to the RSR (*See* FES Ex. 121). Our adjustments are highlighted below.

	PY 12/13	PY 13/14	PY 14/15
Retail Non-Fuel Gen Revenues	$528	$419	$308
CRES Capacity Revenues	$32	$65	$344
Credit for Shopped Load	$75	$89	$104
Subtotal	$636	$574	$757
Revenue Target	$826	$826	$826
Retail Stability Rider Amount	$189	$251	$68

All figures in millions

To appropriately correct the RSR based on more conservative shopping projections, we begin our analysis with retail non-fuel generation revenues. As the figures of $402, $309, and $182 are based on Mr. Allen's assumed shopping figures, when we adjust these figures to 52, 62, and 72 percent shopping, AEP-Ohio's revenues would increase to $528 million, $419 million, and $308 million, respectively.

Conversely, as a result of decreasing the shopping statistics, CRES capacity revenues would decrease. Assuming our shopping estimates of 52, 62, and 72 percent, as well as the use of RPM capacity prices, the CRES capacity revenues lower to $32 million, $65 million, and $344 million. Finally, we need to adjust the credit for shopped load based on the revised non-shopping assumptions. Because we assume lower shopping statistics, AEP-Ohio will have less opportunity for off-system sales due to an increased load of its non-shopping customers, which will lower the credit to $75 million, $89 million, and $104 million for each year of the modified ESP. Accordingly, upon factoring in our revised revenue benchmark based on a nine percent return on equity, we find a RSR amount of $508 million is appropriate. The $508 million RSR amount is limited only to the term of the modified ESP.

Although our corrected RSR mechanism ensures customer stability and certainty by providing a means for AEP-Ohio to move towards competitive market pricing, in addition to the $508 million RSR, which allows AEP-Ohio to maintain frozen base generation rates and an accelerated auction process, we must also address the capacity charge deferral mechanism, created in the Capacity Case. As our decision in the Capacity Case to utilize RPM priced capacity considered the importance of developing competitive electric markets, we believe it is appropriate to begin recovery of the deferral costs through AEP-

Ohio's RSR mechanism, as the RSR allows for AEP-Ohio to continue to provide certainty and stability for AEP-Ohio's SSO plan while competitive markets continue to develop as a result of RPM priced capacity. Therefore we believe it is appropriate to begin collection of the deferral within the RSR.

Based on our conclusion that a $508 million RSR is reasonable, as well as our determination that AEP-Ohio is entitled to begin recovery of its deferral, AEP-Ohio will be permitted to collect its $508 million RSR by a recovery amount of $3.50/MWh, through May 31, 2014, and $4/MWh between June 1, 2014 and May 31, 2015. The upward adjustment by 50 cents to $4/MWh reflects the Commission's modification to expedite the timing and percentage of the wholesale energy auction beginning on June 1, 2014. Of the $3.50/MWh and $4/MWh RSR recovery amounts, AEP-Ohio must allocate $1.00 towards AEP-Ohio's deferral recovery, pursuant to the Capacity Case. At the conclusion of the modified ESP, the Commission will determine the deferral amount and make appropriate adjustments based on AEP-Ohio's actual shopping statistics and the amount that has been collected towards the deferral through the RSR, as necessary. Further, although this Commission is generally opposed to the creation of deferrals, the extraordinary circumstances presented before us, which allow for AEP-Ohio to fully participate in the market in two years and nine months as opposed to five years, necessitate that we remain flexible and utilize a deferral to ensure we reach our finish line of a fully-established competitive electric market.

Any remaining balance of this deferral that remains at the conclusion of this modified ESP shall be amortized over a three year period unless otherwise ordered by the Commission. In order to ensure this order does not create a disincentive to shopping, at the end of the term of the ESP, AEP-Ohio shall file its actual shopping statistics in this docket. To provide complete transparency as well as to allow for accurate deferral calculations, AEP-Ohio should maintain its actual monthly shopping percentages on a month-by-month basis throughout the term of this modified ESP, as well as the months of June and July of 2012. All determinations for future recovery of the deferral shall be made following AEP-Ohio's filing of its actual shopping statistics.

We believe this balance is in the best interests of both customers and AEP-Ohio. For customers, this keeps the RSR costs stable at $3.50/MWh and $4/MWh, and with $1.00 of the RSR being devoted towards paying back AEP-Ohio's deferrals, customers will avoid paying high deferral charges for years into the future. In addition, our modifications to the RSR will provide customers with a stable rate that will not change during the term of the ESP due to the elimination of the decoupling components of the RSR. Further, as result of the Capacity Case, customers may be able to lower their bill impacts by taking advantage of CRES provider offers allowing customers to realize savings that may not have otherwise occurred without the development of a competitive retail market. In addition, this mechanism is mutually beneficial for AEP-Ohio because the RSR will ensure

AEP-Ohio has sufficient funds to maintain its operations efficiently and revise its corporate structure, as opposed to a deferral only mechanism.

Finally, we find that the RSR should be collected as a non-bypassable rider to recover charges per kWh by customer class, as proposed. We note that several parties pitched reasons as to why certain customers classes should be excluded, but we believe these arguments are meritless. Ormet contends that the RSR should not apply to customers like Ormet who cannot shop. Interestingly, Ormet again tries to play both sides of the table, forgetting that it is the beneficiary of a unique arrangement that results in Ormet receiving a discount at the expense of other AEP-Ohio customers. We reject Ormet's argument, and note that while Ormet cannot shop pursuant to its unique arrangement, it directly benefits from AEP-Ohio's customers receiving stability and certainty, as these customers ultimately pay for Ormet's discounted electricity. We also find Ohio Schools' request to be excluded from the RSR to be without merit, as it too would result in other AEP-Ohio customers, including taxpayers that already contribute to the schools, paying significantly higher shares of the RSR. It is unreasonable to make AEP-Ohio's customers pay the schools twice.

