131 FERC ¶ 61,173
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
and John R. Norris.

Midwest Independent Transmission System Operator, Inc.	Docket Nos.	ER05-6-001, 002, 003, 005, 007, 008, 009, 013, 014, 016, 017, 018, 019, 020, 021, 022, 024, 026, 031, 034, 048, 050, 056, 113
Midwest Independent Transmission System Operator, Inc., PJM Interconnection, LLC, *et al.*	Docket Nos.	EL04-135-003, 004, 005, 007, 008, 010, 015, 016, 018, 019, 020, 021, 022, 023, 026, 028, 031, 033, 036, 052, 058, 088, 116
Midwest Independent Transmission System Operator, Inc., PJM Interconnection, LLC, *et al.*	Docket Nos.	EL02-111-020, 021, 022, 024, 026, 027, 028, 031, 033, 034, 036, 037, 038, 039, 040, 041, 042, 044, 046, 049, 051, 054, 076, 070, 105, 134
Ameren Services Company, *et al.*	Docket Nos.	EL03-212-017, 018, 019, 021, 023, 024, 025, 029, 032, 034, 035, 036, 037, 038, 040, 042, 045, 050, 066, 072, 101, 130

ORDER ON INITIAL DECISION

(Issued May 21, 2010)

Table of Contents

1. This order is before the Commission on exceptions to two partial initial decisions, issued on March 10, 2006,[1] and April 13, 2006,[2] and to an Initial Decision issued on August 10, 2006,[3] in these proceedings. The decisions address various compliance filings to implement a transitional sixteen-month lost revenue recovery mechanism that was a component of the rate design that the Commission adopted to replace rate pancaking within the combined Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, LLC (PJM) region, which the Commission had found to be unjust and unreasonable. As we explain, in this order we reverse, in part,

[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 63,037 (2006) (March 10 Partial Decision).

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 63,011 (2006) (April 13 Partial Decision).

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 63,030 (2006) (Initial Decision).

and affirm, in part, the initial decisions. We approve three settlements that were certified as contested during the hearing and were held in abeyance pending action on the initial decisions and requests for rehearing. We also approve a fourth settlement that was filed on October 29, 2009. The Commission is simultaneously issuing an order on pending requests for rehearing of various orders addressing the rate design that the Commission adopted to replace rate pancaking within the combined Midwest ISO-PJM region.

I. <u>Background</u>

2. In July 2002, the Commission accepted the choices of American Electric Power Service Corporation (AEP), Commonwealth Edison Company and Commonwealth Edison Company of Indiana (collectively, ComEd), and The Dayton Power and Light Company (Dayton) to join PJM.[4] In so doing, the Commission found that those Regional Transmission Organization (RTO) choices would result in an elongated and highly irregular seam between Midwest ISO and PJM that would "island" portions of Midwest ISO (Wisconsin and Michigan) from the remainder of Midwest ISO and would divide highly interconnected transmission systems across which substantial trade takes place. The Commission found that, without mitigation, the seam would subject a large number of transactions in the region to continued rate pancaking, impeding the goals of Order No. 2000.[5] Therefore, as a condition of accepting those RTO choices, the Commission required parties in the region to address the problem of rate pancaking across the Midwest ISO-PJM seam. Accordingly, the Commission instituted a proceeding under section 206 of the Federal Power Act (FPA)[6] to investigate the rates for service between the two RTOs and established trial-type hearing procedures.[7]

3. Following the hearing and issuance of an initial decision,[8] the Commission found the rates for service through or out of one RTO to serve load in the other RTO (i.e., regional through-and-out rates), which produced rate pancaking, unjust and

---

[4] *Alliance Co.*, 100 FERC ¶ 61,137 (2002) (Alliance 2002 Order), *order on reh'g*, 103 FERC ¶ 61,274 (2003).

[5] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[6] 16 U.S.C. § 824e (2006).

[7] Alliance 2002 Order, 100 FERC ¶ 61,137.

[8] *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 63,049 (2003).

unreasonable.[9] Two rate structures to replace inter-RTO rate pancaking were advocated in the hearing: (1) pure license plate rates[10] (advocated by the original or "classic" PJM transmission owners, a number of transmission dependent utilities in the region, and load-serving entities in Wisconsin and Michigan); and (2) license plate rates with a two-year transitional lost-revenue recovery mechanism (the Seams Elimination Charge/Cost Adjustment/Assignment (SECA))[11] (advocated by the Midwest ISO transmission owners and the former members of the proposed Alliance RTO).[12] The Commission found that mechanisms like the SECA, if properly structured, could serve as a reasonable transition mechanism to mitigate abrupt cost shifting that would otherwise occur with the replacement of rate pancaking with license plate rates. However, it found the record inadequate at that time to establish the SECA as a just and reasonable replacement rate. It, therefore, adopted a license plate rate design without the SECA, effective November 1,

---

[9] *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,105 (2003) (July 2003 Order).

[10] Under a license plate rate design, the regional footprint is segregated into a number of transmission pricing zones, typically based on the boundaries of individual transmission owners or groups of transmission owners, and customers taking transmission service for delivery to load within the region pay a rate based on the embedded cost of the transmission facilities in the transmission pricing zone where the load is located. Thus, under license plate rates, customers serving load within the region pay for the embedded cost of the transmission facilities in their local transmission pricing zone and receive reciprocal access to the entire regional grid.

[11] The SECA would be a non-bypassable surcharge to license plate zonal rates for delivery to load within the RTOs. The SECA would recover revenues that would be lost due to the elimination of rate pancaking from loads in each RTO based on the revenues received in a recent historical test period associated with transactions to serve that load. During the transition period, the load in each license plate pricing zone or subzone in the importing RTO would pay approximately the same amount in the aggregate through the SECA surcharge as had been previously paid through regional through-and-out rates for service to such load. However, the surcharges would be designed as a uniform rate to be assessed on all deliveries to loads within the zone or subzone within the importing RTO, not just those deliveries associated with through-and-out transactions.

[12] The former Alliance RTO members include: AEP, ComEd, Dayton, Illinois Power Co., Northern Indiana Public Service Co., and the operating companies of FirstEnergy Corp. and Ameren Services Co.

2003, but stated that transmission owners may pursue the SECA through filings under section 205 of the FPA.[13]

4. The Commission subsequently suspended the effective date for the elimination of rate pancaking, pending Commission action on requests for rehearing. And the Commission later granted rehearing,[14] adopting the SECA for a two-year transition period and delaying the date for the replacement of rate pancaking until April 1, 2004, to allow time for the development of SECA compliance filings. In order to minimize the amount of lost revenues to be recovered through the SECA, the Commission limited the elimination of regional through-and-out rates during the transition period to reservations pursuant to requests made on or after November 17, 2003, for service commencing on or after April 1, 2004.[15]

5. As noted above, the SECA would charge the load in the importing RTO for access to the transmission facilities of the exporting RTO in proportion to the benefits that load within the importing RTO will realize when pancaked rates are no longer paid for transmission service over the transmission facilities in the exporting RTO to serve such load. The SECA revenues would be distributed to the transmission owners in the exporting RTO to offset their cost of service otherwise born by local load through license plate rates. The load in the importing RTO would pay approximately the same amount in the aggregate through the SECA surcharge as had previously been paid to serve such load through regional through-and-out rates. However, the surcharges would be non-bypassable (i.e., they would be assessed on all deliveries by customers within the importing RTO, not only the deliveries associated with through-and-out transactions), thereby avoiding the harmful effects on economic choices caused by customers having to pay multiple charges when crossing the seam under the existing rate design. Transactions under grandfathered agreements and transactions that sink outside of the combined region (i.e., outside of the Midwest ISO-PJM footprint) would not be included in these calculations, since rate pancaking was not eliminated for such transactions. North American Electric Reliability Corporation hourly scheduling tag data would be used to identify the loads benefiting from the use of particular through-and-out transactions, and lost through-and-out revenues would be assigned to loads on the basis of such analysis.

6. As proposed by the sponsoring transmission owners, the SECA would be derived using historic test-period data and would assign lost revenue responsibility to the load in

---

[13] 16 U.S.C. § 824d (2000)

[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,212 (2003) (November 2003 Rehearing Order).

[15] *Id.* P 15.

each license plate pricing zone. Specifically, the revenue responsibility for each zone would be based on the amount of energy in megawatt hours (MWh) that sank in the zone during the test period that crossed the Midwest ISO-PJM seam (determined using tag data and excluding transactions under grandfathered agreements) multiplied by the average regional through-and-out revenues per MWh of the transmission providers involved in the transaction across the Midwest ISO-PJM seam. The zonal revenue responsibility would then be divided by the total load in the zone and firm point-to-point transactions sinking within the zone, excluding grandfathered transactions, resulting in the per-unit zonal SECA charges that would be assessed on the actual demand of each load-serving entity taking service in the zone for each month that the SECA is in effect.

7. The Commission also clarified the following specific attributes of the SECA:

Test Period: the Commission found that the SECA should be based on the most recent historical data available and required that the SECA be based on calendar-year 2002 data during the first year of the transition period and calendar-year 2003 data during the second year of the transition period, with adjustments for known and measurable differences to most closely reflect future trading patterns;[16]

Hubbing Adjustments: the Commission found that the SECA should be adjusted for so-called "hubbing" transactions where tag data shows that the transaction sank in a particular zone, but the underlying transaction actually served load in another zone, either in the same RTO or outside of the RTO; such adjustments should allocate transmission revenues associated with the transaction to the load actually served by the transaction, if the load is located within the combined region in which rate pancaking has been eliminated, or should exclude such revenues, if the load is located outside of the combined region where rate pancaking has not been eliminated;[17]

Subzones: the Commission found that the SECA obligations should be developed on a subzonal basis, reflecting the tagged schedules to each load-serving entity in a license plate pricing zone;[18]

Shift-to-Shipper Claims: the Commission provided that, as part of the compliance filing process, it will allow load-serving entities under existing

---

[16] *Id.* P 66.

[17] *Id.* P 80.

[18] *Id.* P 85.

fixed-price contracts for bundled power supply that continue into the transition period to demonstrate that the supplier is the shipper for such transactions and to propose that the supplier be required to pay the SECA charges for that portion of the load-serving entity's load served by the contract (so-called "shift-to-shipper" claims);[19] and

Existing Contract Credit: the Commission provided that load-serving entities with existing transmission arrangements that continue into the transition period, and continue to pay regional through-and-out rates, should receive adjustments to their SECA obligations necessary to prevent double recovery for such transmission.[20]

8. The Commission subsequently instituted settlement proceedings under the Presiding Judge in the winter of 2004 to help the parties resolve issues associated with the preparation of the SECA compliance filings.[21] As a result of those settlement discussions, the parties entered into a settlement, the Going Forward Principles and Procedures (Going Forward Principles),[22] which the Commission approved.[23] This settlement delayed the elimination of rate pancaking until December 1, 2004, at which time a replacement rate design that eliminates the seam must take effect, even if subject to nominal suspension and refund. The settlement committed the transmission owners to file pricing proposals under section 205 of the FPA by October 1, 2004, and also provided that "back-stop" SECA compliance filings would be made on or before November 24, 2004, to take effect subject to nominal suspension and refund on December 1, 2004, if the Commission did not otherwise put into effect a replacement rate design that eliminates seams on December 1, 2004.

9. On October 1, 2004, two pricing proposals were filed, each under section 206 of the FPA (neither group of transmission owners was able to secure the support of enough transmission owners in each RTO to file a change in regional rate design under section 205).[24] One group, representing a large majority of transmission owners and a wide

---

[19] *Id*. P 45.

[20] *Id.*

[21] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,105 (2004).

[22] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 63,024 (2004).

[23] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,262 (2004).

[24] Under the Going Forward Principles, the parties agreed to submit a long-term transmission pricing structure under section 205; and, in September 2004, the

(continued…)

cross section of other stakeholders, filed a proposal consisting of: (1) pure license plate rates for the recovery of the cost of existing facilities; (2) a commitment to develop an inter-RTO cost allocation methodology for use in recovering the cost of new cross-border facilities; and (3) an offer of lump sum settlement payments to AEP, ComEd, and Dayton to address transitional cost shifting concerns. The other proposal, made by AEP, ComEd, Dayton, and other Midwest ISO and PJM transmission owners located along the seam, consisted of a new rate design that would recover a portion of transmission costs through the existing license plate rate structure, a portion of costs through postage stamp pricing for high-voltage facilities, and a portion of costs through a flow-based allocation based on a simulated market dispatch model.

10. In its order on the two pricing proposals,[25] the Commission found that the proposal by AEP, *et al.*, was not fully supported, had not been shown to be just and reasonable, and therefore, could not be adopted and implemented to take effect on December 1, 2004. To replace rate pancaking on December 1, 2004, the Commission adopted license plate rates for the recovery of the cost of existing facilities and required the development of an inter-RTO cost allocation methodology for the pricing of new cross-border facilities built in one RTO but providing benefits to customers in the other RTO. It also rejected the contested settlement payments as unduly discriminatory and, instead, adopted the SECA as a transitional mechanism to mitigate abrupt cost shifts resulting from the replacement of rate pancaking with license plate rates. The Commission ordered compliance filings to:

> (1) reflect December 1, 2004, as the effective date for elimination of [regional] through-and-out rates for reservations pursuant to requests made on or after November 17, 2003, for service commencing on or after April 1, 2004, for transactions to serve load within the other RTO where transmission service is taken under the open access transmission tariff of the other RTO; (2) reflect April 1, 2006 as the effective date for elimination of [regional] through-and-out rates for all transactions to serve load within

---

Commission initiated a section 206 proceeding in Docket No. EL04-135-000 to ensure that the Commission had adequate authority to implement the pricing structure for all parties. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,313 (2004). The group supporting license plate rates as the replacement for regional through-and-out rates also filed, under section 205, proposed adjustments to the Midwest ISO transmission owners' zonal license plate rates under the Midwest ISO tariff to exclude credits for through-and-out revenues that would be lost due to the elimination of rate pancaking between the RTOs (this proposal initiated Docket No. ER05-6-000).

[25] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168 (2004) (November 2004 Order).

> the other RTO where transmission service is taken under the open access transmission tariff of the other RTO; and (3) incorporate the SECA mechanism as the transitional replacement rate effective December 1, 2004 through March 31, 2006.[26]

11. Upon issuance of the November 2004 Order, AEP filed a motion requesting that the Commission clarify that it may recover lost revenues associated with the elimination of intra-RTO rate pancaking within PJM through the SECA. On November 30, 2004, the Commission clarified that AEP, ComEd, and Dayton may recover these intra-RTO lost revenues through the SECA.[27]

12. In 2005, in a series of orders, the Commission accepted and set for hearing initial and revised SECA implementation filings.[28] In response to an admonition from Congress, in the joint explanatory statement in the conference report accompanying the Energy and Water Development Appropriations Act for FY 2006, that Congress expected the Commission to review its SECA policies and take expeditious and appropriate remedial steps,[29] on January 20, 2006, the Commission directed the Presiding Judge to issue an initial decision by August 11, 2006.[30]

13. Parties engaged in settlement discussions throughout the course of the hearing procedures, and some parties settled in whole or in part. In the end, the Presiding Judge ruled on the following "shift-to-shipper" claims: the claim of Michigan South Central Power Agency against Constellation Energy Commodities Group, Inc. (CCG); the claim of the City of Bay City, Michigan, (Bay City) and Michigan Public Power Rate Payers

---

[26] *Id.* P 66. December 1, 2004, through March 31, 2006, was the remainder of the two-year transition period beginning April 1, 2004, which was adopted in the November 2003 Rehearing Order.

[27] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,243, at P 9 (2004) (November 2004 Clarification Order).

[28] *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,107 (2005) (February 2005 Order); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,409 (2005) (June 2005 Order); *Midwest Indep. Transmission Sys. Operator, Inc.*, 112 FERC ¶ 61,267 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,010 (2005).

[29] H.R. Rep. No. 109-275 (2005), Cong. Rec. H9911-12 (daily ed. Nov. 7, 2005).

[30] *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,057 (2006).

Association[31] against CCG; the claim of Quest Energy, LLC against Mirant Americas Energy Marketing (MAEM); the "ripple" claim of CCG against AEP Energy Marketing (AEM); the claim of CCG against CMS Energy Resources Management Company (CMS Energy); and the claim of Bay City against CMS Energy.

14. Prior to the hearing, the Presiding Judge issued the March 10 Partial Decision[32] and the April 13 Partial Decision[33] addressing motions for summary judgment. After the hearing, the Presiding Judge issued the Initial Decision.[34] All three decisions are addressed herein.

15. Briefs on Exceptions and Briefs Opposing Exceptions to the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision were filed by the entities identified in Appendix A, and the party abbreviations listed in Appendix A will be used throughout this order.