In addition, in light of the fact that the Commission has established a revenue target to be reached through the RSR in this proceeding, the Commission finds that it is also appropriate to establish a significantly excessive earnings test (SEET) threshold to ensure that the Company does not reap disproportionate benefits from the ESP. The evidence in the record demonstrates that a 12 percent ROE would be at the high end of a reasonable range for return on equity (OEG Ex. 101 at 4-6; Kroger 101 at 10; Ormet Ex. 107 at 8-30; Wal-Mart Ex. 101 at 8-9, FES Ex. 102 at 79-80), and even AEP-Ohio witness Allen agreed that a ROE of 10.5 percent is appropriate. Accordingly, for purposes of this ESP, the Commission will establish a SEET threshold for AEP-Ohio of 12 percent.

Likewise, multiple parties argue that either shopping customers or SSO customers should be excluded from paying the RSR. For non-shopping customers, the RSR provides rate stability and certainty, and ensures all SSO rates will be market-based by June 2015. For shopping customers, the RSR not only keeps a reasonably priced SSO offer on the table in the event market prices increase, but it also enables CRES providers to provide offers that take advantage of current market prices, which is a benefit for shopping customers. Accordingly, we find the RSR, as justified by Section 4928.143(b)(2)(d), Revised Code is just and reasonable, and should be non-bypassable.

Finally, the Commission notes that our determination regarding the RSR is heavily dependent on the amount of SSO load still served by the Company. Accordingly, in the event that, during the term of the ESP, there is a significant reduction in non-shopping load for reasons beyond the control of the Company, other than for shopping, the

Company is authorized to file an application to adjust the RSR to account for such changes.

7. Auction Process

As part of its modified ESP, AEP-Ohio proposes a transition to a fully-competitive auction based SSO format. The first part of AEP-Ohio's proposal includes an energy-only, slice-of system auction of five percent that will occur prior to AEP-Ohio's SSO energy auction. The energy-only slice-of-system auction would commence upon a final order in this proceeding and the corporate separation plan, with the delivery period to extend to December 31, 2014 (AEP-Ohio Ex. 101 at 20-21). AEP-Ohio notes that specific details would be addressed upon the issuance of final orders in this proceeding (*Id*).

AEP-Ohio's transition proposal also includes a commitment to conduct an energy auction for 100 percent of the SSO load for delivery in January 2015. By June 1, 2015, AEP-Ohio will conduct a competitive bid procurement (CBP) process to commit to an energy and capacity auction to service its entire SSO load (*Id.* at 19-21, AEP-Ohio Ex. 100 at 10-11). AEP-Ohio witness Powers explained that the June 1, 2015 energy and capacity auction will permit competitive suppliers and marketers to bid into AEP-Ohio's load, as its FRR obligation will be terminated (*Id.*). AEP-Ohio anticipates the CBP process will be similar to other Ohio utility CBP filings, and explains that specific details of the CBP will be addressed in a future filing.

AEP-Ohio explains that the June 1, 2015, date to service its entire SSO load by auction is based on the need for AEP's interconnection pool to be terminated and AEP-Ohio's corporate separation plan being approved. AEP-Ohio witness Philip Nelson explains that an SSO auction occurring prior to pool termination may expose AEP-Ohio to significant financial harm, and if the auction occurs prior to corporate separation, it is possible that AEP-Ohio's generation may not be utilized in the auction (AEP-Ohio Ex. 103 at 8). Further, AEP-Ohio points out that a full auction prior to June 1, 2015, would conflict with its FRR commitment that continues until May 31, 2015 (AEP-Ohio Reply Br. at 46).

FES and DER/DECAM argue that AEP-Ohio could hold an immediate CBP without waiting for pool termination and corporate separation. FES witness Rodney Frame testified that the AEP pool agreement contains no provisions that would prevent a CBP (FES Ex. 103 at 3). DER/DECAM provide that a delay in the implementation of the CBP process harms customers by preventing them from taking advantage of the current market rates (DECAM Ex. 101 at 5).

Other parties, including RESA and Exelon, propose modifications to AEP-Ohio's proposed auction process. Exelon believes the first energy and capacity auction for the SSO load should be accelerated to June 1, 2014, in order to permit customers to take advantage of competition. Exelon witness Fein notes the June 1, 2014 date would be six months after the date by which AEP-Ohio indicated its corporate separation and pool termination would be completed (Exelon Ex. 101 at 15-20). RESA makes a similar proposal, but that a June 1, 2014, auction be energy only, as this still allows AEP-Ohio six months to prepare for auction and provides customers with the benefits associated with a competitive market (RESA Br. at 16-17). On the contrary, OCC argues the interim auctions to be held during the first five months of 2015 would be detrimental to residential customers, and suggests that the Commission adopt a different approach (OCC Br. at 100-103). OCC contends that competitive market prices in 2015 may be higher than prices that would result from AEP-Ohio continuing to purchase energy from its affiliate, and recommends that the Commission require the agreement between AEP-Ohio and its affiliate to continue during the first five months of 2015, or, in the alternative, AEP-Ohio should purchase SSO capacity from its generation affiliate at RPM prices (*Id.* at 103).

In addition, Exelon also recommends that the Commission direct AEP-Ohio to conduct its CBP in a manner that is consistent with the processes that Duke Energy Ohio and FirstEnergy used in their most recent auctions. Exelon sets forth that establishing details of the CBP process in a timely manner will expedite AEP-Ohio's transition to competition and ensure there are no delays associated with settling these issues in later proceedings. Specifically, Exelon proposes that the CBP should be consistent with statutory directives set forth in Section 4928.142, Revised Code, and should ensure the dates for procurement events do not conflict with dates of other default service procurements conducted by other EDUs. Exelon warns that if the substantive issues of the procurement process are left open for interpretation, there may be uncertainty that could limit bidder participation and lead to less efficient prices. Exelon also recommends that the Commission ensure the CBP process is open and transparent by having substantive details established in a timely manner (Exelon Ex. 101 at 20-31).

The Commission finds that AEP-Ohio's proposed competitive auction process should be modified. First, we believe AEP-Ohio's energy only slice-of-system of five percent of the SSO load is too low, as AEP-Ohio will be at full energy auction by January 1, 2015, and the slice-of-system auctions will not commence until six months after the corporate separation order is issued. Accordingly, we find that increasing the percentage to a 10 percent slice-of-system auction will facilitate a smoother transition to a full energy auction.

Second, this Commission understands the importance of customers being able to take advantage of market-based prices and the benefits of developing a healthy competitive market, thus we reject OCC's arguments, as slowing the movement to competitive auctions would ultimately harm residential customers by precluding them from enjoying any benefits from competition. Based on the importance of customers having access to market-based prices and ensuring an expeditious transition to a full energy auction, in addition to making the modified ESP more favorable than the results that would otherwise apply under Section 4928.142, Revised Code, we find that AEP-Ohio is capable of having an energy auction for delivery commencing on June 1, 2014. Therefore, we direct AEP-Ohio to conduct an energy auction for delivery commencing on June 1, 2014, for 60 percent of its load, and delivery commencing on January 1, 2015, for the remainder of AEP-Ohio's energy load. AEP-Ohio's June 1, 2015, energy and capacity auction dates are appropriate and should be maintained. In addition, nothing within this Order precludes AEP-Ohio or any affiliate from bidding into any of these auctions.

Finally, we agree with Exelon that the substantive details of the CBP process need to be established to maximize the number of participants in AEP-Ohio's auctions through an open and transparent auction process. We direct AEP-Ohio to establish a CBP process consistent with Section 4928.142, Revised Code, by December 31, 2012. The CBP should include guidelines to ensure an independent third party is selected to ensure there is an open and transparent solicitation process, a standard bid evaluation, and clear product definitions. We encourage AEP-Ohio to look to recent successful CBP processes, such as Duke Energy-Ohio's, in formulating its CBP. Further, AEP-Ohio is ordered to initiate a stakeholder process within 30 days from the date of this opinion in order.

8. <u>CRES Provider Issues</u>

The modified application includes a continuation of current operational switching practices, charges, and minimum stay provisions related to the process in which customers can switch to a Competitive Retail Electric Service (CRES) provider and subsequently return to the SSO rates (AEP-Ohio Ex. 111 at 4). AEP-Ohio points out that the application includes beneficial modifications for CRES providers and customers, including the addition of peak load contribution (PLC) and network service peak load (NSPL) information to the master customer list. AEP-Ohio witness Roush testified that AEP-Ohio also eliminates the 90-day notice requirement prior to enrolling with a CRES provider, the 12 month stay requirements for commercial and industrial customers that return to SSO rates beginning January 1, 2015, and requirements for residential and small commercial customers that return to SSO rates be required to stay on the SSO plan until April 15th of the following year, beginning on January 1, 2015 (*Id.*)

Exelon argues that AEP-Ohio needs to make additional changes in order to develop the competitive market. Specifically, Exelon requests the Commission implement rate and bill ready billing and a standard purchase of receivables (POR) program, eliminate the 90-day notice requirement immediately, and implement a process to provide CRES providers with data relating to PLC and NSPL values. Exelon witness Fein recommends that, consistent with the Duke ESP order, the Commission order AEP-Ohio provide via electronic data interchange, pertinent data including historical usage and historical interval data, NSPL and PLC data, and provide a quarterly updated list for CRES providers to show accounts that are currently enrolled with the CRES provider. (Exelon Ex. 101 at 33-34). Exelon maintains that this information will allow CRES providers to more effectively serve customers and result in cost efficient competition (*Id.*) Mr. Fein further provides that clear implementation tariffs will lower costs for customers, plainly describe rules and contract terms, and allow both CRES providers and customers to easily understand AEP-Ohio's competitive process (*Id.* at 35-36).

RESA and IGS provide that AEP-Ohio's billing system is confusing to customers and creates numerous problems for CRES providers, all of which may be corrected through the implementation of a POR program that would provide customers with a single bill and collection point (RESA Ex. 101 at 12-17, IGS Ex. 101 at 15). IGS witness Parisi points out that switching statistics of natural gas utilities and Duke have increased upon the implementation of POR programs (IGS Ex. 1-1 at 18-19). RESA witness Rigenbach also recommends that the Commission direct AEP-Ohio to develop a web-based system to provide CRES providers access to customer usage and account data by May 31, 2014 (RESA Ex. 101 at 12-13). RESA and DER/DECAM also recommend that AEP-Ohio reduce or eliminate customer switching fees, as well as customer minimum stay periods (*Id.*, DER Ex. 101 at). FES witness Banks noted that the fees and minimum stay requirements hinders competition by making it difficult for customers to switch (FES Ex. 105 at 31).