II. Discussion

A. Introductory Summary

16. In this section, we provide a summary of the Presiding Judge's findings in the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision and our findings in this order on exceptions to the decisions.

1. March 10 Partial Decision, April 13 Partial Decision, and Initial Decision

17. The Initial Decision finds that the transmission owners fail to adequately support the claimed lost through-and-out revenues that provide the basis for calculating the SECA. It finds that the transmission owners fail to carry their burden to make adjustments to test-period data for known and measurable differences and to remove hubbing transactions, but it leaves the burden to propose and support such adjustments to customers. The Initial Decision also finds that certain transmission owners' witnesses failed to independently verify data and that certain transmission owners did not sponsor witnesses that individually supported the transmission owners' level of lost revenues.

---

[31] Michigan Public Power Rate Payers Association includes the Cities of Chelsea, Eaton Rapids, Hart, Portland, and St. Louis.

[32] March 10 Partial Decision, 114 FERC ¶ 63,037.

[33] April 13 Partial Decision, 115 FERC ¶ 63,011.

[34] Initial Decision, 116 FERC ¶ 63,030.

For these reasons, the Initial Decision finds that the claimed lost revenue amounts are invalid, and the transmission owners should be ordered to make new compliance filings that adequately support their claimed lost revenue amounts.

18. Because the elimination of rate pancaking was delayed for eight months, from April 1 until December 1, 2004, by the Going Forward Principles settlement, the SECA was only charged for the last four months (December 2004 through March 2005) of the first year of the transition period. The Initial Decision disagrees with parties that contend that, because the transmission owners already recovered revenues associated with higher volumes of reservations during the peak summer months of 2004 through the continuation of rate pancaking, including the summer months of the historical 2002 data in the SECA for the December 2004 through March 2005 period would result in double recovery. It therefore finds that the SECA for December 2004 through March 2005 should be based on the corresponding calendar months of the test year. The Initial Decision also finds that 2003 data should be used for the entire transition period because of certain anomalies and shortcomings in the quality of the 2002 data.

19. The Initial Decision finds that, while an average rate method can be a legitimate way to allocate revenue responsibility, the use of an average rate to allocate lost revenues in the compliance filings aggravates cost shifting among the transmission owners. It finds that certain PJM transmission owners' inclusion of revenues associated with in-out transactions (i.e., transactions where the tag shows that the transaction sank outside of the combined region) is not in compliance with the Commission's directives, which did not require the elimination of regional through-and-out rates for transactions that sink outside of the combined region nor the recovery of any associated lost revenues. It also rejects the inclusion of out-in revenues, which would increase SECA charges by including revenues associated with transactions that exited the combined region but then re-entered to sink within the region, finding that such adjustments are uncorroborated and would result in over recovery. In addition, it accepts hubbing adjustments proposed by parties for generation-only control areas, finding the adjustments to be correct and compliant with the Commission's previous orders.

20. The Initial Decision finds that only revenues for the single regional through-and-out rate for transmission service between the two RTOs are to be included in the SECA mechanism. The Initial Decision finds the inclusion of intra-RTO lost revenues in the SECA mechanism to be unjust and unreasonable.

21. In their compliance filings, transmission owners include revenues that they received from their merchant affiliates during the test period as lost revenues in their SECA calculations. The Initial Decision concludes that the inclusion of merchant affiliate transactions in the SECA calculations is unjust and unreasonable because it creates a financial windfall for the utility and is contrary to the Commission's finding that the SECA was not intended to provide greater revenues for the utility. Therefore, the Initial Decision finds that affiliate transactions should be excluded from the lost revenues

upon which the SECA is calculated, and the lost revenues in the compliance filings should be recalculated in accordance with this conclusion.

22. While in prior orders adopting the SECA the Commission required that SECA charges be calculated on a subzonal basis in order to best reflect the relative benefits of individual customers due to the elimination of regional through-and-out rates, the Commission also recognized that North American Electric Reliability Corporation tag data could not be used to allocate lost revenues among subzones in the PJM market during the test period (Classic PJM)[35] because tags for imports into the PJM spot market are not associated with any particular load in PJM. The Commission directed the Classic PJM entities to propose an alternate method of allocating lost revenues among load in the PJM market in proportion to the benefits that the load realized due to the elimination of rate pancaking. The PJM transmission owners' compliance filings allocate lost revenues among entities in the Classic PJM market on a load-ratio basis (i.e., without attempting to determine the relative benefits that different loads will experience). The entities in the Classic PJM market state that it is simply impossible to trace the benefits from imports to subzones in their area. The Initial Decision finds that the record as developed does not support a finding that the use of subzones produces just and reasonable results. The Initial Decision finds that the compliance filings' use of subzones in New PJM[36] but not in Classic PJM creates unjust and preferential results between Classic PJM and New PJM and that the allocation in Classic PJM does not comply with cost-causation principles. In addition, the Initial Decision finds that the record demonstrates that all of the proposed subzonal cost allocation filings fail to properly allocate charges consistent with cost-causation and benefit-derivation principles because the transmission owners have not considered the benefits that any particular subzone would expect to receive due to the elimination of regional through-and-out rates. Having found the proposed subzonal allocations to be unjust and unreasonable, the Initial Decision recommends instead using a combined zone or two separate zones, one for PJM and one for Midwest ISO.

23. The March 10 Partial Decision, April 13 Partial Decision, and Initial Decision rule on a number of proposed adjustments to the test-period data for known and measurable differences. The Presiding Judge finds that the SECA should be adjusted to remove revenues for contracts that were shown to have terminated prior to, or during, the transition period. The Presiding Judge also orders that the SECA be adjusted to reflect

[35] Classic PJM includes transmission owners that joined PJM on or before April 1, 2002, including: Allegheny, Allegheny Power, BG&E, FirstEnergy, PECO, Pepco, PPL, PSEG, Rockland, and UGI.

[36] New PJM includes transmission owners that joined PJM after April 1, 2002, including: AEP, ComEd, Dayton, Dominion, and Duquesne.

reductions in load served by certain entities during the transition period compared to the test period.

24. The Initial Decision finds that the Commission provided guidance that the SECA should be based on actual billing units, which is a type of usage charge. In the compliance filings, Midwest ISO TOs and the PJM transmission owners change the SECA mechanism from a usage charge to a fixed charge. Under a usage charge, the SECA would be assessed on actual monthly billing units. With the proposed fixed charges, the SECA would be a fixed demand-type charge, which is not based on current usage. The Initial Decision finds that the proposed fixed charges are not in compliance with the Commission's orders and that the SECA rates should be developed in the traditional manner – by dividing test-year revenues by test-year load – and applied to actual monthly billing determinants for the transition period.

25. The Initial Decision rejects FirstEnergy Service's contention that existing transaction charges should be capped at the amount of a customer's SECA obligation, finding that the Commission has not held that such a cap should be employed. The Initial Decision states that "[i]t is clear that the Commission only intended this mechanism to apply to [load-serving entities] with [existing transactions] which would pay [regional through-and-out] rates and SECA charges. The adjustment proposed would be to the SECAs and not to the [regional through-and-out] rates for [existing transactions]."[37]

26. The Initial Decision finds that Six Michigan Cities' bundled power supply contracts with CCG successfully demonstrate that CCG had taken responsibility under the fixed-price contracts to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, CCG should pay a portion of Six Michigan Cities' SECA. In addressing CCG's "ripple" claim against AEM, the Initial Decision finds that CCG successfully demonstrates that under its fixed price bundled supply contract with AEM, which CCG used to supply Six Michigan Cities, AEM had taken responsibility to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, AEM should pay a portion of the SECA that Six Michigan Cities shifts to CCG. The Initial Decision also finds that Quest demonstrates that, under its fixed price bundled power supply contract with MAEM, MAEM had taken responsibility under the contract to arrange and pay for the through-and-out service necessary to supply the customer and that, therefore, MAEM should pay a portion of Quest's SECA.

27. Finally, the Presiding Judge finds that Green Mountain is appropriately assessed SECA charges under an unexecuted service agreement, which the Commission accepted in Docket No. ER05-1423-000, subject to the outcome of the hearing on the compliance

[37] Initial Decision, 116 FERC ¶ 63,030 at P 263.

filings. Green Mountain argues that it should not be assessed a SECA under the Midwest ISO tariff because it is not a transmission customer or market participant under the tariff. The Presiding Judge finds that Schedule 22 of the Midwest ISO tariff, which provides for the recovery of the PJM transmission owners' lost revenues from entities within Midwest ISO, specifically provides for the collection of SECA charges from customers that may not be transmission customers or market participants as those terms are defined under the tariff. The Presiding Judge finds that the record shows that Green Mountain is an entity that serves load in Midwest ISO using transmission service under the Midwest ISO tariff that it has arranged through an affiliate, BP Energy Company (BP Energy).

2. Commission Determination

28. As we explain below, while it is true that the Commission required lost revenue calculations to reflect known and measurable changes, as well as hubbing adjustments, we disagree with the Initial Decision as to the burden of proof. Specifically, the burden of proof concerning the lost revenue amounts is a shifting one: the onus is first on the transmission owners to provide and support their claimed lost revenue amount with information in their possession; once they have met that burden, the onus shifts to the transmission customers to provide and support adjustments to that data. We will, therefore, overturn the Initial Decision's rejection of the transmission owners' claimed lost revenues for failure to make adjustments for known and measurable changes and hubbing adjustments. We will also reverse the Initial Decision's finding that claimed lost revenue amounts are invalid because witnesses failed to independently verify every data point used in determining the lost revenues and because certain transmission owners failed to sponsor witnesses that individually supported the transmission owners' level of lost revenues, as administrative proceedings do not impose such requirements. We find that each calculation and input to the lost revenue amounts is supported with detailed testimony and exhibits that provide substantial evidence for the purpose of establishing just and reasonable SECA charges, and the fact that a transmission owner's lost revenue amounts incorporate calculations and data from several witnesses – even if the witnesses were presented on behalf of another company – does not indicate that the final calculation does not enjoy ultimate support.

29. We find that the appropriate test-year periods for the first and second years of the transition period are calendar-years 2002 and 2003, respectively, as required in the Commission's orders adopting the SECA mechanism. Using two test periods smoothes out any irregularities to the extent that either year contains data abnormalities, and the Commission does not require that the test period be of equal length to the period of effectiveness of the rates being tested.

30. We find that the utilization of average rates when determining the SECA is consistent with the Commission's previous directives and is a practical means to determine the level of lost revenues that is just and reasonable. We will affirm the Initial

Decision's rejection of in-out transactions in the average rates of certain PJM transmission owners, finding that the SECA is not the appropriate vehicle for PJM transmission owners to recover lost revenues associated with the elimination of regional through-and-out rates for in-out transactions because PJM voluntarily eliminated rate pancaking for such transactions and was not directed to do so by the Commission in this proceeding. However, we will reverse the Initial Decision and accept the inclusion of out-in transactions, finding it to be just and reasonable because such revenues can reasonably be expected to be lost due to the elimination of rate pancaking for transactions that sink within the region. We will also affirm the Initial Decision's adoption of the proposed hubbing adjustments for generation-only control areas and address other proposed hubbing adjustments raised on exception.

31. We will reverse the Initial Decision's finding limiting the SECA to inter-RTO lost revenue recovery. The Commission's prior orders provided for the recovery of certain intra-RTO lost revenues through the SECA, and the intra-RTO lost revenues included in the proposed SECA charges are compliant with these requirements.

32. We find that the Initial Decision incorrectly finds that affiliate transactions should be excluded from the SECA calculations. The revenue that a transmission owner receives from an affiliate for through-and-out transmission service is recorded as revenue for the transmission owner, just as if that revenue came from an unaffiliated entity, and is used to reduce the transmission costs to be born through the license plate rates from the transmission owner's local load. Thus, the inclusion of these revenues is necessary to prevent immediate cost shifting with the replacement of rate pancaking with license plate rates and to keep the transmission owners revenue neutral.

33. We will affirm the proposed subzonal SECA charges, subject to specific adjustments directed herein and, accordingly, reverse the Initial Decision on this issue. The Commission determined that the SECA should be charged on a subzonal basis. The Initial Decision asserts that subzonal allocations should be rejected because benefits to a subzone are not considered in creating the subzones. We disagree. Using tag data to trace specific transactions during the test period, subject to adjustments for known and measurable differences, and using that information to create subzones does consider the benefits that accrue to loads in a subzone due to the elimination of regional through-and-out rates. We also disagree with the finding in the Initial Decision that using subzones produces unjust and preferential results between the Classic PJM and New PJM regions. Having subzones in the New PJM region but not in the Classic PJM region does not result in cost shifts between the two regions. The Commission previously found, and we continue to find here based on the record, that parties should use North American Electric Reliability Corporation tag data to calculate SECA charges to create subzones in Midwest ISO and New PJM notwithstanding the fact that such tag data cannot be used to create subzones in Classic PJM. We also find that the proposal to allocate the SECA to load within the Classic PJM region on a load-ratio share basis is just and reasonable. While

not as precise as using tag data to create zones or subzones, the SECA charges are still calculated based on transactions during the test period that can be traced to the Classic PJM area. We find that no methodology would perfectly align those that benefit due to the elimination of regional through-and-out rates, and using North American Electric Reliability Corporation tag data where possible and a load-ratio share where such tag data would not work is a reasonable compromise and one that is reasonably consistent with cost-causation principles.

34. We will reverse, in part, the findings in the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision with regard to the finding that contracts terminating prior to the transition period are not SECA eligible. However, we will affirm the findings in the Initial Decision with respect to certain discrete claims that test-period load is not reflective of load served during the transition period, and thus, SECA obligations should be adjusted accordingly. As we explain, load-serving entities are assigned a SECA obligation based on test-period imports that utilized through-and-out service, unless such entities can demonstrate known and measurable changes have occurred such that they do not benefit due to the elimination of rate pancaking. We find that the fact that an entity's test-period contracts expired prior to the transition period and were not replaced with new contracts that cross the boundaries that were previously subject to rate pancaking is not dispositive as to whether the entity benefits due to the elimination of rate pancaking. Rather, as the Commission previously found, the elimination of rate pancaking will result in more remote generation becoming economic for import, which will put downward pressure on market prices where the importing load is located, resulting in lower costs for purchases from local generation as well as imports.

35. However, we will affirm the findings in the Initial Decision, though under different reasoning, that certain parties' SECA obligations should be adjusted to reflect reductions in load served between the test period and the transition period. Unlike load-serving entities claiming that contracts terminated prior to the transition period and are, thus, not SECA eligible, adjustments to SECA obligations are appropriate for load-serving entities with reduced load during the transition period to accurately align the benefits realized due to the elimination of regional through-and-out rates to the level of load served during the transition period. Where the load served by the load-serving entity during the transition period has been reduced since the test period, or is no longer served by the load-serving entity during the transition period, it is reasonable to conclude that the load-serving entity will not benefit due to the elimination of regional through-and-out rates for the load no longer served.

36. We will reverse the Initial Decision's rejection of the fixed subzonal SECA charges proposed in the compliance filings. While the Initial Decision is correct that the SECA adopted by the Commission was designed as a usage charge, the transmission owners in each RTO have voluntarily designed their subzonal SECA charges as fixed charges that recover test-period revenues and do not vary with the level of the load-

serving entity's load. The Initial Decision appropriately finds that such fixed charges result in unjust and unreasonable charges for certain entities that have experienced reductions in the loads that they serve since the test period. However, rather than order changes to all of the non-settled SECA charges to reflect a traditional usage charge, which would generally result in increased charges for customers, we will order adjustments to the subzonal SECA charges for these entities to reflect their load reductions.

37. We will affirm the Initial Decision's finding that FirstEnergy's SECA obligation should not serve as a cap for through-and-out charges associated with existing transactions (i.e., reservations for requests for service made prior to November 17, 2003, for service commencing before April 1, 2004). We agree that FirstEnergy is not entitled to a refund for the amount that FirstEnergy's through-and-out charges for existing transactions exceed its SECA obligations under the Commission's prior orders, nor is such a refund necessary to ensure that transmission owners do not double recover their revenue requirements.

38. We will affirm the Initial Decision's findings that Six Michigan Cities successfully demonstrate that CCG should pay a portion of Six Michigan Cities' SECA. However, we will reverse the Initial Decision as to the exact portion of one entity's SECA obligation that should be shifted to CCG. We will reverse the Initial Decision as to CCG's "ripple" claim against AEM because our prior orders did not provide for "ripple" claims. We will also reverse the Initial Decision's finding that a contract existed between Quest and MAEM and that, therefore, MAEM should pay a portion of Quest's SECA.