While the Commission supports AEP-Ohio's provisions that encourage the development of competitive markets, modifications need to be made. AEP-Ohio witness Roush notes that customer PLC and NSPL information will be included in the master customer list, AEP-Ohio fails to make any commitment to the time frame this information would become available, nor the specific format in which customers would be able to access this data. We note that recent updates have been revised to the electronic data interchange (EDI) standards developed by the Ohio EDI Working Group (OEWG). This Commission values the efforts of OEWG in developing uniform operational standards and we expect AEP-Ohio to follow such standards and work within the group to implement solutions which are fair and reasonable, and do not discriminate against any CRES provider.

Accordingly, we direct AEP-Ohio to develop an electronic system to provide CRES providers access to pertinent customer data, including, but not limited to, PLC and NSPL values and historical usage and interval data no later than May 31, 2014. Within 30 days from the date of this opinion and order, we direct representatives from AEP-Ohio to schedule a meeting with members of the OEWG to develop a roadmap towards developing an EDI that will more effectively serve customers, and promote state policies in accordance with Section 4928.02, Revised Code. Further, as AEP-Ohio explains that it neither supports nor is opposed to the idea of a POR program (AEP-Ohio Reply Br. at 64-66), we encourage interested stakeholders to attend a workshop in conjunction with the five year rule review of Chapter 4901:1-10, O.A.C., as established in Case No. 12-2050-EL-ORD et al, to be held on August 31, 2012. In our recent order on FirstEnergy's electric security plan (*See* Case No. 12-1230-EL-SSO), we noted that this workshop would be an appropriate place of stakeholders in the FirstEnergy proceedings to review issues related to POR programs. Similarly, we believe this workshop would also provide stakeholders in this proceeding an opportunity to further discuss the merits of establishing POR programs for other Ohio EDUs that are not currently using them. The Commission concludes that the modified ESP's modification to AEP-Ohio's switching rules, charges, and minimum stay provisions that are set to take effect on January 1, 2015, are consistent with AEP-Ohio's previously approved tariffs. Further, as we previously established in our original opinion and order in this case, these provisions are not excessive or inconsistent with other electric distribution utilities, and will further support the development of competitive markets beginning in January 1, 2015. Therefore, we find these provisions to be reasonable.

9. Distribution Investment Rider

The Company's modified ESP application includes a Distribution Investment Rider (DIR), pursuant to the provisions of Section 4928.143(B)(2)(h) or (d), Revised Code, and consistent with the approved settlement in the Company's distribution rate case,[11] to provide capital funding, including carrying cost on incremental distribution infrastructure to support customer demand and advanced technologies. Aging infrastructure, according to AEP-Ohio, is the primary cause of customer outages and reliability issues. AEP-Ohio reasons that the DIR will facilitate and encourage investments to maintain and improve distribution reliability, align customer expectations and the expectations of the distribution utility, as well as streamline recovery of the associated costs and reduce the frequency of base distribution rate cases. Replacement of aging distribution equipment will also support the advanced technologies of gridSMART which will reduce the duration of customer outages based on preliminary gridSMART Phase 1 information. The Company argues that its existing capital budget forecast includes an annual investment in excess of $150 million plus operations and maintenance in distribution assets. The DIR mechanism, as proposed by the Company, includes components to recover property taxes, commercial activity tax, and to earn a return on plant in-service based on a cost of debt of 5.46 percent, a return on common equity of 10.2 percent utilizing a 47.72 percent debt and 52.28 percent common equity capital structure. The net capital additions to be included in the DIR reflect gross plant in-service after August 31, 2010, as adjusted for accumulated depreciation, because August 31, 2010, is the date certain in the Company's most recent distribution rate case and any increase in net plant that occurs after that date is not recovered in base rates. The Company proposes to cap the DIR mechanism at $86 million in 2012, $104 million for 2013, $124 million for 2014 and $51.7 million for the period January 1 through May 31, 2015, for a total of $365.7 million. As the DIR mechanism is designed, for any year that the Company's investment would result in revenues to be

11 *In re AEP-Ohio*, Case Nos. 11-351-EL-AIR, et al., Opinion and Order at 5-6 (December 14, 2011) in reference to paragraph IV.A.3 of the Joint Stipulation and Recommendation filed on November 23, 2011.

collected which exceed the cap, the overage would be recovered and be subject to the cap in the subsequent period. Symmetrically, for any year that the revenue collected under the DIR is less than the annual cap allowance, then the difference shall be applied to increase the cap for the subsequent period. The Company notes that the DIR revenue requirement must recognize the $62.344 million revenue credit reflected in the Commission approved Stipulation in the Company's distribution rate case.[12] As proposed by the Company, the DIR would be adjusted quarterly to reflect in-service net capital additions, excluding capital additions reflected in other riders, and reconciled for over and under recovery. The Company specifically requests through the DIR project, that when meters are replaced by the installation of smart meters, that the net book value of the replaced meter be included as a regulatory asset for recovery in a future filing. The DIR mechanism would be collected as a percentage of base distribution revenues. Because the DIR provides the Company with a timely cost recovery mechanism for distribution investment, AEP-Ohio will agree not to seek a change in distribution base rates with an effective date earlier than June 1, 2015. (AEP-Ohio Ex. 116 at 9-12; AEP-Ohio Ex. 110 at 18-19.)

The Company notes that Staff continuously monitors the Company's distribution system reliability by way of service complaints, electric outage reports and compliance provisions pursuant to Chapter 4901:1-10, O.A.C. In reliance on Staff testimony, the Company offers that the reliability of the distribution system was evaluated as a part of this case. (Staff Ex. 106 at 5-6; Tr. at 4339, 4345-4346.)

Customer expectations, as determined by AEP-Ohio, are aligned with the Company's expectations. AEP-Ohio witness Kirkpatrick offered that the updated customer survey results show that 19 percent of residential customers and 20 percent of commercial customers expect their reliability expectations to increase in the next five years. AEP-Ohio points out that when those customers are considered in conjunction with the customers who expect the utility to maintain the level of reliability, customer expectations increase to 90 percent of residential customers and 93 percent of commercial customers. AEP-Ohio states it is currently evaluating, based on several criteria, various asset categories with a high probability of failure and will develop a DIR program, with Staff input, taking into consideration the number of customers affected. (AEP-Ohio Ex. 110 at 11-19.)

OHA supports the adoption of the DIR as proposed by the Company (OHA Br. at 2). Kroger, OCC and APJN, on the other hand, ask the Commission to reject the DIR, as this case is not the proper forum to consider the recovery of distribution-related costs. Kroger, OCC and APJN reason that prudently incurred distribution costs are best considered in the context of a base distribution rate case where such cost are more thoroughly reviewed by the Commission. Kroger asserts that maintaining the distribution

12 *Id.*

system is a fundamental responsibility of the utility and the Company should continue to operate under the terms of its last distribution rate case until the next such proceeding. If the Commission elects to adopt the DIR mechanism, Kroger endorses Staff's position that the DIR be modified to account for accumulated deferred income taxes (ADIT) and accelerated tax depreciation. In addition, Kroger asserts that the DIR for the CSP rate zone and the OP rate zone are distinct and the cost of each unique service area should be maintained and the distribution costs assigned on the basis of cost causation. OCC and APJN add that the Company's reason for pursuing the DIR, as a component of the ESP rather than in the distribution case, is the expedience of cost recovery and when that rationale is considered in conjunction with the lack of detail on the projects to be covered within the DIR, suggest that the DIR is not needed. (Kroger Ex. 101 at 13-19; Kroger Reply Br. at 3-4; OCC/APJN Br. at 87-89; Tr. at 1184.)

OCC and APJN argue that in determining whether the DIR complies with the requirements of Section 4928.143(B)(2)(h), Revised Code, the Company focuses exclusively on the percentage of residential and commercial customers (71 percent and 73 percent, respectively) who do not believe that their electric service reliability expectations will increase rather than the minority of customers who expect their service reliability expectations to increase (19 percent and 20 percent, respectively). OCC and APJN note that 10 percent of residential customers and seven percent of commercial customers expect their reliability expectations to decrease over the next five years. At best, these interveners assert, the customer survey results are inconclusive regarding an expectation for reliability improvements as the majority of customers are content with the status quo. OCC and APJN state that with the lack of project details, and without providing an analysis of customer reliability expectation alignment with project cost and performance improvements, AEP-Ohio has failed to meet its burden of proof to support the DIR. Accordingly, OCC and APJN request that this provision of the modified ESP be rejected. (AEP-Ohio Ex. 110 at 11-12; OCC/APJN Br. at 987-994).

NFIB and COSE emphasize that the DIR, as AEP-Ohio witness Roush testified, would, if approved as proposed, result in General Service tariff rate customers receiving an increase of approximately 14.2 percent in distribution charges, about $2.00 monthly (NFIB/COSE Br. at 8-9;Tr. at 1162-1163).

Staff testified that consistent with the requirements of Rule 4901:1-10-10(B)(2), O.A.C., AEP-Ohio has rate zone specific minimum reliability performance standards, as measured by the customer average interruption duration index (CAIDI) and system average interruption frequency index (SAIFI).[13] According to Staff, development of each CAIDI and SAIFI takes into account the electric utility's three-year historical system performance, system design, technological advancements, the geography of the utility's

13 See *In re AEP-Ohio*, Case No. 09-756-EL-ESS, Opinion and Order (September 8, 2010).

service territory, customer perception surveys and other relevant factors. Staff monitors the utility's compliance with the reliability standards. Staff offers that based on customer surveys, 75 to 80 percent of residential and commercial customers are satisfied overall with the Company's service reliability. However, the Company's 2011 reliability measures were below their reliability measures for 2010 for CSP and the SAIFI measure was worse in 2011 than in 2010 for OP. Accordingly, Staff determined that AEP-Ohio's reliability expectations are not currently aligned with the reliability expectations of its customers. Staff further offered that a number of conditions be imposed on the Commission's approval of the DIR, including that the Company be ordered to work with Staff to develop a distribution capital plan, that the DIR mechanism include an offset for ADIT, irrespective of the Company's asserted inconsistency with the distribution rate case settlement, and that gridSMART related cost not be recovered through the DIR, so as to better facilitate the tracking of gridSMART expenditures and savings and benefits of the gridSMART project. Further, Staff proposes that AEP-Ohio be directed to make quarterly filings to update the DIR mechanism, with the filed rate to be effective, unless suspended by the Commission, 60 days after filing. The DIR mechanism, as advocated by Staff, would be subject to annual audits after each May filing and, in addition, subject to a final reconciliation filing on or about May 31, 2015. With the final reconciliation, Staff recommends that any amounts collected by AEP-Ohio in excess of the established cap be refunded to customers as a one-time credit on customer bills. (Staff Ex. 106 at 6-11; Staff Ex. 108 at 3-4; Tr. at 4398.)