39. Finally, we will reverse the Presiding Judge's finding that Green Mountain is appropriately assessed SECA charges under an unexecuted service agreement even though Green Mountain is not a transmission customer or market participant under the Midwest ISO tariff. Instead, we find that BP Energy, Green Mountain's affiliate that directly contracted with Midwest ISO on Green Mountain's behalf during the transition period, should pay Green Mountain's SECA obligation.

40. In addition, we address three settlements that were certified to the Commission as contested during the hearing. We find that two of the settlements are no longer contested and that the objections to the third settlement are outside of the scope of the settlement and are being addressed in the order on rehearing being issued concurrently with this order. We also address a fourth settlement that was filed on October 29, 2009, and find that it is no longer contested.

B. Sponsorship/Support for Level of Lost Revenues

41. The Initial Decision finds that the transmission owners failed to adequately support the claimed lost through-and–out revenues that provide the basis for calculating

the SECA. The findings and arguments on exceptions are discussed below with respect to each party.

1. Midwest ISO TOs

a. Initial Decision

42. The Initial Decision finds several flaws in the testimony proffered by Midwest ISO TOs' witness, Mr. Heintz. The Initial Decision finds that Mr. Heintz failed to consider known and measurable changes in developing the lost through-and-out revenues from historical data, failed to independently verify the through-and-out revenue amounts provided by the transmission owners and Midwest ISO and, by failing to independently verify the data, erroneously relied on hearsay in calculating the level of regional through-and-out rates from which the level of lost revenues for Midwest ISO TOs was derived. The Initial Decision also notes Mr. Heintz' statement that "it is almost impossible to calculate the transmission charges paid to other transmission owners because of the increased number of transactions."[38] The Initial Decision concludes that the level of through-and-out revenues, and thus, the level of lost revenues for Midwest ISO TOs, is unacceptable.[39]

b. Brief on Exceptions

43. Midwest ISO TOs take exception to the Initial Decision's findings on this issue. Midwest ISO TOs state that they submitted hundreds of pages of testimony, exhibits, and workpapers of Mr. Heintz providing the narrative descriptions, calculations, and North American Electric Reliability Corporation tag data used in both the development of Midwest ISO TOs' lost revenues and the allocation of those lost revenues to be collected from the PJM entities. Midwest ISO TOs assert that Mr. Heintz properly analyzed the data to calculate Midwest ISO TOs' lost revenues and, through sworn testimony, supports both the calculations and resulting amount of lost revenues, as well as the allocation of the lost revenues to be recovered from the PJM entities.

44. Midwest ISO TOs further argue that the Initial Decision erroneously faults them for failing to account for known and measurable changes of which they were not and could not have been aware at the time they calculated their lost revenues and made their compliance filing. Stating their willingness to adjust test-period data for known and measurable changes, Midwest ISO TOs nevertheless assert, contrary to the Initial Decision, that prior Commission orders placed the burden on the party seeking such

---

[38] *Id.* P 115 (*citing* Heintz Test., Ex. No. MTO-1 at 23:21-22).

[39] *Id.* P 115-16.

changes to propose and prove them.[40] Indeed, Midwest ISO TOs assert that a specific purpose of the hearing was to allow parties who seek adjustments for known and measurable changes to prove the validity of those adjustments. Midwest ISO TOs state that the Commission previously allowed filing parties to submit rates based upon test-period data, subject to subsequent adjustments for known and measurable changes proven by another party.[41]

45. Positing that the Federal Rules of Evidence and the hearsay rule do not apply to Commission proceedings, Midwest ISO TOs further object to the Initial Decision's application of the hearsay rule.[42] They argue that, taken to the extreme, the Initial Decision would require a company to sponsor a witness for each exhibit or analysis directly performed by that employee and potentially additional witnesses for any data underlying the exhibit or analysis.

46. Midwest ISO TOs further assert that the Initial Decision quotes out of context Mr. Heintz' statement that it is "almost impossible" to calculate transmission charges paid to other transmission owners. They argue that, read in context, Mr. Heintz was describing his reason for choosing a particular method for developing lost revenues; the statement does not bear upon whether Mr. Heintz independently verified the through-and-out revenues of the transmission owners.

---

[40] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 24 (*citing* February 2005 Order, 110 FERC ¶ 61,107 at P 38 ("the reasonableness of the proposed adjustments to the SECA rates contained in the various pleadings cannot be summarily decided based on the existing record and should be addressed at hearing.")).

[41] *Id.* at 23 (*citing Duke Power Co.*, Opinion No. 641, 48 FPC 1384 (1972) (accepting rates as filed by also accepting intervenors' and Staff's rationale supporting certain adjustments to test-year cost of service); *Market-Based Rate for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Notice of Proposed Rulemaking, FERC Stats. & Regs., Proposed Regs. 2004-2007 ¶ 32,602, at P 64 (2006) (contemplating that intervenors propose known and measurable changes to be considered in the delivered price test analysis)).

[42] *Id.* at 33 (*citing* section 308(b) of the FPA, 16 U.S.C. § 825(b) ("[a]ll hearings, investigations and proceedings under this Act shall be governed by rules of practice and procedure to be adopted by the Commission, and in the conduct thereof the technical rules of evidence need not be applied."); *Mont. Power Co. v. FPC*, 185 F.2d 491, 498 (D.C. Cir. 1950) (*Montana Power*) (hearsay rule not applicable to administrative proceedings so long as evidence upon which an order is ultimately based is both substantial and has probative value)).

c. Briefs Opposing Exceptions

47. Constellation asserts that SECA proponents, such as Midwest ISO TOs, can point to no Commission order that eliminated their burden to identify necessary changes to the historical data used to calculate their claimed lost revenues. Constellation claims that the July 2003 Order placed the onus on the transmission owners to make adjustments for known and measurable differences,[43] and no subsequent occurrence in the proceeding has relieved them of that burden.

48. Allegheny and Southern Maryland oppose Midwest ISO TOs' arguments, to the extent that the arguments are intended or are interpreted to require the imposition of any SECA charges on Allegheny or Southern Maryland.[44]

2. AEP, ComEd, and PECO

a. Initial Decision

49. The Initial Decision finds that, while Exelon's witness, Mr. Bustard, adequately supported ComEd's through-and-out revenue claims, his testimony did not adequately address known and measurable adjustments to the through-and-out revenues to develop lost revenues. The Initial Decision finds that ComEd's lost revenues are not in compliance with Commission orders and, therefore, rejects them.[45]

50. The Initial Decision finds that PECO's witness, Mr. Dessender, adequately provided the raw data supporting through-and-out revenues for PECO but "did not, however, support the level of lost revenues or SECA revenues."[46] The Initial Decision notes Dr. Henderson's statement that he was not sponsoring PECO's lost revenues and further finds that Mr. Bustard's testimony does not support PECO's lost revenue claims.

---

[43] Constellation Brief Opposing Exceptions to the Initial Decision at 12-13 (*citing* July 2003 Order, 104 FERC ¶ 61,105 at P 54 (SECA compliance filings required to "use [North American Electric Reliability Corporation] tag data and develop lost [through-and-out] revenues for the most recent twelve months, with adjustments for known and measurable differences, to most closely reflect future trading patterns")).

[44] Allegheny and Southern Maryland Brief Opposing Exceptions to the Initial Decision at 5.

[45] Initial Decision, 116 FERC ¶ 63,030 at P 117.

[46] *Id.* P 119 (*citing* Dessender Test., Ex. No. EXE-10).

Concluding that no witness supported PECO's lost revenue claims, the Initial Decision rejects them.[47]

51. The Initial Decision finds that AEP's witness, Mr. Bethel, supported AEP's historical revenues based on the through-and-out revenues for calendar-years 2002 and 2003, which were used as inputs to Dr. Henderson's SECA analysis. The Initial Decision further finds, however, that some of AEP's proposed lost revenues would have to be "recomputed to conform to the findings of [the] Initial Decision."[48]

b. Briefs on Exceptions

52. AEP, Dayton, and Exelon dispute the Initial Decision's findings concerning AEP's, ComEd's, and PECO's support for their level of lost revenues. They argue that ComEd, PECO, and AEP supported their lost revenue claims consistent with the Commission's directives. They state that AEP and ComEd directly calculated their lost through-and-out revenues for 2002 and 2003 based on actual billing determinants and rates charged for point-to-point transmission service through and out of their respective systems to points of delivery in the combined region. They state that Mr. Bethel and Mr. Bustard reviewed internal billing data and Open Access Same-Time Information System reservation data to verify their test-period through-and-out revenues. They state that, in addition to removing grandfathered transactions, both Mr. Bethel and Mr. Bustard removed transactions with a point of delivery outside of the combined region, thereby ensuring that no transactions to which a PJM regional through-and-out rate could be assessed during the transition period were included in AEP's and ComEd's lost revenue amounts.

53. Furthermore, AEP, Dayton, and Exelon dispute the Initial Decision's rejection of the transmission owners' lost revenue amounts for failure to account for known and measurable changes. For largely the same reasons cited by Midwest ISO TOs, they assert that the burden of coming forward with information to support a known and measurable adjustment to an entity's SECA obligation necessarily must rest with the entity proposing the adjustment and possessing information, if any, to justify the adjustment as a known and measurable change. They state that, where a party did present information to verify an adjustment (e.g., Duke and Allegheny), adjustments were made.[49]

[47] *Id.*

[48] *Id.* P 120.

[49] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 14.

54. With particular regard to the Initial Decision's finding that AEP's lost revenues require recomputation, AEP, Dayton, and Exelon state that Mr. Bethel in fact made two adjustments to AEP's 2002 lost through-and-out revenues. First, they state that he added revenues that are associated with transactions that first exited AEP at interfaces outside of the combined region and then re-entered to sink within the region. Second, they state that he removed revenues associated with transactions representing intra-AEP transfers. For AEP's 2003 lost revenues, AEP, Dayton, and Exelon contend that Mr. Bethel only needed to make the second adjustment because the integration of Dominion into PJM largely negated the need to include revenues associated with transactions that first left the combined region and then re-entered to sink within the region.

55. AEP, Dayton, and Exelon further argue that the Initial Decision errs in finding that no witness supported PECO's claimed lost revenues. They state that PECO's lost revenue claim was supported by Mr. Bustard and Dr. Henderson, with reliance upon the test-period through-and-out revenue calculations presented by Mr. Dessender.[50] AEP, Dayton, and Exelon state that, since PECO was a transmission-owning member of PJM and not a transmission provider during the test periods, PECO relied upon the testimony of Mr. Dessender to verify the revenues received by PJM for through-and-out transmission service provided in 2002 and 2003. AEP, Dayton, and Exelon state that, as a PJM employee, Mr. Dessender was not expected to support lost revenues for PECO, but he did provide the through-and-out revenue data necessary to develop PECO's claim. They also state that the lost revenue claim itself is supported by Mr. Bustard and Dr. Henderson, as Mr. Bustard recommends how the revenues presented in Mr. Dessender's testimony should be treated in the determination of PJM lost revenues, and Dr. Henderson performs the actual calculation of PJM lost revenues on behalf of PECO.

56. Green Mountain argues that the Initial Decision's failure to reject AEP's lost revenue calculations is erroneous and inconsistent with the Initial Decision's treatment of the lost revenues of other transmission owners. For example, Green Mountain states that both ComEd's and AEP's lost revenue calculations failed to account for known and measurable adjustments, but the Initial Decision rejects the former and accepts the latter.

57. Additionally, Green Mountain and Quest, Strategic, and WPS Energy state that the Initial Decision errs in determining that the transmission owners, having failed to support their lost revenue claims, should be permitted to make additional compliance filings to cure the failures. Green Mountain argues that, rather than allowing yet another round of

[50] *Id.* at 27 (*citing* Dessender Test., Ex. No. EXE-10).

compliance filings, the Commission should simply reject the filings based on the transmission owners' failure to meet their burden of proof.[51]

c. **Briefs Opposing Exceptions**

58. For the same reasons cited above with regard to Midwest ISO TOs, Constellation argues that the onus is on the transmission owners to adjust their historical data for known and measurable changes.[52] In any case, Quest, Strategic, and WPS Energy argue that they identified in testimony two adjustments that warrant known and measurable treatment but that were not taken into account.[53] To that end, Quest, Strategic, and WPS Energy dispute any assertion that only known and measurable changes existing during the 2002 and 2003 test periods should be considered.

59. AEP, Dayton, and Exelon, as well as Midwest ISO TOs, urge the rejection of any argument that transmission owners should not be allowed to revise their lost revenue claims and compliance filings. Indeed, AEP, Dayton, and Exelon assert that, since the lost through-and-out revenues of PJM transmission owners are recovered under the Midwest ISO tariff (and vice versa), the transmission owners in one RTO must be directed (rather than denied the opportunity) to file revisions to their respective tariff necessary to comply with the Commission's findings concerning the lost revenues claims of transmission owners in the other RTO.[54]

60. Midwest ISO TOs contend that an outright rejection of the compliance filings without an opportunity to revise them would be tantamount to a denial of rate recovery

---

[51] Green Mountain Brief on Exceptions to the Initial Decision at 46 (*citing Northern States Power Co.*, 64 FERC ¶ 61,324 (1993), *order on reh'g*, 74 FERC ¶ 61,106, at 61,344 (1996) ("Northern States' evidentiary presentation in support of its proposed rates was so flawed that we could not find the proposed rates in this particular proceeding to be just and reasonable.")).

[52] Constellation Brief Opposing Exceptions to the Initial Decision at 13-14.

[53] Quest, Strategic, and WPS Energy Brief Opposing Exceptions to the Initial Decision at 56-57. In support of the two changes, they state that Quest and WPS Energy provided service to Northern Ohio Aggregation Coalition (NOAC) during the test period but did not serve that load during the transition period, and Quest and WPS Energy provided service to North Star Steel (North Star) in 2002 and 2003 but ceased doing so in April 2004.

[54] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 21.

and, therefore, would violate section 206 of the FPA (requiring that the Commission establish a just and reasonable replacement rate)[55] as well as the United States Constitution. Midwest ISO TOs argue that Commission rejection of SECA charges without further compliance filings would also be inequitable for transmission owners that sought in good faith to comply with Commission orders.[56]

3. Classic PJM TOs

a. Initial Decision

61. The Initial Decision also rejects Classic PJM TOs' claimed lost revenues, stating:

> Mr. Dessender, a witness for [Classic PJM TOs], testified that he quantified the actual [through-and-out] revenues that all [Classic PJM TOs] received during [calendar-years] 2002 and 2003 using PJM's actual billing records…Mr. Dessender excluded [through-and-out] revenues for transactions to the [New York Independent System Operator, Inc. (NYISO)]…In addition, he excluded revenues for grandfathered service…This information was then provided to Dr. Henderson for use in determining the lost revenues for all of PJM. On cross-examination, Dr. Henderson testified [that] he was not sponsoring the lost revenues for [Classic PJM TOs], but rather Mr. Bustard was…However, Mr. Bustard explained that "PJM actually did the calculation" of [through-and–out] revenues that should be used in calculating the lost revenue…Therefore, it is found that [Classic PJM TOs'] lost revenues are rejected.[57]

62. The Initial Decision further finds that, as with other parties, Classic PJM TOs failed to support known and measurable changes to the through-and-out revenues to develop lost revenues.[58]

---

[55] Midwest ISO TOs Brief Opposing Exceptions to the Initial Decision at 2-3 (*citing* 16 U.S.C. § 824e(a)).

[56] *Id*. at 3.

[57] Initial Decision, 116 FERC ¶ 63,030 at P 118 (*citing* Dessender Responses, Ex. No. CTO-1 at 2-6; Tr. 1108:6-1109:5 (Henderson); Tr. 1382:18-23 (Bustard)).

[58] *Id.*

b. **Brief on Exceptions**

63. Classic PJM TOs dispute the Initial Decision's findings on this issue. Stating that the Initial Decision intimates that the witness' positions are contradictory as to who sponsored the lost revenues, Classic PJM TOs contend that the there is no such conflict. They argue that, while the Initial Decision implies that Mr. Bustard testified that Mr. Dessender was the "sponsor" of Classic PJM TOs' lost revenues, the record shows that Mr. Bustard clearly understood that Classic PJM TOs' lost revenue claim was based on the testimony of Mr. Dessender. Classic PJM TOs further assert that Mr. Dessender's statement, in turn, that he was not sponsoring the claim of any Classic PJM TO for lost revenues to be recovered through SECA charges only addressed the fact that PJM, as the independent RTO, was not taking a position – rightfully so – in the proceeding regarding what any particular Classic PJM TO was entitled to recover.