AEP-Ohio disagrees with the Staff's rationale that the Company's and customer's expectations are not aligned. The Company reasons that the Staff relies on the reliability indices and the fact that the Company performed below the level of the preceding year. AEP-Ohio notes that in the most recent customer survey results, with the same questions as the prior year, the Company received an 85 percent positive rating from residential customers and a 92 percent positive rating from commercial customers for providing reliable service. Further, AEP-Ohio points out that missing one of the eight applicable reliability standards during the two year period does not, under the rules, constitute a violation. The Company also notes that the reliability standards are affected by storms, which are not defined as major storms, and other factors like tree-caused outages. (Tr. at 4344-4345, 4347, 4366-4367; OCC Ex. 113, Att. JDW-2.)

AEP-Ohio also opposes Staff's recommendation to file the DIR plan in a separate docket, subject to an adversarial proceeding. The Company expresses great concern that this recommendation, if adopted, will result in the Commission micromanaging and becoming overly involved in the "day-to-day operations of the business units within the utility."

As to Staff's and Kroger's proposal to reduce the DIR to account for ADIT, the Company responds that such an adjustment would have resulted in a reduced DIR credit if taken into account when the distribution rate case settlement was pending. AEP-Ohio argues that the decision on the DIR in the modified ESP should continue to mirror the understanding of the parties to the distribution rate case as any change would improperly impact the overall balanced ESP package. (AEP-Ohio Ex. 151 at 9-10.)

As authorized by Section 4928.143(B)(2)(h), Revised Code, an ESP may include the recovery of capital cost for distribution infrastructure investment to improve reliability for customers. A provision for distribution infrastructure and modernization incentives may, but need not, include a long-term energy delivery infrastructure modernization plan. We find that the DIR is an incentive ratemaking to accelerate recovery of the Company's investment in distribution service. In deciding whether to approve an ESP that contains any provision for distribution service, Section 4928.143(B)(2)(h), Revised Code, directs the Commission, as part of its determination, to examine the reliability of the electric utility's distribution system and ensure that customers' and the electric utility's expectations are aligned and that the electric utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

In this modified ESP, there is some disagreement between Staff and the Company whether or not AEP-Ohio's reliability expectations are aligned with the expectations of its customers. The Company focuses on customer surveys to conclude that expectations are aligned while Staff interprets the slight degradation in the reliability performance measures to indicate that expectations are not aligned. Despite the different conclusions by the Company and Staff, the Commission finds that both Staff and the Company have demonstrated that indeed, customers have a high expectation of reliable electric service. Given that customer surveys are one component in the factor used to establish the reliability indices and the slight reduction in the level of measured performance on which the Staff concludes that reliability expectations are not aligned, we are convinced that it is merely a slight difference between the Company's and customers' expectations. We also recognize that customer satisfaction is dependent on whether the customer has recently experienced any service outages and how quickly service was restored.

The Commission finds that, adoption of the DIR and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and better align the Company's and its customers' expectations. The Company appears to be placing sufficient proactive emphasis on and will dedicate sufficient resources to the reliability of its distribution system. Having made such a finding, the Commission approves the DIR as an appropriate incentive to accelerate recovery of AEP-Ohio's prudently incurred distribution investment costs. We emphasize that the DIR mechanism shall not include any gridSMART costs; the gridSMART projects shall be separate and apart from the DIR mechanism and projects. With this clarification, we believe it is unnecessary to address the Company's request to allow the remaining net book value of removed meters to be included as a regulatory asset recoverable through the DIR mechanism.

We agree with Staff and Kroger that the DIR mechanism be revised to account for ADIT. The Commission finds that it is not appropriate to establish the DIR rate mechanism in a manner which provides the Company with the benefit of ratepayer supplied funds. Any benefits resulting from ADIT should be reflected in the DIR revenue requirement. Therefore, the Commission directs AEP-Ohio to adjust its DIR to reflect the ADIT offset.

As was noted in the December 14, 2012 Order on the ESP 2, we find that granting the DIR mechanism requires Commission oversight. We believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs. AEP-Ohio is correct to aspire to move from a reactive to a more proactive replacement maintenance program. The Company is directed to work with Staff to develop a plan to emphasize proactive distribution maintenance that focuses spending on where it will have the greatest impact on maintaining and improving reliability for customers. Accordingly, AEP-Ohio shall work with Staff to develop the DIR plan and file the plan for Commission review in a separate docket by December 1, 2012.

With these modifications, we approve the DIR mechanism, and direct Staff to monitor, as part of the prudence review, by an independent auditor for in-service net capital additions and compliance with the proactive distribution maintenance plan developed with the assistance of the Staff. The proactive distribution infrastructure plan shall quantify reliability improvements expected, ensure no double recovery, and include a demonstration of DIR expenditures over projected expenditures and recent spending levels. The DIR mechanism will be reviewed annually for accounting accuracy, prudency and compliance with the DIR plan developed by the Staff and AEP-Ohio.

10. Pool Modification Rider

The modified ESP application includes the planned termination of the AEP East Pool Agreement (Pool Agreement). As a provision of this ESP, AEP-Ohio requests approval of a Pool Termination Rider (PTR), initially set at zero. If the Company's corporate separation plan filed in Case No. 12-1126-EL-UNC is approved as proposed by the Company, and the Amos and Mitchell units are transferred as proposed to AEP-Ohio affiliates, then AEP-Ohio will not seek to implement the PTR irrespective of whether lost revenues exceed $35 million annually. However, if the corporate separation plan is denied or modified, then AEP-Ohio requests permission to file for the recovery of lost revenue in association with termination of the Pool Agreement via a non-bypassable rider. The PTR, according to AEP-Ohio, is designed to offset the revenue losses caused by the termination of the Pool Agreement since a significant portion of AEP-Ohio's total revenues come from sales of power to other Pool members. The Company argues that with the termination of the Pool Agreement, the Company will need to find new or additional revenue to recover the costs of operating its generating assets, or it will need to reduce the cost associated with those assets. As AEP-Ohio claims the lost revenues[14] from capacity sales to Pool Agreement members cannot be mitigated by off-system sales in the market alone. The Company agrees that it will only seek to recover lost pool termination revenues in excess of $35 million per year during the term of the ESP. (AEP-Ohio Ex. 103 at 21-23.)

OCC, APJN, FES and IEU oppose the adoption of the PTR, as they reason there is no provision of Section 4928.143(B)(2), Revised Code, which authorizes such a charge and no Commission precedent for the PTR. IEU asserts that approval of the PTR would essentially be the recovery of above-market or transition revenue in violation of state law and the electric transition plan (ETP) Stipulations.[15] As proposed, the interveners claim that the PTR is one-sided to the benefit of the Company. FES offers that there is insufficient information in the record to allow the Commission to evaluate the terms and conditions of the PTR, as a part of the modified ESP, to require ratepayers to submit $350-$400 million over the term of the ESP. Furthermore, OCC and APJN note that the Commission has disregarded transactions related to the Pool Agreement for the purpose of considering revenue or sales margins from opportunity sales (capacity and energy) as to FAC costs or consideration of off-system sales in the evaluation of significantly excessive earnings test.[16] Accordingly, OCC and APJN reason that because the Commission has previously disregarded transactions related to the Pool Agreement, that it would be unfair and unreasonable to ensure AEP-Ohio is compensated for lost revenue based on the Pool Agreement at the cost of ratepayers. For these reasons, OCC and APJN believe the PTR should be rejected or modified such that AEP-Ohio customers receive the benefits from the Company's off-system sales. IEU says the PTR provides a competitive advantage to GenResources and, therefore, violates corporate separation requirements. (OCC/APJN Br. at 85-87; IEU Br. at 69; IEU Ex. 124 at 30-31; FES Br. at 106-109; Tr. at 582, 698.)

The Company dispels the assertion that there is no statutory basis for a pool termination cost recovery provision in an ESP on the basis that the Commission has already rejected this argument in its December 14, 2011, Order on the ESP 2, where the Commission determined a pool termination rider may be approved "pursuant to Section

14 AEP-Ohio would determine the amount of lost revenue by comparing the lost pool capacity revenue for the most recent 12 month period preceding the effective date of the change in the AEP Pool to increases in net revenue related to new wholesale transactions or decreases in generation asset costs as a result of terminating the Pool Agreement.

15 *In re AEP-Ohio*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Order (September 28, 2000).

16 *In re AEP-Ohio*, ESP I Order at 17 (March 18, 2009); *In re AEP-Ohio*, Case No. 10-1261-EL-UNC, Order at 29 (January 11, 2011).

4928.143(B), Revised Code," and further concluded that establishing a rider "at a zero rate does not violate any regulatory principle or practice."[17] According to the Company, the other criticisms that these parties raise regarding the PTR are objections as to how, or the extent to which, pool termination costs should be recoverable through the rider which are not ripe and should be addressed if, and only if, AEP-Ohio actually pursues recovery of any such costs in the future as part of a separate proceeding. (AEP-Ohio Reply Br. at 59-60.)

We find statutory support for the adoption of the PTR in Section 4928.143(B)(2)(h), Revised Code. The PTR serves as an incentive for AEP-Ohio to move to a competitive market to the benefit of its shopping and non-shopping customers, without regard to the possible loss of revenue associated with the termination of the Pool Agreement with the full transition to market for all SSO customers by no later than June 1, 2015. Therefore, we approve the PTR as a placeholder mechanism, initially established at a rate of zero, contingent upon the Commission's review of an application by the Company for such costs. The Commission notes that in permitting the creation of the PTR, it is not authorizing the recovery of any costs for AEP-Ohio, but is allowing for the establishment of a placeholder mechanism, and any recovery under the PTR must be specifically authorized by the Commission. If, and when, AEP-Ohio seeks recovery under the PTR, it will maintain the burden set forth in Section 4928.143, Revised Code. In addition, the Commission finds that in the event AEP-Ohio seeks recovery under the PTR, AEP-Ohio must first demonstrate the extent to which the Pool Agreement benefitted Ohio ratepayers over the long-term and the extent to which the costs and/or revenues should be allocated to Ohio ratepayers. Further, AEP-Ohio must demonstrate to the Commission that any recovery it seeks under the PTR is based upon costs which were prudently incurred and are reasonable. Importantly, this Commission notes that AEP-Ohio will only be permitted to requests recovery should this Commission modify or amend its corporate separation plan as filed in Case No. 12-1126-EL-UNC only as to divestiture of the generation assets; we specifically deny the Company's request for recovery through the PTR based on any other amendment or modification of the corporate separation plan by this Commission or the Federal Energy Regulatory Commission (FERC) or FERC's denial or impediment to the transfer of the Amos and Mitchell units to AEP-Ohio affiliates. As such, AEP-Ohio's right to recover lost revenues under the PTR is based exclusively on the actions, or lack thereof, of this Commission.

11. Capacity Plan

Pursuant to the Commission's Entry on Rehearing issued February 23, 2012, in the ESP 2 cases, and the Entry issued March 7, 2012, in the Capacity Case, the Commission directed that the Capacity Case proceed, without further delay, to facilitate the development of the record to address the issues raised, outside of the ESP proceeding.