64. Classic PJM TOs assert that PJM is the only entity in possession of the test-period data necessary to compute Classic PJM TOs' test-period regional through-and-out rates, and therefore, it was necessary for Classic PJM TOs to rely on PJM, through Mr. Dessender, to supply the lost through-and-out revenue data. Classic PJM TOs contend that nothing in the testimony of Mr. Bustard, Dr. Henderson, or Mr. Dessender calls into question the accuracy of Mr. Dessender's data or the reliability of Dr. Henderson's calculations regarding the amount of revenues to be recovered in SECA charges for Classic PJM TOs.

65. Classic PJM TOs further argue that the Initial Decision's rejection of their lost revenue claim on the basis that it fails to reflect known and measurable changes is based on "nothing more than a general objection to the Presiding Judge's determination that 'known and measurable changes' were not adequately considered by the transmission owners."[59] Classic PJM TOs contend that the Initial Decision fails to identify any specific known and measurable change that should have been taken into account.

c. **Briefs Opposing Exceptions**

66. AMP-Ohio contends that the Initial Decision's rejection of the lost revenue claims of Classic PJM TOs should be upheld. AMP-Ohio claims that BG&E and FirstEnergy, specifically, each failed to support any level of lost revenues. AMP-Ohio argues that Classic PJM TOs inappropriately seek to equate lost revenues and through-and-out revenues, without support for the amount or accuracy of their lost revenue claims. AMP-Ohio adds that lost revenues and through-and-out revenues are not to be confused with SECA revenues, which consist of revenues collected during the transition period, and that the Initial Decision carefully distinguishes lost revenues from through-and-out revenues.

[59] Classic PJM TOs Brief on Exceptions to the Initial Decision at 12.

AMP-Ohio states that the starting point for calculating lost revenues is regional through-and-out rates during the 2002 and 2003 test periods but that, once the through-and-out revenues are determined, there are further adjustments to be made, including for grandfathered transactions, known and measurable changes, and any other necessary adjustment to assure that the historic through-and-out revenues would truly be eliminated during the transition period by the Commission's orders for serving load in the combined region.

67. AMP-Ohio claims that FirstEnergy does not and cannot state that Dr. Henderson analyzed, adjusted, verified, or did anything other than simply to accept as lost revenues the total through-and-out revenues provided to him by Mr. Dessender, the PJM employee charged with deriving the through-and-out revenues for each Classic PJM TO. AMP-Ohio also states that FirstEnergy does not and cannot state that any Classic PJM TOs analyzed or verified the data provided by Mr. Dessender. Moreover, AMP-Ohio asserts that FirstEnergy's Brief on Exceptions to the Initial Decision makes clear that no immediate steps were taken to convert through-and-out revenues into lost revenues. Additionally, AMP-Ohio contests FirstEnergy's statement that Mr. Dessender provided the lost revenues of Classic PJM TOs. AMP-Ohio argues that Mr. Dessender did not undertake that task at all, and in fact, testified that he did not.

68. AMP-Ohio further claims that BG&E, like FirstEnergy and other Classic PJM TOs, simply assumed that through-and-out revenues were in fact lost revenues. AMP-Ohio states that, even if the claimed through-and-out revenue calculations were accurate – a position that AMP-Ohio disputes – there is no reason to assume that those calculations produced an accurate estimate of lost revenues.

69. AMP-Ohio argues that, in any case, the validity of the average rates used as a measure of the compensation due to Classic PJM TOs has been in dispute. Moreover, AMP-Ohio claims that, contrary to Classic PJM TOs' contention, Mr. Dessender did not disclaim responsibility for calculating SECA charges. Rather, AMP-Ohio asserts that he disclaimed responsibility for having calculated lost revenues during cross-examination.

70. AMP-Ohio contends that the result of the foregoing errors is lost revenue data – and equivalent SECA charges – that have been overstated by $13,000,000, with no witness supporting the numbers or responding to questions designed to confirm the need for further adjustment. AMP-Ohio states that, in short, Classic PJM TOs failed to meet their burden of proof.

71. Green Mountain also argues that the Initial Decision correctly finds that Classic PJM TOs failed to support their lost revenue claims. Green Mountain claims that Classic PJM TOs treat the Commission's statement that the SECA should be calculated "*based on* the revenue recovered through the just and reasonable rate charged in an historical

period for [through-and-out] service"[60] as though it required that SECA revenues equal the historical revenues collected pursuant to regional through-and-out rates. Green Mountain contends, however, that "based on" does not mean "equal to." Green Mountain argues that the Commission made clear that the overriding goal of the SECA was to approximate the expected use of the exporting utility's transmission system during the two-year transition period. Thus, it was incumbent upon the SECA claimants, based upon test-period through-and-out revenues as a starting point, to determine what each company's through-and-out revenues would have been from December 2004 through March 2006, had the Commission not ordered the elimination of regional through-and-out rates.

72. Green Mountain claims, however, that Classic PJM TOs never took the further step of adjusting the test-period through-and-out revenues to account for known and measurable changes to reflect what they would have earned during the transition period, had regional through-and-out rates still been in effect. For example, Green Mountain states that Classic PJM TOs failed to account for the many factors that would have changed the level of through-and-out revenues from the test period to the transition period, including changes in load, retirements and outages of existing generating units, the construction of new units, the entry and exit of various market participants, and the implementation of the Midwest ISO day-ahead and real-time energy markets. Instead, as the Initial Decision notes, the transmission owners simply presumed that, except for the elimination of regional through-and-out rates, trading patterns and transactions during the 2004-2006 transition period would exactly match those experienced during the 2002 and 2003 test periods.

73. Similar to Green Mountain's arguments, Four TDUs assert that, while Mr. Dessender provided testimony demonstrating the historical level of Classic PJM TOs' through-and-out revenues, no witness testified in support of Classic PJM TOs' lost revenues. Four TDUs argue that nothing in Classic PJM TOs' Brief on Exceptions to the Initial Decision provides the element identified by the Initial Decision as missing (i.e., credible testimony that, if pancaked rates had remained in place, transition-period payments thereunder would have resembled test-period payments thereunder).[61]

74. AEP, Dayton, and Exelon do not oppose Classic PJM TOs' arguments but assert that, given their own reliance on Dr. Henderson's analysis, Classic PJM TOs should be

[60] Green Mountain Brief Opposing Exceptions to the Initial Decision at 7 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 48 (emphasis added by Green Mountain)).

[61] Four TDUs Brief Opposing Exceptions to the Initial Decision at 10.

estopped, individually or together, from challenging Dr. Henderson's SECA analysis of other transmission owners' lost revenues.[62]

4. Dayton

a. Initial Decision

75. With regard to Dayton's lost revenues, the Initial Decision states the following:

> Ms. Crawford's exhibits [(Dayton's witness)] show how she computed Dayton's [through-and–out] revenues for [calendar-years] 2002 and 2003. However, Ms. Crawford did not support Dayton's lost revenues. Indeed, she stated that the 2002 and 2003 [through-and–out] revenues related to transactions within the [c]ombined [r]egion and are used as the revenue neutral target amount to be recovered by load throughout the [c]ombined [region]…It is therefore found that Dayton's lost revenues are not supported by the record.[63]

b. Brief on Exceptions

76. Dayton argues that the Initial Decision fails to set forth any facts or policy reasons supporting the finding that Dayton did not support its lost revenues. Dayton states that, while the Initial Decision finds that Dayton established the amount of through-and-out revenues that it had received in 2002 and 2003, in the next sentence, without explanation or factual reference, the Initial Decision concludes that Dayton did not support its lost revenues. Asserting that its supported and undisputed 2002 and 2003 through-and-out revenues are the same as its lost revenues, Dayton contends that the Initial Decision's conflicting findings make no sense. In fact, Dayton argues that the Initial Decision's reference to Dayton's lost revenue calculation being "revenue neutral" is not only a *non-sequitur*, but the citation provided – Ex. No. DPL-3 at 4 – does not exist. In any case, Dayton maintains that revenue neutrality was a fundamental tenet of the SECA rate methodology adopted by the Commission,[64] and no party opposed Dayton's lost revenue calculation.

---

[62] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 8.

[63] Initial Decision, 116 FERC ¶ 63,030 at P 122 (*citing* Dayton 2003 Through-and-Out Revenues, Ex. No. DPL-3 at 4). *See also* Crawford Test., Ex. No. DPL-1 at 4.

[64] Dayton Brief on Exceptions to the Initial Decision at 14-15 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 46).

77. Moreover, Dayton argues that the Initial Decision finds that other transmission owners, such as Exelon and AEP, which employed the same methodology as Dayton, had supported their lost revenues. Dayton claims that, like those other transmission owners' witnesses, Ms. Crawford calculated Dayton's lost revenue claims based on the actual billing determinants and the actual, Commission-approved rates from Dayton's Open Access Same-Time Information System. Dayton adds that Ms. Crawford ensured that the results matched Dayton's actual revenues by reviewing internal billing data and Open Access Same-Time Information System reservation data.

78. Dayton asserts that the Initial Decision's rejection of Dayton's lost revenues is especially egregious given the Commission's instruction that "it is not necessary to require the filing of updated cost-of-service studies. We have previously accepted the existing rates of these companies as just and reasonable and our actions in this proceeding will maintain the revenues produced by those rates during the two-year transition period."[65] Dayton states that it identified and supported its lost revenues for the relevant years, no participant objected, and the Initial Decision errs in rejecting them.

c. **Briefs Opposing Exceptions**

79. Constellation asserts that Dayton is among the transmission owners that bear the burden of making adjustments to historical data for known and measurable changes and reflecting those changes in claimed lost revenue amounts.[66]

80. Quest, Strategic, and WPS Energy's arguments opposing the Brief on Exceptions to the Initial Decision submitted by AEP, Dayton, and Exelon are summarized above.

5. **Dominion**

a. **Initial Decision**

81. With regard to Dominion, the Initial Decision states the following:

> Dominion's [through-and–out] revenues for transmission service within the [c]ombined [r]egion for 2003 were $19,201,075.55. This amount was stipulated to in the Joint Stipulation of Facts…These revenues were provided to Dr. Henderson for computation of the SECA. Dominion did

---

[65] *Id.* at 16-17 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 49).

[66] Constellation Brief Opposing Exceptions to the Initial Decision at 14.

not support its lost revenues and therefore, its proposed lost revenues are rejected.[67]

b. Brief on Exceptions

82. Dominion states that the Initial Decision errs by concluding that Dominion did not support its lost revenue claim and by failing to acknowledge record evidence, including sworn testimony, supporting its lost revenue claim.

83. Dominion states that its lost revenues were calculated based on actual billing determinants and Commission-approved rates from Dominion's Open Access Same-Time Information System. Dominion states that it reviewed reservation data and internal accounting records and excluded grandfathered transactions; only revenues under Dominion's tariff were included. Dominion states that the 2003 through-and-out revenue calculations reflect transmission revenues received during the test period by Dominion for the use of its system to deliver power through or out of Dominion under Schedules 7 and 8 of its tariff.

6. Duquesne

a. Initial Decision

84. The Initial Decision finds that Duquesne's witness, Mr. Thompson, satisfactorily determined the level of through-and-out revenues for Duquesne but failed to satisfactorily adjust those historical revenues to reflect known and measurable changes to develop lost revenues. Accordingly, the Initial Decision rejects them.[68]

b. Brief on Exceptions

85. Duquesne asserts that its lost revenues were not adjusted for known and measurable changes because there were no such changes affecting its lost revenue calculations. Duquesne notes that no party has identified any adjustment that it believes should be made to Duquesne's calculations in order to reflect known and measurable changes.

---

[67] Initial Decision, 116 FERC ¶ 63,030 at P 123 (*citing* Joint Stipulation of Facts, Ex. No. S-3 at 5).

[68] *Id.* P 124.

c. **Brief Opposing Exceptions**

86. To the extent that any arguments against allowing additional compliance filings might apply to Duquesne, Duquesne asserts that it should be permitted further opportunity to support its level of lost revenues and, more specifically, its claim that its level of lost revenues requires no adjustment for known and measurable changes.

7. **All Transmission Owners**

a. **Initial Decision**

87. The Initial Decision finds that the SECA applicants did not comply with the Commission's directive that the SECA applicants remove hubbing transactions. For instance, Midwest ISO TOs did not propose any hubbing adjustments, and the Presiding Judge holds that Midwest ISO TOs' willingness to accept hubbing adjustments made by other parties is a passive approach that does not constitute sufficient compliance. The Presiding Judge notes that Mr. Heintz asserted that hubbing adjustments need to be shown and would require a thorough analysis to determine the amount of imports ultimately exported out of PJM, yet he admitted that he did not conduct such a review and made no hubbing adjustments.[69] The Presiding Judge also maintains that it was inadequate for Mr. Heintz to passively claim that he would incorporate the hubbing adjustments once they have been proven.[70] The Presiding Judge finds that, by failing to take proactive steps to remove hubbing transactions from their SECA calculations, the applicants' proposed SECA charges are unjust and unreasonable, necessitating the rejection of their filings. In this regard, the Presiding Judge finds that transactions that sink outside of the combined region continue to be subject to regional through-and-out rates, and thus, there is no lost revenue for the applicants to recoup via the SECA.[71]

b. **Briefs on Exceptions**

88. Midwest ISO TOs and AEP, Dayton, and Exelon oppose the Initial Decision's rejection of the compliance filings for failing to include all possible hubbing adjustments. They contend that the information necessary to verify certain adjustments was unavailable to transmission owners at the time of their compliance filings, and thus, the burden of supporting further hubbing adjustments must rest with the entity proposing the

[69] *Id.* P 342, 344 (*citing* Heintz Cross-Answering Test., Ex. No. MTO-99 at 9:21-10:1, Tr. 905:17-23 (Heintz)).

[70] *Id.* P 342 (*citing* Heintz Answering Test., Ex. No. MTO-94 at 22:2-3).

[71] *Id.* P 343.

adjustment and possessing information, if any, to justify the adjustment. Requiring any parties engaging in hubbing transactions to identify the adjustments is reasonable, according to Midwest ISO TOs, because hubbing involves purchases of power that sink in an area different from the sink indicated by North American Electric Reliability Corporation tag data, and thus, Midwest ISO TOs would not have data indicating that there was hubbing involved. Midwest ISO TOs and AEP, Dayton, and Exelon also maintain that the Commission intended for parties with specific hubbing transactions to come forward with them,[72] specifically noting that the procedural schedule issued on July 20, 2005, established that hubbing adjustments were to be filed as part of the answering testimony and exhibits.[73] While they did not propose any hubbing adjustments, Midwest ISO TOs support Dr. Henderson's analysis of Duke's hubbing adjustment, and they state that they will reflect any other hubbing adjustments that are approved by the Commission.[74] Similarly, AEP, Dayton, and Exelon maintain that, where a party presented information to verify an adjustment (e.g., Duke and Allegheny's generation-only control area hubbing adjustments), the corresponding adjustments were made. In addition, Midwest ISO TOs argue that the Initial Decision errs in relying heavily on BG&E's broad contentions, and if BG&E had specific hubbing adjustments to propose, it should have notified Midwest ISO TOs.[75] AEP, Dayton, and Exelon add that the Initial Decision errs in finding that the compliance filings are fatally flawed because Midwest ISO TOs did not develop a hubbing adjustment on behalf of BG&E. They conclude that the Initial Decision's rejection of the compliance filings due to non-

---

[72] *See* Midwest ISO TOs Brief on Exceptions to the Initial Decision at 28-29 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 80, 96; *Minn. Power & Light Co*., 11 FERC ¶ 61,312, at 61,645 n.45 (1980) ("[g]enerally, the party seeking to call the prudence of an expenditure into question must do so by adducing evidence or citing to material of which the Commission may take official notice")).

[73] Midwest ISO TOs also contend that the Presiding Judge does not consider that the Commission reinstituted the SECA methodology in its November 2004 Order, which was issued on November 18, 2004, and required the parties to submit compliance filings one week later, by November 24, 2004. Midwest ISO TOs claim that it is unreasonable to expect that they could have incorporated all hubbing adjustments in one week.

[74] Midwest ISO TOs note that they have agreed to make adjustments for parties that identified specific hubbing adjustments to Midwest ISO TOs' data, such as Duke.

[75] Midwest ISO TOs claim that, in contrast to other parties, BG&E never identified for Midwest ISO TOs any specific hubbing adjustments that should have been made, despite its numerous opportunities to do so through stakeholder meetings, pleadings, and testimony.

compliance is arbitrary and capricious, inconsistent with the Commission's orders, and unsupported by substantial evidence.

c. Briefs Opposing Exceptions

89. BG&E and Constellation state that, by failing to fully remove hubbing transactions, Midwest ISO TOs and AEP, Dayton, and Exelon failed to meet their burden of proof, and therefore, rejection of their compliance filings is warranted. Constellation maintains that Midwest ISO TOs and AEP, Dayton, and Exelon did not attempt to argue that hubbing did not occur and instead attempted to shift the burden of identifying hubbing transactions to other parties.[76] According to Constellation, however, the requirement to comply with the Commission's directives falls squarely upon the parties submitting the compliance filings and cannot be shifted.

90. BG&E maintains that the Commission directed the applicants to include the hubbing adjustments as a condition to its approval of the SECA as just and reasonable and did not state that the SECA filers were to omit hubbing adjustments for the Commission to fill in later. BG&E contends that the failure of Midwest ISO TOs and AEP, Dayton, and Exelon to comply cannot be excused based on those parties' disagreement with the Commission's directive. BG&E states that AEP, Dayton, and Exelon cannot pick-and-choose which aspects of the Commission's requirements that they will comply with. As for Midwest ISO TOs, BG&E argues that Mr. Heintz effectively concedes that he has not made the necessary hubbing adjustments and instead points to unnamed others to recalculate the SECA charges for him. In response to Midwest ISO TOs' claim that they had only one week to prepare their compliance filings, BG&E submits that the Presiding Judge cannot be faulted for rejecting the hastily-prepared filings. BG&E concludes that hubbing adjustments are an integral feature of a properly-constructed SECA and requests that the Commission affirm the rejection of these compliance filings.

8. Commission Determination

91. The Initial Decision's rejection of all of the claimed lost revenue amounts is based, generally, on at least one of three findings: (1) a subject transmission owner's failure to make adjustments for hubbing transactions and for known and measurable changes to the through-and-out revenues used to calculate lost revenues invalidates the lost revenue amount; (2) data not independently verified by the witness supporting a transmission owner's lost revenue calculation constitutes inadmissible hearsay, and its inclusion in a

---

[76] Constellation contends that Mr. Heintz admitted that he "had none" when asked about hubbing adjustments. Constellation Brief Opposing Exceptions to the Initial Decision at 28 (*citing* Tr. 905:15-17 (Heintz)).

lost revenue calculation invalidates the entire lost revenue amount; and (3) where no particular witness sponsors a subject transmission owner's final lost revenue calculation, the claimed lost revenue amount is invalid. We address each of these findings in order.

92. A determination as to whether the transmission owners should have, but failed to, make adjustments for hubbing transactions and for known and measurable changes to their lost revenue claims begins with a discussion of the burden of proof in this case. The Initial Decision's findings on this point are based largely on the presumption that the transmission owners bear the entire burden of proof; that is, the transmission owners must not only calculate historical through-and-out revenues but must also identify and make any necessary adjustments, including for hubbing transactions and known and measurable changes, to the base-period data.

93. While it is true that the Commission required lost revenue calculations to reflect known and measurable changes (as well as hubbing adjustments), we disagree with the Initial Decision's finding that the transmission owners alone bear the burden of proof. While sections 205 and 206 of the FPA,[77] as well as the Administrative Procedure Act,[78] place the burden on the moving party, a responding party has a burden of its own; a responding party must provide more than unsubstantiated claims.[79] Thus, as relevant here, the burden of proof concerning the lost revenue amounts at issue is a shifting burden: the onus is first on the transmission owners to provide and support their claimed lost revenue amounts with information in their possession; once they have met that burden, the onus shifts to the transmission customers to provide and support the adjustments that they advocate. This is consistent with the fact that transmission owners possess historical base-period data, while transmission customers are likely to possess information necessary to make adjustments based on data that transmission owners are not likely to possess. This determination is also consistent with prior Commission orders in this case that discussed the role of transmission customers in developing SECA rates.[80]

---

[77] 16 U.S.C. §§ 824d(e), 824e(b) (2006).

[78] 5 U.S.C. § 556(d) (2006).

[79] *E.g.*, *Georgia Power Co.*, 52 FERC ¶ 61,321 at 62,278 & n.5 (1990); *PJM Interconnection, LLC*, 115 FERC ¶ 61,052 at P 11 n.10 (2006).

[80] *See, e.g.*, November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 96 (customers with hubbing transactions "will have the opportunity to show in the implementation stage that transactions tagged as sinking in their zones actually sink in another zone or RTO"); February 2005 Order, 110 FERC ¶ 61,107 at P 38 (reasonableness of customers' proposed adjustments to SECA rates should be addressed at hearing).

Thus, where a transmission owner properly demonstrates a claimed lost revenue amount, the amount should be considered uncontroverted unless a transmission customer, in turn, properly demonstrates a required adjustment. Accordingly, the Initial Decision errs to the extent that it places the burden of showing known and measurable changes squarely on the transmission owners. We will, therefore, overturn the Initial Decision's rejection of the transmission owners' claimed lost revenues for failure to make adjustments for hubbing transactions and for known and measurable changes. Below, we order specific adjustments to the claimed lost revenue amounts and SECA charges for hubbing transactions and known and measurable changes that have been properly supported.

94. We agree, in part, with the Initial Decision's finding that AEP's level of lost revenues requires recomputation in accordance with other aspects of the Initial Decision. Below, we order specific adjustments to the claimed lost revenue amounts of AEP and other transmission owners based on the extensive record established in this proceeding. As noted above, any additional adjustments to the level of lost revenues beyond those discussed below must be proposed and proven by the transmission customers, a burden that was not satisfied here.

95. Consistent with our various directives in this order that transmission owners adjust their claimed lost revenue amounts, we reject arguments that the transmission owners should not be allowed to make further compliance filings in this case. Having adopted the SECA for the relevant transition period, the next objective in this proceeding is to determine the appropriate SECA charges; the Commission cannot simply reject the compliance filings and end the case. Moreover, we believe that the transmission owners have sought in good faith to comply with the numerous and complex prior Commission orders relevant to determining SECA liability; therefore, we will grant them further opportunity to revise their compliance filings.

96. We next turn to the Initial Decision's application of the hearsay rule.[81] The Federal Rules of Evidence's hearsay rule, as applied in a hearing in a Federal district court, generally speaking prohibits the admission of a statement, other than one made by the declarant while testifying at the trial or hearing, offered in evidence to prove the truth of the matter asserted therein.[82] The Initial Decision rejects certain calculations provided by Mr. Heintz, based upon the Initial Decision's finding that he relied upon hearsay (i.e., through-and-out revenue amounts provided to him by Midwest ISO and Midwest ISO

---

[81] Initial Decision, 116 FERC ¶ 63,030 at P 114-16.

[82] Fed. R. Evid. 801(c). There are, of course, exceptions allowing the use of hearsay in a hearing in a Federal district court. In the context of a hearing before the Commission, however, because the hearsay rule is as a general matter irrelevant, the exceptions are likewise as a general matter irrelevant.

TOs, without independently verifying the amounts himself).[83] We find that this rejection was made in error and, moreover, is inconsistent with the Initial Decision's acceptance of data provided by other transmission owners.

97. We need not and thus do not decide here whether Mr. Heintz relied on what would be inadmissible hearsay had this proceeding been tried in Federal district court,[84] or whether an exception to the hearsay rule would apply. That is because administrative proceedings, such as Commission proceedings, are not bound by the Federal Rules of Evidence. Section 308(b) of the FPA, in fact, specifically provides that the "technical rules of evidence need not be applied" in hearings under the FPA.[85] Rather, the evidence upon which an order is ultimately based must be substantial and have probative value.[86] The requirement that administrative findings accord with substantial evidence does not forbid administrative utilization of probative hearsay in making such findings.[87] Under Rule 509(a) of the Commission's Rules of Practice and Procedure, the basic test as to the admissibility of evidence is whether the evidence is of the "kind that would affect reasonable and fair minded persons in the conduct of their daily affairs."[88]

98. We find that Mr. Heintz provided substantial evidence having probative value and of the kind that would affect reasonable and fair minded persons in the conduct of their daily affairs. Indeed, the Initial Decision lauds Mr. Heintz for providing "detailed testimony and exhibits" and showing a thorough knowledge of the case and the proposed

[83] Initial Decision, 116 FERC ¶ 63,030 at P 114-16.

[84] In any event, we note that our discovery rules provide that all discovery responses must identify the preparer (or the person under whose direct supervision the response was prepared) and either be under oath or be accompanied by a signed certification that the response is "true and accurate to the best of that person's knowledge, information, and belief formed after a reasonable inquiry." 18 C.F.R. § 385.403(c) (2009); *accord* 18 C.F.R. § 385.408 (2009) (providing for a participant to serve on another participant a request for admission of "the genuineness of any document or the truth of any matter of fact", and the genuineness and truth are "deemed admitted" absent objection within 20 days).

[85] 16 U.S.C. § 825g(b) (2006).

[86] *See, e.g.*, *Montana Power*, 185 F.2d at 498; *Johnson v. United States*, 62 F.3d 187, 190 (D.C. Cir. 1980).

[87] *Id.*

[88] 18 C.F.R. § 385.509(a) (2009).

SECA methodology, even under cross-examination.[89] While he might not have independently verified every data point used in determining Midwest ISO TOs' lost revenues, administrative proceedings do not impose such a requirement. Therefore, we will reverse the Initial Decision's rejection of his calculations based upon the hearsay rule.

99. We further note our agreement with Midwest ISO TOs that the Initial Decision takes out of context Mr. Heintz' statement that it is "almost impossible" to calculate directly the transmission charges paid to other transmission owners. Read in context, Mr. Heintz was merely noting the complexity of making such a calculation as a reason supporting the particular SECA methodology he used (use of an average rate to allocate lost revenues), which we address below.

100. We now address the Initial Decision's findings that no witnesses sponsored Classic PJM TOs', PECO's, and Dayton's lost revenue claims. The Commission's review of the record reveals that, for each of these companies, a witness supported each element of the final, claimed lost revenue amounts. We agree with Classic PJM TOs that the fact that a calculation incorporates data from several witnesses – even if the witnesses were presented on behalf of another company – does not indicate that the final calculation enjoys no ultimate support. The critical question is whether the underlying data is relevant and its accuracy is supported. As to Classic PJM TOs, nothing in the testimony of one witness contraindicates the relevancy and accuracy of data from another witness. As both Classic PJM TOs and PECO note, they properly relied upon Mr. Dessender, Manager, Markets Settlement for PJM, to verify the revenues received by PJM for through-and-out transmission service provided in 2002 and 2003. As a PJM employee, he was not expected to support lost revenues for the individual transmission owners; Mr. Bustard and Dr. Henderson collectively provided such support for Classic PJM TOs and PECO. As to Dayton, it is not clear why the Initial Decision concludes that no witness supported Dayton's lost revenue claim. The Initial Decision says little on this point. In any case, based upon our review of the record, we find that Ms. Crawford adequately supported Dayton's lost revenue calculation and agree with Dayton that there is no apparent reason in the Initial Decision to find otherwise. Accordingly, we will reverse the Initial Decision's findings that the lost revenue claims of Classic PJM TOs, PECO, and Dayton should be rejected because no witnesses sponsored such lost revenue claims.

101. Similarly, with particular regard to Dominion, there is little in the Initial Decision that supports rejecting Dominion's claimed lost revenues. Our review of the record reveals no persuasive reason to discredit Dominion's calculations. Accordingly, we will

[89] Initial Decision, 116 FERC ¶ 63,030 at P 114.

overturn the Initial Decision's rejection of Dominion's claim for failure to support its lost revenues.

C. <u>Test Period</u>

1. <u>Initial Decision</u>

102. The Initial Decision recognizes that, during peak summer months, energy usage and transmission volumes are relatively high, whereas during off-peak months, load is much lower, and load-serving entities recognize this fact in contracting for energy and transmission services.[90] Since regional through-and-out rates were not eliminated until December 2004 (eight months into the first year of the two-year transition period established in the November 2003 Rehearing Order), the Initial Decision finds that transmission owners recovered their peak-period revenues during the summer of 2004.[91] Consequently, the Initial Decision finds that by using the entire 2002 calendar year as a test year for SECA charges in effect from December 1, 2004, through March 31, 2005, transmission owners would over recover SECA revenues, since through-and-out revenues for the summer of 2004 were not lost.

103. Because of the seasonal nature of energy throughput, the Initial Decision finds that the record supports reducing the length of the test period for SECA charges in effect from December 1, 2004, through March 31, 2005, to correspond to the reduction in the length of the first year of the two-year transition period.[92] In addition, the Initial Decision finds that using 2003 historical data, adjusted for known and measurable changes, is the just and reasonable test period for the entire transition period for several reasons:

> [f]irst, it reflects the most recent time frame for which data would have been available when the first compliance filings were made. Second, it does not require the use of non-contiguous months (i.e., January through March and December) for the 2002 historical period. Third, it recognizes that the [North American Electric Reliability Corporation] e-Tag Version 1.6, which was used until April 10, 2002, did not require specific sinks to be listed, thereby requiring alternative methods for identifying sinks for the beginning of 2002…Fourth, the four months in 2002 are not a good proxy

---

[90] The Initial Decision refers to Mr. Norton's statement that AMP-Ohio arranged summer-only schedules to meet the summer peak needs of its members. *Id.* P 40 (*citing* Norton Answering Test., Ex. No. AMP-1 at 29).

[91] *Id.*

[92] *Id.* P 42.

> for trading patterns in January through March 2005 since many of the changes had not yet taken place. Fifth, as discussed below, the revenues for 2002 are inexplicably much higher than the revenues for 2003, thus 2003 provides a better proxy for revenue purposes. Finally, [calendar-year] 2003 provides for administrative convenience. Although data for the four months of 2003, as adjusted, should be readily available, given the fact that 2002 only represents 25 percent of the historical period, it would be administratively prudent to use the more recent data.[93]

104. In the alternative, the Initial Decision recommends that, if the Commission disagrees and requires the use of 2002 throughput data, the 2002 test-year data should be reduced to reflect the same months as are reflected in the transition period – January through March, and December.[94]

2. <u>Briefs on Exceptions</u>

105. Midwest ISO TOs and AEP, Dayton, and Exelon disagree with the Initial Decision and assert that calendar-year 2002 should be included as a test year in developing the SECA.[95] They further disagree that, if utilized, 2002 data should be limited to a few months, arguing that Commission precedent does not require that the length of the test period equal the length of the period for which the rate is in effect.[96] Furthermore, AEP, Dayton, and Exelon contend that, in establishing the SECA, and when revising the start date until December 1, 2004, the Commission required that the SECA be based on calendar-years 2002 and 2003.[97]

106. However, Constellation asserts that the Commission should adopt the alternative recommendation and only utilize the corresponding four months from 2002. Constellation asserts that, since regional through-and-out rates were not eliminated until December 1, 2004, limiting the 2002 test year to the corresponding months (i.e., January through March and December) will reflect the seasonal variation in trading patterns and

---

[93] *Id.* P 43 (*citing* Russell Answering Test., Ex. No. ORM-2 at 51 n.49).

[94] *Id.* P 42.

[95] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 17; AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 63-68.

[96] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 20.

[97] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 63 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66; November 2004 Order, 109 FERC ¶ 61,168 at P 61).

prevent the over collection of lost revenues by the transmission owners. Constellation argues that the transmission owners should have adjusted their SECA calculations to reflect the corresponding four months of 2002 as the test period when the Commission shortened the first part of the transition period to four months.[98]

107. AEP, Dayton, and Exelon argue that, contrary to the Initial Decision, the 2003 data was not the most recent data *available* because 2003 data had not been reviewed in order to make it available for use as test-year data. They assert that in 2004 the parties were preparing an alternative transmission pricing proposal and that only 2002 data had been reviewed so as to be available for use as test-year data.[99] Constellation asserts that the Initial Decision fails to explain how the 2003 data is more administratively convenient. AEP, Dayton, and Exelon and Midwest ISO TOs argue that, contrary to the Initial Decision, at the time of the compliance filings the use of the 2002 data was also administratively convenient.

108. AEP, Dayton, and Exelon take exception to the Initial Decision's finding that 2002 was not a good test year because this issue was not set for hearing. They assert that the Commission clearly stated that data from calendar-years 2002 and 2003 were to be utilized for test-year data.

109. AEP, Dayton, and Exelon also take exception to the Initial Decision's finding that PJM's lost revenue for 2002 was inexplicably higher than it was for 2003. They assert that Dr. Henderson's supplemental direct testimony provided a sufficient explanation of the differences, and they note that the lost revenue for many transmission owners, including AEP and Dayton, and the total lost revenue of all transmission owners in the combined region, was higher in 2003 than in 2002.[100] Midwest ISO TOs aver that the fact that 2002 revenues were higher than 2003 revenues does not make one of the test periods unjust and unreasonable. Constellation asserts that this difference in the 2002 and 2003 data supports using both years' data for the test period to avoid the anomalies that could arise if only a single test year is used. Midwest ISO TOs argue that using two test periods smoothes out any irregularities, to the extent that either year contains data abnormalities.[101]

---

[98] Constellation Brief on Exceptions to the Initial Decision at 17-18.