17 *In re AEP-Ohio*, Case No. 11-346-EL-SSO et al., Order at 50 (December 14, 2011).

While the Capacity Case continued on an expedited schedule to determine the state compensation mechanism, AEP-Ohio nonetheless included, as a component of this modified ESP, a capacity provision different from its litigation position in the Capacity Case, which may be summarized as follows. As a component of this modified ESP, the Company proposes a two-tiered, capacity pricing mechanism, with a tier 1 rate of $145.79 per MW-day and a tier 2 rate of $255.00 per MW-day. Shopping customers, within each rate class, would receive tier 1 capacity rates in proportion to their relative retail sales level based on the Company's retail load. During 2012, 21 percent of the Company's total retail load would receive tier 1 capacity and in 2013, the percentage would increase to 31 percent. *In 2014, through the end of the ESP, May 31, 2015, the tier 1 set aside percentage* would increase to 41 percent of the Company's retail load. All other shopping customers would receive tier 2 capacity rates. For 2012, an additional allotment of tier 1 priced capacity will be available to non-mercantile customers who are part of a community that approved a governmental aggregation program on or before November 8, 2011, even if the set-aside has been exceeded. AEP-Ohio does not propose any special capacity set-aside for governmental aggregation programs after 2012. (AEP-Ohio Ex. 101 at 15; AEP-Ohio Ex. 116 at 6-7.)

AEP-Ohio argues that its embedded cost-based charge for capacity is $355.72 per MW-day, as supported by the Company in the Capacity Case. Further, AEP-Ohio projects, with forward energy pricing decreasing over the remainder of 2012 by approximately 25 percent and based upon the switching rates experienced by other Ohio electric utilities, that by the end of 2012 shopping rates in AEP-Ohio territory will increase to 65 percent of residential load, 80 percent of commercial load and 90 percent of industrial load (excluding one large customer). AEP-Ohio reasons that the two-tier capacity pricing mechanism is a discount from the Company's embedded cost of capacity which will provide CRES providers headroom, the ability to offer shopping customers lower competitive electric service rates and expand competition in the Company's service territory and, as a component of this modified ESP, balances the revenue losses likely to be experienced by the Company. Further, AEP-Ohio submits that the capacity pricing offered as a part of this modified ESP is intended to mitigate, in part, the financial harm the Company will potentially endure if the Company is required to provide capacity at PJM's RPM-based rate. (AEP-Ohio Ex. 116 at 4-5, 8-9; Tr. at 332-333.)

As an alternative to the two-tiered capacity mechanism, AEP-Ohio proposes as a component of the modified ESP, to charge CRES providers its embedded cost of capacity $355.72 per MW-day with a $10 per MWh bill credit to shopping customers, subject to a cap of $350 million through December 31, 2014. Shopping credits would be limited to up to 20 percent of the load of each customer class for June 2012 through May 2013, and increase to 30 percent for the period June 2013 through May 2014 and then to 40 percent for the period June 2014 through December 2014. AEP-Ohio's rationale for the alternative is to ensure shopping customers receive a direct and tangible benefit to shop that is fixed and known regardless of the CRES provider selected. (AEP-Ohio Ex. 116 at 15-17; Tr. at 427, 1434.)

On July 2, 2012, the Commission issued the Order in the Capacity Case (Capacity Order) wherein the Commission determined $188.88 per MW-day as the appropriate charge to enable the Company to recover its capacity costs pursuant to its Fixed Resource Requirements (FRR) obligations from CRES providers.[18] However, the Capacity Order also directed that AEP-Ohio's capacity charge to CRES providers shall be the auction-based rate, as determined by PJM via its reliability pricing model (RPM), including final zonal adjustments, on the basis that the RPM rate will promote retail electric competition.[19]

In the Capacity Order, the Commission also authorized AEP-Ohio to modify its accounting procedures to defer the incurred capacity costs not recovered from CRES providers, commencing June 1, 2012, through the end of this modified ESP, with the recovery mechanism to be established in this proceeding.[20]

In this Order on the modified ESP, the Commission adopts, as part of the RSR, the recovery of the difference between the RPM-based capacity rate and AEP-Ohio's state compensation mechanism for capacity as determined by the Commission.

Staff endorses the Company's recovery of the difference between the state compensation mechanism for capacity and the RPM rate (Staff Reply Br. at 13). On the other hand, IEU, OCC and APJN argue that there is no record evidence in this modified ESP case, or any other proceeding, to determine an appropriate mechanism to collect deferred capacity charges in contradiction of the requirements in Section 4903.09, Revised Code, and the parties were not afforded due process on the issue. Furthermore, OCC and APJN reason that the capacity charge deferrals cannot be a provision of an ESP as the charges do not fall within one of the specified categories listed in Section 4928.143(B)(2), Revised Code, and there is no statutory basis under Chapter 4928, Revised Code, for such charges. OCC and APJN also contend approval of the recovery of deferred capacity charges violates state policies expressed in Section 4928.02, Revised Code, at paragraph (A), which requires reasonably priced retail electric service; at paragraph (H), which prohibits anticompetitive subsidies from noncompetitive retail electric service to competitive retail service; and at paragraph (L), which requires the Commission to protect at-risk populations. (OCC/APJN Reply Br. at 18; IEU Reply Br. 6-7).

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18 In re Capacity Case, Order at 33-36 (July 2, 2012).

19 In re Capacity Case, Order at 23 (July 2, 2012).

20 In re Capacity Case, Order at 23 (July 2, 2012).