[99] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 65.

[100] *Id.* at 67 (*citing* Henderson Supplemental Test., Ex. No. PTO-105 at 3:15-5:13).

[101] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 18-19.

110. Midwest ISO TOs and AEP, Dayton, and Exelon assert that changes to the North American Electric Reliability Corporation tag data software do not render the 2002 data unjust and unreasonable, contrary to the Initial Decision's finding, especially since several additional steps were taken to identify the sinks for certain tags, resulting in sound and reliable data.[102] Furthermore, Constellation argues that the Initial Decision fails to recognize that tag data were also not available for the Classic PJM region in 2003.[103]

111. Midwest ISO TOs contend that the Commission previously denied arguments that 2002 data is not indicative of future trading patterns because Midwest ISO had not yet begun operations.[104] Constellation contends that the Presiding Judge's finding that the use of the four months in 2002 does not accurately reflect future trading patterns because certain changes had not taken place yet (i.e., the start of the Midwest ISO markets) is unpersuasive because there were many changes in future trading patterns after 2003, including the integration of ComEd and AEP into PJM and the start of the Midwest ISO day-ahead and real-time energy markets in April of 2005.

3. Briefs Opposing Exceptions

112. Constellation, AMP-Ohio, and Quest, Strategic, and WPS Energy contend that the Initial Decision's alternative recommendation to use the four corresponding months in 2002 is a reasonable means to prevent over recovery of lost revenues while complying with the Commission's directives. Constellation and Quest, Strategic, and WPS Energy argue that the exclusive use of 2003 data for both transition periods would allow the transmission owners to collect regional through-and-out rates based on peak summer months.

113. Constellation asserts that, despite their opposition to limiting the use of 2002 data to the corresponding months, AEP, Dayton, and Exelon admit that such an approach is reasonable.[105] Furthermore, Constellation asserts that Dr. Henderson testified that revising the SECA calculation to include only the corresponding four months of 2002

---

[102] *See, e.g.*, *id.* at 19.

[103] Constellation Brief on Exceptions to the Initial Decision at 20.

[104] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 18-19.

[105] Constellation Brief Opposing Exceptions to the Initial Decision at 27 (*citing* AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 68).

data "would be a straightforward matter"[106] and "may be a better indicator of the pattern of imports, and therefore the pattern of benefits, during the particular four months a[t] issue."[107]

114. Ormet supports the Initial Decision, asserting that utilizing only 2003 data as the test period would be consistent with Commission policy, would avoid major anomalies from 2002, and would meet equitable concerns. Furthermore, since the 2003 data was already compiled and used in this proceeding, applying this 2003 data to the four months of the first transition period (i.e., December 2004 through March 2005) would take minimal effort.[108]

4. Commission Determination

115. We agree with Midwest ISO TOs and AEP, Dayton, and Exelon that the appropriate test year periods for the first and second years of the transition period are calendar-years 2002 and 2003, respectively. In the November 2003 Rehearing Order, the Commission balanced the interest of using the most recent data with the interest of using data that made filings that could be placed into effect for the first year of the transition period feasible. Therefore, the Commission "require[d] that the SECA be based on a [calendar-year] 2002 test year period in the first year of the transition period and a [calendar-year] 2003 test year for the second year of the transition period."[109] While the date for filing SECA compliance filings was subsequently delayed until November 24, 2004, by the Going Forward Principles, that settlement did not extend the transition period or change the test-period requirements of the November 2003 Rehearing Order. We agree with the transmission owners that the use of 2002 data for the first year of the transition period remained necessary for administrative convenience when the filings were due on November 24, 2004, given that the transmission owners and other parties were engaged in intensive negotiations to develop alternative long-term pricing solutions for filing by October 1, 2004. While the North American Electric Reliability Corporation tag data for the period prior to April 10, 2002, did not list specific sinks for certain schedules, the transmission owners took additional steps to identify sinks for those tags. In addition, as Midwest ISO TOs and Constellation argue, using two test periods

[106] *Id*. (*citing* Henderson Rebuttal Test., Ex. No. PTO-81 at 43:22-44:1; Initial Decision, 116 FERC ¶ 63,030 at P 41).

[107] *Id.* (*citing* Henderson Rebuttal Test., Ex. No. PTO-81 at 43:17-19; Initial Decision, 116 FERC ¶ 63,030 at P 41).

[108] Ormet Brief Opposing Exceptions to the Initial Decision at 59-65.

[109] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66.

smoothes out any irregularities to the extent that either year contains data abnormalities, whereas the alternative proposal to use 2003 data for the entire transition period could fail to adjust for such abnormalities. Further, the Commission does not require that the test period be of equal length to the period of effectiveness of the rates being tested.[110]

D. Method for Determining Level of Lost Revenues

1. Initial Decision

116. Mr. Heintz calculated lost revenues for the Midwest ISO transmission owners and the corresponding lost revenue obligations of the PJM entities by using the "total" method of determining an average rate. To generate an average rate using the total method, Mr. Heintz determined a Midwest ISO transmission owner's total amount of through-and-out revenues received and divided it by the corresponding total amount of through-and-out MWhs, regardless of whether the ultimate sink of the transactions were outside of the combined region.[111] In contrast, Dr. Henderson calculated lost revenues for AEP, Dayton, and Exelon and the corresponding lost revenue obligations of the Midwest ISO load zones by using the "footprint" method of determining an average rate. To generate an average rate using the footprint method, Dr. Henderson divided a PJM transmission owner's lost revenues due to the elimination of regional through-and-out rates (including revenues for in-out transactions, which cross the Midwest ISO-PJM seam and then exit to sink outside of the combined region) by the total through-and-out MWhs that sank within the Midwest ISO-PJM footprint. The determination of average rates by Mr. Heintz and Dr. Henderson using the total and footprint methods, respectively, is discussed in more precise detail below.

117. Mr. Heintz calculated an average rate via the total method in six steps. First, he determined the total through-and-out revenues received by each Midwest ISO transmission owner during both rate periods using historical data.[112] Second, OATi, the

[110] 18 C.F.R. § 35.13(d) (2009).

[111] As discussed below, Mr. Heintz removed transactions that exited the Combined Region via the Midwest ISO-Ontario Hydro interface.

[112] During periods when they were not in Midwest ISO, transmission owners used actual billing determinants and rates from FERC Form No. 1 or Open Access Same-Time Information System data to determine their lost revenues. During periods when they were in Midwest ISO, Mr. Heintz used data from Midwest ISO Revenue Distribution Reports to determine lost revenues derived from through-and-out service under the Midwest ISO tariff. In addition, Midwest ISO transmission owners that were also Mid-

(continued…)

entity that keeps North American Electric Reliability Corporation tag data, produced reports summarizing the total MWhs of energy each Midwest ISO transmission owner transmitted that sank in each zone within the combined region.[113] Third, he adjusted the tag data used in step two to remove duplicate tags, eliminate MWhs associated with grandfathered agreements, and substitute subzonal data, where available. Fourth, he found the average rate for through-and-out transactions for each Midwest ISO transmission owner by dividing their total lost revenues found in step one by the adjusted total MWhs that they transmitted found in step three. He adjusted this average rate calculation to remove the lost revenues and MWhs from transactions that exited the Midwest ISO-Ontario Hydro interface and did not return. However, Mr. Heintz did not remove the lost revenues and MWhs from other transactions that exited the combined region, stating that he was unable to ensure that such transactions did not subsequently re-enter the region.[114] Fifth, he determined the lost revenue obligations of each PJM entity by multiplying the average rate for each Midwest ISO transmission owner found in step four by the MWhs transmitted by each respective Midwest ISO transmission owner that sank within the PJM entity's zone found in step three. Finally, in step six, each Midwest ISO transmission owner reviewed the data for the months during the test period that they were not in Midwest ISO to ensure accuracy.

118. To allow Dr. Henderson to develop average rates in PJM using the footprint method, each transmission owner first provided Dr. Henderson with estimates of their lost revenues due to the elimination of regional through-and-out rates.[115] These estimates included all revenues associated with in-out transactions that ultimately sank outside of the combined region. Dr. Henderson explained that the financial effects of eliminating regional through-and-out rates are different for Midwest ISO and PJM transmission owners because, while Midwest ISO reserves transmission service to a sink, PJM reserves transmission service to a point of delivery, which may or may not be the same as

---

Continent Area Power Pool members included lost revenues associated with the loss of Schedule F revenues under the Mid-Continent Area Power Pool regional tariff. Heintz Test., Ex. No. MTO-1 at 18:8-20:15.

[113] The tag data was adjusted to correct spelling errors, utilize a uniform naming convention, split certain control areas into separate transmission zones, remove MWhs that were not for through-and-out transactions, and ensure that loads were reflected in the proper transmission zone. *Id.* at 20:16-21:14.

[114] *Id.* at 26:4-20.

[115] Dr. Henderson stated that Allegheny provided insufficient data to allow him to apply the footprint method, and consequently, he used the total method to determine an average rate for Allegheny. Henderson Test., Ex. No. PTO-1, 23:2-13.

the ultimate sink where the associated energy is consumed.[116] Dr. Henderson argued that the inclusion of revenues associated with in-out transactions was necessary to hold the transmission owners revenue neutral, as required by the Commission, and that the Commission has not determined that the portion of lost revenues that would otherwise be allocated to load outside of the combined region is unrecoverable in this proceeding.[117] To calculate the average rate for each transmission owner, Dr. Henderson then divided each transmission owner's lost revenues by the MWhs of energy transmitted by each PJM transmission owner that sank within the combined region, which was estimated using North American Electric Reliability Corporation tag data.[118] Finally, Dr. Henderson determined the lost revenue obligations of each Midwest ISO and PJM load zone by multiplying the average rate for each PJM transmission owner by the MWhs transmitted by each respective PJM transmission owner that sank within the load's zone.

119. The Initial Decision finds that, while an average rate method can be a legitimate way to allocate revenue responsibility, the use of an average rate in this proceeding yields "absurd results."[119] The Presiding Judge finds that by utilizing average rates the proposed SECA charges aggravate cost shifting among transmission owners.[120]

---

[116] For example, Dr. Henderson explained that, for an in-out transaction from PJM to AEP and then to a sink outside of the combined region, the point of delivery would reflect the first leg of the journey from PJM to AEP, rather than the ultimate sink outside of the combined region. Dr. Henderson explained that two through-and-out charges would have been assessed, one to PJM and a second to AEP. Due to the elimination of regional through-and-out rates, Dr. Henderson contends that the through-and-out charge on the first leg of the transaction would be lost, and a through-and-out charge would be assessed only on the second leg of the transaction. Henderson Rebuttal Test., Ex. No. PTO-81 at 4:20-6:17.

[117] *Id.* at 3:1-11.

[118] Revenues and MWhs associated with grandfathered agreements were removed from the average rate calculation.

[119] Initial Decision, 116 FERC ¶ 63,030 at P 223.

[120] For this reason, the Presiding Judge finds that the zonal and subzonal allocation under the SECA methodology should be abandoned, and instead the lost revenues should be allocated through a single uniform charge across the entire Midwest ISO-PJM footprint. We discuss the findings concerning zonal and subzonal allocations in a subsequent section of the order.

120. In regard to the footprint method for designing an average rate, the Presiding Judge finds that it is "especially egregious, as it assesses costs to parties who could not possibly be responsible for costs associated with the elimination of [regional through-and-out] rates."[121] The Initial Decision finds that revenues from in-out transactions are not a legitimate component of lost revenues, as the Commission stated that lost revenues are to be recovered "for transactions to serve load *within the other RTO*."[122] The Presiding Judge cites Quest's example of an in-out transaction in which energy was transmitted from one PJM transmission owner to a second PJM transmission owner but then exited PJM to sink in a location outside of the combined region. The Presiding Judge states that the load-serving entity outside of the combined region would benefit from the transaction, but the cost would be shifted to load-serving entities within the combined region. The Presiding Judge explains that this outcome is inconsistent with the principle of cost causation because parties may not be responsible for costs that they could not have caused.[123] The Presiding Judge also states that "the SECA is designed to recover all of the revenues lost due to the elimination of [regional through-and-out] rates" and notes that only the rates between PJM and Midwest ISO were to be eliminated.[124] Therefore, the Initial Decision finds that the Commission did not require the elimination of regional through-and-out rates for transactions that sink outside of the combined region nor the recovery of the costs from any associated lost revenues. The Initial Decision concludes that the inclusion of these transactions violates previous Commission orders and finds that in-out transactions should be eliminated from the lost revenue calculations.[125]

121. In addition, the Initial Decision rejects the adjustment submitted by Mr. Bethel to account for out-in revenues, which would increase SECA charges paid to AEP by including revenues associated with transactions that exited the combined region but then re-entered to sink within the region. The Presiding Judge finds that "these uncorroborated adjustments result in over-recovery and are unjust and unreasonable and contrary to the Commission's intention in imposing the SECA."[126] The Initial Decision

[121] Initial Decision, 116 FERC ¶ 63,030 at P 231.

[122] *Id.* P 126 (*citing* November 2004 Order, 109 FERC ¶ 61,168 at P 66 (emphasis added by Presiding Judge)).

[123] *Id.* P 231 (*citing KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300-01 (D.C. Cir. 1992)).

[124] *Id.* P 127 (*citing* November 2004 Order, 109 FERC ¶ 61,168 at P 61).

[125] *Id.*

[126] *Id.* P 343.

accepts the hubbing adjustment for Duke and Allegheny's generation-only control areas, which reflects that, if transactions that sink in generation-only control areas are not used for station power, there must be a second, corresponding transaction to deliver the power to a different sink. The Presiding Judge finds the adjustment to be correct and compliant with the Commission's previous orders.[127]

122. Finally, the Initial Decision finds that the parties have not independently verified the accuracy of the North American Electric Reliability Corporation tag data. The Presiding Judge concedes that some type of cross checking of the data took place because the parties have identified transactions that were incorrectly included.[128] However, the Presiding Judge finds that it would be a "monumental verification task" for the Commission or the parties to confirm the accuracy of the aggregate numbers upon which the SECA calculations are based because, while the underlying data can be obtained, following the steps that led up to the conclusions "would require literally tracking piece by piece each transaction that occurred in all of the affected areas for the entire test period."[129] The Presiding Judge states that some North American Electric Reliability Corporation tags are incomplete, erroneous, duplicative, or missing, specifically noting that there is no indication whether a given sink was actually a mid-way point to a further delivery control area.[130]

2. <u>Briefs on Exceptions</u>

123. Contrary to the Initial Decision, Midwest ISO TOs contend that the average rate method is consistent with Commission precedent, including previous orders directing compliance in this proceeding,[131] and other situations where direct assignment is not possible or would require an inordinate amount of effort to calculate.[132] They maintain that, while the Initial Decision discusses why it rejected the footprint method for designing an average rate, it does not provide concrete reasons for rejecting the average rate by Midwest ISO TOs. Midwest ISO TOs argue that calculating lost revenues by considering an entity's load factor (i.e., the amount of reserved transmission capacity that

---

[127] *Id.* P 345.

[128] *Id.* P 301.

[129] *Id.* P 300.

[130] *Id.* P 298 (*citing* Bourquin Test., Ex. No. CTO-4 at 10:15-16).

[131] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 37 (*citing*, *e.g.*, November 2003 Rehearing Order, 105 FERC ¶ 61,212 at 43-44, 67).

[132] *Id.* at 38 (*citing* Heintz Test., Ex. No. MTO-1 at 25:3-5).

is actually utilized by a given load) is akin to using actual invoices, which was already rejected by the Commission.[133] Even if Midwest ISO TOs redesign their SECA obligations based on a single combined region zone, as recommended by the Presiding Judge, Midwest ISO TOs claim that they would still need to use an average rate to determine the lost revenues to be allocated to the load-serving entities in the zone. They ask that the Commission affirm that the average rate methodology is acceptable and that Midwest ISO TOs' average rate is just and reasonable. If the Commission instead rejects the use of average rates, Midwest ISO TOs request that the Commission clarify how the transmission owners are to perform these calculations without utilizing average rates or actual revenues.

124. AEP, Dayton, and Exelon maintain that the Initial Decision errs in rejecting the use of an average rate to develop SECA charges. They contend that applying an average rate is a necessary step in converting from a transaction-based rate design to a load-based one, stating that an average rate is the only practical method to recover transmission revenues derived from a capacity-based reservation system.[134]

125. AEP, Dayton, and Exelon assert that the Initial Decision's rejection of the footprint method is indistinguishable from its findings concerning in-out transactions and concerns that there is a mismatch between the numerator and denominator of the footprint method. They argue that there is substantial evidence supporting the reasonableness of the footprint method. They maintain that the average rate employed by Midwest ISO TOs gives an imprecise estimate based primarily on total revenues, total MWh, and a simultaneous allocation based on MWhs sinking in the combined region. AEP, Dayton, and Exelon claim that, in contrast, their lost revenues were independently verified via sworn testimony and did not include revenues associated with transactions with a point of delivery outside of the combined region, thereby ensuring that no transactions for which PJM regional through-and-out rates could be assessed would be included.[135]

126. AEP, Dayton, and Exelon urge the Commission to find that the revenues for in-out transactions are legitimate lost revenues. If, however, the Commission finds that in-out transactions should be excluded, AEP, Dayton, and Exelon request that the Commission require the removal of in-out transactions from the numerator of the footprint average

[133] *Id.* at 39 (*citing* Heintz Rebuttal Test., Ex. No. MTO-103 at 10:6-12:9; November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 67).

[134] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 56-57 (*citing* Henderson Test., Ex. No. PTO-1 at 15:15-23).

[135] *Id.* at 58-59.

rate method, thereby avoiding any mismatch between the numerator and denominator of the rate.[136] They emphasize that, rather than serving as an indictment of the footprint method, the Initial Decision's primary concern is whether in-out transactions should be included in the development of the SECA charges.

127. AEP, Dayton, and Exelon argue that the Initial Decision errs in characterizing in-out transactions as originating in only certain territories. They respond that, according to Dr. Henderson, all PJM transmission owners experience lost revenues associated with in-out transactions, and he quantified those amounts for each PJM transmission owner.[137] AEP, Dayton, and Exelon explain, while that the Midwest ISO transmission owners do not experience lost through-and-out revenues due to in-out transactions because Midwest ISO charged on the basis of sinks both before and after the elimination of regional through-and-out rates, PJM charged for through-and-out revenues on the basis of points of delivery, which may not be the ultimate sink where the energy is consumed. AEP, Dayton, and Exelon contend that PJM transmission owners experienced lost revenues with points of delivery in Midwest ISO, regardless of whether a Midwest ISO transmission reservation was then used to deliver the energy to an ultimate sink outside of the combined region. In response to arguments that PJM transmission owners could double-collect revenues for transmission service via SECA charges and regional through-and-out rates, AEP, Dayton, and Exelon explain that PJM does not assess regional through-and-out rates to reservations with a point of delivery of Midwest ISO, regardless of whether the energy ultimately sinks in Midwest ISO.[138] While an in-out transaction may remain subject to regional through-and-out rates when it exits Midwest ISO, they maintain that the resultant revenues would not offset the lost through-and-out revenue when the energy moves from PJM into Midwest ISO. Moreover, they contend, intra-PJM SECA lost revenues could not have been remedied by any change in PJM's practice of charging on the basis of points of delivery because those designations are irrelevant upon a transmission provider's integration into PJM. Therefore, AEP, Dayton, and Exelon conclude that, if in-out revenues are not included in the development of SECA charges, then PJM transmission owners will experience lost revenues without a recovery mechanism.

---

[136] AEP, Dayton, and Exelon request that the Commission find that the point of delivery analysis contained in Dr. Henderson's rebuttal testimony properly identifies the revenues from in-out transactions that should be deducted.

[137] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 60 (*citing* Henderson Rebuttal Test., Ex. No. PTO-81 at 12:6-14:13, 23:14-34:13).

[138] *Id.* at 61-62 (*citing* Tr. 786:1-17, 782:18-22 (Dessender)).

128. Midwest ISO TOs argue that the Presiding Judge errs in finding that the proposed SECA charges ultimately provided Midwest ISO TOs with double compensation. Midwest ISO TOs maintain that their witness, Mr. Heintz, removed from the SECA obligations all revenues and MWhs sinking outside of the combined region. Midwest ISO TOs contend that, because Mr. Heintz applied the average rates only to the MWhs sinking in the combined region, the resulting rates recover only the portion of the revenues of Midwest ISO TOs associated with the eliminated regional through-and-out rates for transactions sinking in the combined region.[139] Furthermore, Midwest ISO TOs claim that, even if a transaction was incorrectly identified by the North American Electric Reliability Corporation tag data as sinking in the combined region when it ultimately sank elsewhere, that does not mean double compensation occurred because, while the transaction would have been included in SECA obligations, it would not have been assessed a charge under regional through-and-out rates. Thus, Midwest ISO TOs contend that, even if the SECA were assessed wrongly, it would result in the collection of one rate instead of the other and not in the collection of two rates.

129. While they did not propose any hubbing adjustments, Midwest ISO TOs support Dr. Henderson's analysis of Duke's hubbing adjustment.[140] Similarly, AEP, Dayton, and Exelon state that they made adjustments to reflect Duke and Allegheny's generation-only control area hubbing adjustment.[141]

130. In addition, AEP, Dayton, and Exelon contend that the Initial Decision incorrectly characterizes AEP's adjustment for transactions between AEP-East and AEP-West as hubbing transactions,[142] but did not render any corresponding findings in the hubbing section. They argue that the adjustment to reduce AEP's test-period through-and-out revenues to reflect these transactions is reasonable and is not properly characterized as a hubbing adjustment, as explained by Mr. Bethel.[143] They maintain that the Initial Decision finds that the methodology used by Mr. Bethel to support AEP's lost through-

[139] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 30 (*citing* Heintz Cross-Answering Test., Ex. No. MTO-99 at 11:21-12:1).

[140] *Id.* at 15 (*citing* Tr. 891:11-16 (Engleman); *Midwest Indep. Transmission Sys. Operator, Inc., et al.*, 116 FERC ¶ 63,048 (2006) (certification of uncontested partial settlement regarding Duke's generation-only control areas)).

[141] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 69.

[142] *Id.* (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 321).

[143] *Id.* (*citing* Bethel Test., Ex. No. AEP-1 at 12:13-21).

and-out revenues is sufficiently supported, and thus, it appears that the Initial Decision accepts AEP's adjustment for transactions between AEP-East and AEP-West.[144]

131. Midwest ISO TOs and AEP, Dayton, and Exelon contend that the Initial Decision errs in criticizing the use of North American Electric Reliability Corporation tag data and note that the Commission previously directed the use of such tag data.[145] AEP, Dayton, and Exelon contend that they made the relevant, underlying data used in the determination of SECA charges available to all parties. They add that the Commission was aware of the limitations of such tag data, including that they do not identify specific loads in the Classic PJM area, prior to requiring transmission owners to use the tag data. They request that the Commission reverse the Initial Decision's findings concerning the tag data because they fail to comport with the Commission's previous orders and are unsupported by substantial record evidence. Midwest ISO TOs argue that they were not required to justify their use of North American Electric Reliability Corporation tag data and that the tag data was provided by an independent information source.[146] They maintain that the Presiding Judge incorrectly asserts that they had not verified the accuracy of the tag data because the tag data was necessarily reviewed for accuracy when Mr. Heintz adjusted the tag data to remove MWhs associated with grandfathered agreements and duplicate tags and to substitute subzonal data where available. In addition, Midwest ISO TOs claim that Mr. Heintz adjusted the tag data for certain subzones where transmission owners were able to assign more specific sink information.

132. Dominion contends that the Initial Decision errs by failing to discuss its argument that AEP's lost revenues should be adjusted to reflect the transmission rates that were changed by a Stipulation and Agreement that was accepted by the Commission in Docket No. ER05-751-000.[147] Dominion maintains that the changes in AEP's transmission rates due to the implementation of that settlement agreement resulted in a disparity between

---

[144] *Id.* (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 120).

[145] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 47 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 67); AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 50 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 66; February 2005 Order, 110 FERC ¶ 61,107 at P 38).

[146] Midwest ISO TOs note that the North American Electric Reliability Corporation tag data was provided by OATi, the entity that keeps the North American Electric Reliability Corporation energy scheduling data.

[147] Dominion Brief on Exceptions to the Initial Decision at 16 (*citing American Electric Power Service Corp.*, 113 FERC ¶ 61,294 (2005)).

AEP's SECA charges and its other transmission service charges. Specifically, Dominion says that, from November 1, 2005, to March 31, 2006, the monthly rate for firm point-to-point and network integration transmission service under that settlement agreement is a unit rate of $1.08106 per kilowatt-month in the AEP-East zone. However, Dominion states that the SECA charges for point-to-point service during that period is given as $1.42 per kilowatt-month, which is based on older, higher transmission rates charged by AEP to customers outside of its zone (while customers in the AEP-East zone paid the lower point-to-point rate). Dominion argues that the record does not justify why customers with loads that are external to AEP should be subject to higher rates. To resolve this issue, Dominion requests that the Commission require AEP to submit a compliance filing that recalculates its lost revenues, consistent with the settlement agreement.

3. Briefs Opposing Exceptions

133. Constellation argues that the average rate methodology violates the Commission's cost-causation principles. Constellation explains that, under these methodologies, the same average rate is applied to the load of every load-serving entity without regard to the amount of through-and-out transmission service that actually sank with a particular load-serving entity during the transition period. It claims that this approach could impose SECA charges on entities that would also pay the network service rate and would not have been subject to any through-and-out charges if regional through-and-out rates were still in place. Even where parties enjoy the same benefit due to the elimination of regional through-and-out rates (i.e., the amount they previously paid due to regional through-and-out rates was the same), Constellation argues that the party with a higher load factor is forced to pay a greater cost for the same benefit. Constellation maintains that the average rate does not consider load factor differences, which would cause a party that schedules more power during the test period to be assessed a greater SECA charge than a party with the same transmission reservation that was less utilized. Moreover, it contends that the average rate used to calculate the SECA charges for all load-serving entities was disproportionally high because the denominator in the average rate calculation was the MWhs scheduled to be imported (instead of the larger MWhs of transmission service reserved).

134. Quest, Strategic, and WPS Energy and Constellation maintain that the average rate method does not meet the Commission's requirement to allocate costs to load in proportion to the benefits that they incur due to the elimination of regional through-and-out rates, and thus, it does not matter whether the average rate was the least time-consuming calculation method. Quest, Strategic, and WPS Energy argue that Mr. Heintz and Dr. Henderson created a vastly over-complicated SECA methodology. Constellation contends that the method of matching North American Electric Reliability Corporation tag data with Open Access Same-Time Information System reference numbers in order to link cross-seam transactions to their final sinks would have provided a more accurate

determination of relative benefits. It argues that this more intensive method would not be a transactional charge because it would still be assessed based on the load served by the load-serving entity.

135. Quest, Strategic, and WPS Energy contend that the Presiding Judge correctly finds that the average rate methodology, and particularly the footprint method, is flawed. They note that AEP, Dayton, and Exelon support the use of the footprint method, despite the Commission's direction that the SECA be recovered for transactions crossing the Midwest ISO-PJM seam sinking in the combined region. Quest, Strategic, and WPS Energy argue that the footprint method is especially egregious because it assesses costs to load-serving entities within the combined region for transactions that sank outside of the region.

136. Consistent with the Initial Decision, Quest, Strategic, and WPS Energy and Midwest ISO TOs argue that the footprint method for calculating average rates should not be used. They contend that there is a mismatch between the numerator, which is the total through-and-out dollars for transactions that sank inside and outside of the combined region, and denominator, which is the MWhs of through-and-out transactions that sank within the combined region, causing the average rate to be overstated and shifting costs to load-serving entities. They explain that the numerator includes total through-and-out dollars, while the denominator includes only MWhs that sink within PJM, causing lost revenues collected from the Midwest ISO entities to be overstated and violating Commission precedent requiring consistency between the numerator and denominator in rate calculations.[148] Midwest ISO TOs submit that this mismatch improperly inflates the Midwest ISO entities' SECA obligations by $35.3 million.[149] Midwest ISO TOs contend that the total method that they used to determine average rates calculates the numerator and denominator on the same basis.

137. AMP-Ohio argues that the Commission should affirm the Initial Decision's findings regarding in-out transactions but should expand the corresponding remedy by adopting a modification proposed by AEP, Dayton, and Exelon. Consistent with the Initial Decision, AMP-Ohio contends that including revenues associated with transactions that serve load outside of the region would violate cost-causation principles because only load in the combined region must pay SECA charges. It maintains that the through-and-out revenues calculated for Classic PJM TOs assumed that any transmission to the PJM border creates recoverable lost revenue and did not evaluate ultimate sinks. It suggests

[148] Midwest ISO TOs Brief Opposing Exceptions to the Initial Decision at 25 (*citing Entergy Servs., Inc*., 85 FERC ¶ 61,163, at 61,651 (1998); *S. Minn. Mun. Power Agency v. N. States Power Co*. *(Minn.)*, 73 FERC ¶ 61,350, at 62,077-81 (1995)).

[149] *Id.* at 23 (*citing* Heintz Answering Test., Ex. No. MTO-94 at 5:1-10:14).

that PJM transmission owners are inequitably attempting to collect from load within the combined region lost revenues that they are unable to recover from load outside of the region that benefited due to the elimination of regional through-and-out rates. However, AMP-Ohio argues that AEP, Dayton, and Exelon are correct that the Initial Decision errs by limiting the reduction of recoverable lost revenues to only AEP, Dayton, and Exelon**,** asserting that a $2 million reduction in the lost revenues claimed by Classic PJM TOs is also appropriate.

138. Four TDUs, Green Mountain, and Midwest ISO TOs contend that, consistent with the Initial Decision, lost revenues should not include in-out transactions. Even if in-out revenues are lost and independently verified as such, Midwest ISO TOs argue that the Commission did not eliminate regional through-and-out rates for transactions that sank outside of the combined region and limited the lost revenues that may be recovered via SECA charges to transactions that serve load within the combined region.[150] Four TDUs and Green Mountain explain that lost revenues due to the elimination of regional through-and-out rates for in-out transactions should not be recoverable via SECA charges because PJM voluntarily chose to eliminate regional through-and-out rates for in-out transactions and was not ordered to do so by the Commission. Four TDUs add that Midwest ISO successfully charged for in-out paths during the transition period, and PJM transmission owners, like BG&E, could have exercised their rights under the PJM TO Agreement[151] to require PJM to change that voluntary choice. Green Mountain maintains that the Commission has no obligation to provide revenue recovery where a public utility has voluntarily eliminated rate pancaking without a lost revenue recovery mechanism.[152] It adds that load-serving entities within Midwest ISO derived no benefit from PJM's decision to eliminate regional through-and-out rates on in-out transactions, and thus, including these transactions in the calculation of lost revenues would violate the Commission's requirement that the SECA be charged in proportion to the benefits due to the elimination of regional through-and-out rates. Four TDUs object that significant amounts of their SECA obligation to BG&E includes test-period revenues associated with deliveries to loads located outside of the combined region.[153] To remedy these

[150] *Id.* at 21 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at 14; November 2004 Order, 109 FERC ¶ 61,168 at 66).

[151] PJM, Rate Schedule FERC No. 42, Consolidated Transmission Owners Agreement (PJM TO Agreement).

[152] Green Mountain Brief Opposing Exceptions to the Initial Decision at 18-19 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 42).

[153] Four TDUs explain that Classic PJM's 2003 test-period lost revenues include substantial revenues associated with a terminated series of four monthly 308 MW reservations to Dominion that, when they were used, sank, in part, outside of the

(continued…)

problems with the average rate method, Four TDUs support the total method, as identified by Mr. Solomon.

139. Midwest ISO TOs argue that the footprint method and inclusion of in-out revenues violates the Commission's cost-causation principles.[154] Midwest ISO TOs maintain that entities in Midwest ISO do not benefit from transactions that sank outside of the combined region, regardless of whether they crossed the Midwest ISO-PJM border. They contend that they have no responsibility to make companies whole for lost revenues due to such transactions because they did not cause such losses to be incurred.

140. When considering in-out transactions, Constellation argues that AEP, Dayton, and Exelon failed to determine where transactions ultimately sank and instead based their lost revenues on a transaction's point of delivery to maximize their revenues. Constellation points out that a transaction's point of delivery is not always the same as its sink, and thus, including revenues from in-out transactions violates cost-causation principles by forcing load-serving entities to pay when they did not benefit from the imported power.

141. Constellation claims that PJM chose to assess regional through-and-out rates based on the point of delivery, and if AEP, Dayton, and Exelon disapproved due to their lost revenues, they should have sought to change PJM's procedures through the stakeholder process.

142. BG&E contends that the request of AEP, Dayton, and Exelon to consider in-out revenue is impermissible because they cannot use a compliance filing to newly propose a basis for increasing SECA charges. BG&E adds that the Commission has ruled that excluding transactions that exited the combined region is a mandatory hubbing adjustment.[155] BG&E and Constellation state that, for transactions that ultimately sink outside of the combined region, there is no lost revenue to be made up through the SECA, and thus, over recovery would occur if the SECA reflected the costs of moving power to regions where regional through-and-out rates have not been eliminated. BG&E states that Mr. Heintz' approach is incorrect because, if the point of delivery is outside of the combined region, that transaction is not within the prescribed category of transactions

---

Combined Region. Four TDUs Brief Opposing Exceptions to the Initial Decision at 15 (*citing* Tr. 1387:8-11 (Bustard)).

[154] Midwest ISO TOs Brief Opposing Exceptions to the Initial Decision at 24 (*citing*, *e.g.*, *Cities of Riverside & Colton*, 765 F.2d 1434, 1439 (9th Cir. 1985)).

[155] BG&E Brief Opposing Exceptions to the Initial Decision at 11 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 80).

with both a source and a sink within the combined region to which the SECA applies, even if the transaction later reenters the combined region.

143. AMP-Ohio contends that, if the Commission requires the submission of compliance filings, it should require the parties to incorporate the unopposed average rate adjustments made in Dr. Henderson's supplemental direct testimony. In order to correct a major error to reflect that a 616 MW reservation during calendar-year 2003 with an initial point of delivery in Dominion was in fact redirected to NYISO, Dr. Henderson in his supplemental testimony excluded $12,893,916, or 41 percent, from previously estimated lost revenues, reducing the average rate from $7.2394 to $4.2814.[156] In light of these significant adjustments, AMP-Ohio requests that the Commission carefully scrutinize each of the data inputs to the calculation of PJM average rates.

144. BG&E contends that Mr. Bethel improperly included out-in transactions so as to increase the SECA. BG&E contends that Mr. Bethel did not identify transactions that sank outside of the combined region to decrease the SECA, as required by the Commission. BG&E submits that Mr. Bethel did the reverse of the Commission's directive by instead identifying out-in transactions, which exited the combined region and reentered to sink within the region, in order to increase the SECA. BG&E argues that the Commission was "fully cognizant" that they were approving a one-way, downward adjustment to the SECA by requiring hubbing adjustments, which would not include increasing the SECA to consider out-in transactions.[157] BG&E concludes that the Commission intended the hubbing adjustment to prevent over collections under the SECA rather than to be used as a method to inflate the SECA. Moreover, even if the Commission intended the SECA to be increased by out-in transactions, BG&E states that Mr. Bethel has not submitted work papers to support the adjustments.

145. BG&E also contends that, while Mr. Bethel reduced AEP's lost revenues by $4.26 million to account for transactions from AEP-East to AEP-West, Mr. Bethel ignored known hubbing adjustments for transactions traveling in the opposite direction. BG&E argues that Mr. Bethel omits approximately 2.2 million MWh of power transmitted from AEP-West to AEP-East. BG&E maintains that Mr. Bethel ignores provisions in AEP's tariff that allow a customer to pay one rate for service to both AEP zones and concludes

[156] AMP-Ohio Brief Opposing Exceptions to the Initial Decision at 17 (*citing* Henderson Supplemental Test., Ex. No. PTO-105 at 3-5).

[157] BG&E states that, at the November 13, 2003 Commission Meeting, Commission Staff stated that "the draft order also finds that the hubbing transactions should be excluded from the SECA." BG&E Brief Opposing Exceptions to the Initial Decision at 15 (*citing* November 13, 2003 Commission Meeting Tr. 42:9-10).

that using the same pricing in AEP-East and AEP-West would reduce AEP's lost revenues by $3.6 million.[158]

146. BG&E states that, according to Mr. Bourquin, routine hubbing that takes place in PJM's Western Hub is further delivered to the Northeast, but the North American Electric Reliability Corporation tag data lists only PJM Western Hub as the delivery point.[159] BG&E states that, contrary to AEP's method, it is reasonable to assume that any transaction with a Western Hub tag is identifying the first leg of a journey outside of PJM and, thus, should be eliminated from the SECA calculation. BG&E contends that transmission owners are inflating the SECA by using the partial tracking afforded by North American Electric Reliability Corporation tag data to draw faulty inferences that PJM was the sink of these transactions. BG&E states that the Commission should instead impute the most extreme assumptions as to hubbing possible, so that anything that was exported out of PJM by entities that imported power into PJM is assumed to have been hubbed and, therefore, should be excluded from lost revenue calculations. BG&E suggests that this assumption could be applied by using PJM's Enhanced Energy Scheduler data, which shows the total MWhs exported from PJM to all sources during the test years being used in the SECA filings.

147. AEP, Dayton, and Exelon argue that BG&E has adopted contradictory positions and request that the Commission disregard all of BG&E's collateral attacks on the Commission's orders.[160] They state that the Initial Decision relies heavily on BG&E's post-hearing briefs in its dismissal of the transmission owners' lost revenue claims, and BG&E continues to contend that the SECA methodology is retroactive ratemaking and that no compliance filing can ever be just and reasonable. However, they add, in Classic PJM TOs' Brief on Exceptions to the Initial Decision, BG&E asks that the Commission reverse the Initial Decision's findings with respect to its own lost revenue claim, so that it may collect its lost revenues.

148. Quest, Strategic, and WPS Energy contend that North American Electric Reliability Corporation tag data is not appropriate for calculating a transition charge. They explain that there is no revenue information associated with the tags, and they are not traceable to sinks in the Classic PJM area or the Midwest ISO market as of April 1, 2005. According to Quest, Strategic, and WPS Energy, utilizing North American Electric Reliability Corporation tags is a laborious process because duplicate tags must be

[158] *Id.* at 20-21 (*citing* Bourquin Test., Ex. No. CTO-4 at 12:8-19).

[159] *Id.* at 22-23 (*citing* Bourquin Test., Ex. No. CTO-4 at 13:4-18).

[160] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 9-10.

removed, and one power delivery transaction from source to sink could contain multiple segments that must be matched.

149. AEP, Dayton, and Exelon contend that Dominion's proposed revision to AEP's lost revenues to reflect AEP's zonal rates included in the Stipulation and Agreement in Docket No. ER05-751-000 and filed as AEP's last transmission rate case is without merit and should be denied. They state that the rates established in that settlement agreement are not through-and-out rates and are not test-period rates. Instead, those rates are zonal ones that apply to reserved capacity for deliveries to the AEP zone within PJM, according to AEP, Dayton, and Exelon, which cannot form the basis for measuring through-and-out revenues for SECA purposes.[161] They add that Dominion's proposal would result in trapped costs for AEP because the rates in that settlement agreement reflect the level of SECA revenues that AEP expected to receive, in order to pass along the benefit of SECA revenues to its load.

4. Commission Determination

150. We find the utilization of average rates when determining SECA charges to be consistent with the Commission's previous directives. The Commission previously rejected the use of actual invoices, rather than North American Electric Reliability Corporation tag data, when determining SECA charges, stating that using actual test-period invoices "could lead to under recovery of lost revenues and produce unfair results."[162] Further, the Commission rejected the use of actual transition period usage to true-up SECA data, finding that it would "essentially convert the SECA back into a transactional charge for [through-and-out] service, thus recreating the impacts of rate pancaking which we are eliminating."[163] Given these restrictions, we find the use of North American Electric Reliability Corporation tag data and average rates by Mr. Heintz and Dr. Henderson to be appropriate. As Mr. Heintz explained, utilizing an average rate is necessary because it is almost impossible to calculate directly the transmission charges paid to other transmission owners by a given load due to the increased number of transactions involving power marketers that do not have detailed bills showing the amount of transmission charges paid by the power marketers.[164]

---

[161] AEP, Dayton, and Exelon add that the zonal rates were designed using 1-CP billing determinants and cannot serve as a proxy for its prior regional through-and-out rates, which were designed using 12-CP billing determinants. *Id.* at 57-58, n.200.

[162] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 67.

[163] *Id.* P 64 n.117.

[164] Heintz Test., Ex. No. MTO-1 at 23:17-24:3.

151. Contrary to the Initial Decision, we will not reject the use of average rates because they could shift costs from parties with low load factors to parties with high ones. Remedying any such cost shifts would entail the evaluation of how individual loads make use of their transmission reservations, and as noted above, the Commission previously rejected the use of actual invoices when determining the SECA. Moreover, as Dr. Henderson explained, tracing how particular reservations were used to deliver energy through Open Access Same-Time Information System Assignment Reference numbers to account for load factor utilization differences under each separate transaction, as suggested by Constellation, is impractical due to power marketing arrangements and the redirection of reservations to alternate sinks.[165] Furthermore, a principal benefit of the elimination of regional through-and-out rates is increased trading and the resulting tendency to equalize delivered prices at various locations.[166] Merely holding reserved transmission capacity would not produce such benefits until energy is actually scheduled for delivery using a reservation. Therefore, delivered energy may be better than reserved transmission capacity at indicating the relative benefits of the elimination of regional through-and-out rates, which would justify allocating lost revenues to parties based on their use of transmission reservations (i.e., to those parties with relatively high load factors). In addition, the average rate methodology does not result in over-recovery, as Constellation suggests, because the average rate was applied to scheduled MWhs, not reserved MWhs.

152. Notwithstanding our support for the utilization of average rates in this proceeding, we find Dr. Henderson's use of in-out transactions when determining average rates to be unjust and unreasonable. The SECA charge is not the appropriate vehicle for PJM transmission owners to recover lost revenues associated with the elimination of regional through-and-out rates for in-out transactions. PJM voluntarily eliminated such regional through-and-out rates and, as the Initial Decision correctly notes, was not required to do so by the Commission.[167] The Commission has no obligation to establish a lost revenue recovery mechanism where transmission owners voluntarily agreed to eliminate rate

---

[165] *See* Henderson Test., Ex. No. PTO-1 at 14:14-18; *see also Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945) ("allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.").

[166] Henderson Test., Ex. No. PTO-1 at 17:11-21.

[167] Initial Decision, 116 FERC ¶ 63,030 at P 126 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 14 ("[a]s to the scope of the elimination of [regional through-and-out rates], we will eliminate [regional through-and-out rates] for new transactions sinking in the combined region")).

pancaking without a lost revenue recovery mechanism,[168] and we decline to do so here. Moreover, we find that including in-out transactions in the numerator, but not the denominator, of the average rate determination inflates the average rate and unfairly shifts costs to load-serving entities.[169] Assigning the costs associated with PJM's voluntary elimination of regional through-and-out rates to load within the combined region in this manner is inconsistent with the Commission's cost-causation principles. The primary benefit of eliminating regional through-and-out rates for in-out transactions is expected to accrue to load zones outside of the combined region where the energy ultimately is consumed, as opposed to intermediate load zones inside of the combined region whose local transmission provider merely provided transmission service in moving the power to its ultimate destination. Accordingly, we direct the PJM transmission owners to remove revenues associated with in-out transactions from the numerator of the average rate such that the inputs for the numerator of the average rate determination correspond to the inputs for the denominator. We will require the PJM transmission owners to submit revised SECA charges to reflect the adjustment adopted here in the compliance filings ordered below.

153. We disagree with the argument that Mr. Heintz' average rate determination improperly included transactions that sank outside of the region to overcharge the PJM entities or to permit double compensation for the Midwest ISO transmission owners. When determining average rates for the Midwest ISO transmission owners, Mr. Heintz correctly included revenues and MWhs associated with reservations with non-PJM points of delivery that may have been used for transactions that sank outside of the combined region because he could not rule out that the reservations may have been used for transactions that ultimately reentered and sank within the combined region.[170] However, when determining the SECA obligation for the PJM entities, Mr. Heintz did not include any MWhs that sank outside of the combined region, and thus, the PJM entities were not assessed additional SECA charges based on MWhs that sank outside of the combined region.[171]

---

[168] *See* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 42.

[169] We note that, according to Midwest ISO TOs, this mismatch between the numerator and denominator improperly inflates the Midwest ISO entities' SECA obligations by $35.3 million. Midwest ISO TOs Brief Opposing Exceptions to the Initial Decision at 23 (*citing* Heintz Answering Test., Ex. No. MTO-94 at 5:1-10:14).

[170] Mr. Heintz removed revenues and MWhs that exited the Combined Region via the Midwest ISO – Ontario Hydro interface because he believed that such transactions were unlikely to reenter the region.

[171] Heintz Rebuttal Test., Ex. No. MTO-103, 23:18-24:7.

154. We agree with Midwest ISO TOs' argument that the Initial Decision's objections to in-out transactions do not apply to Mr. Heintz' average rate determination. We note that, to the extent that Mr. Heintz included transactions that ultimately sank outside of the combined region when determining average rates, he included the associated revenues in the numerator and MWhs in the denominator, thereby avoiding any mismatch between the numerator and denominator of his average rate calculation. We find that Midwest ISO TOs have developed an average rate methodology that allocates SECA costs to load in proportion to their benefits due to the elimination of regional through-and-out rates in a just and reasonable manner and, thus, has complied with the Commission's previous directives.

155. Consistent with AMP-Ohio's request, we will direct the PJM transmission owners to incorporate the unopposed $12,893,916 adjustment to the numerator of the PJM average rate calculation for the 2003 test period. As Dr. Henderson explained, the numerator of PJM's calendar-year 2003 lost revenue calculations included $13,159,608 revenues associated with a 616 MW reservation held by Exelon with a point of delivery to Dominion.[172] Accordingly, we will require the PJM transmission owners to submit revised SECA charges to reflect the adjustment adopted here in the compliance filings ordered below. However, Dr. Henderson has since learned that 97.98 percent of the energy delivered under this reservation was redirected to NYISO, and while the MWh associated with such deliveries had been excluded from the denominator of the average rate calculation, the revenues were still included in the numerator.[173] We agree that, as these deliveries did not ultimately sink within the combined region, they should not be included in PJM's lost revenue calculations.

156. We find increasing AEP's lost revenues to reflect out-in transactions to be just and reasonable because AEP will lose revenues due to the elimination of through-and-out charges assessed on transactions that sink within the region. BG&E does not provide evidence indicating that AEP would not lose revenues due to such out-in transactions, and we note that Mr. Bethel's testimony and Exhibit No. AEP-2 suggest that AEP's lost revenues associated with out-in transactions could be significant.[174] Further, we disagree with BG&E's characterization of out-in transactions as being "hubbing" transactions.

---

[172] Henderson Supplemental Test., Ex. No. PTO-105 at 3:15-4:2.

[173] *Id.* 4:3-18.

[174] As Mr. Bethel explained, for example, 4.9 million MWh initially exited AEP for points of delivery outside of the Combined Region but ultimately terminated in a load control area within the region, and, if such out-in transactions are not reflected in AEP's lost revenues, AEP will fail to recover $12.7 million. Bethel Test., Ex. No. AEP-1 at 11:19-20:5; *see also* AEP 2002 Through-and-Out Revenues, Ex. No. AEP-2 at 1:11.

While hubbing transactions are identified by matching two or more North American Electric Reliability Corporation tags and supporting that they formed a single transaction, Mr. Bethel's out-in transactions were scheduled using a single North American Electric Reliability Corporation tag, and thus, they are not considered hubbing.[175] Therefore, the Commission's intent when accepting hubbing adjustments is not relevant to our consideration of out-in transactions.

157. In addition, we find that BG&E's failure to support any hubbing adjustments to reduce the SECA does not render other lost revenue adjustments unjust or unreasonable. We find Duke's and Allegheny's uncontested generation-only control area hubbing adjustment to be just and reasonable, and we will require Midwest ISO TOs and the PJM transmission owners to submit revisions to reflect those adjustments, as applicable, in the compliance filings ordered below. As Dr. Henderson explained, generation-only control areas have no load other than energy needed for station power,[176] and thus, it is reasonable to conclude that energy delivered to generation-only control areas was exported under a separate, second tag and ultimately sank elsewhere.[177]

158. We agree that AEP's lost revenues were appropriately reduced by $4.26 million to account for transactions from AEP-East to AEP-West. No party contested this adjustment, and as Mr. Bethel explained, he excluded revenues associated with internal transfers from AEP-East to AEP-West because AEP "could have used the provision of its tariff that allows a customer that pays the rate for transmission service in one zone to use the facilities in another zone without additional charge."[178] However, we find that BG&E has not shown that AEP's lost revenues should be reduced by $3.6 million to account for further transactions from AEP-West to AEP-East. BG&E has not demonstrated that Mr. Bethel improperly considered these transactions in his most recent calculation of AEP's

[175] Bethel Test., Ex. No. AEP-1 at 12:13-21.

[176] Duke and Allegheny have stated that wholesale energy delivered to their respective generation-only control areas was not used for station power because any such station power is instead provided under retail tariffs.

[177] *See* Henderson Test., Ex. No. PTO-1 at 26:7-21.

[178] Mr. Bethel also stated that, rather than using the available non-firm network service, AEP reserved long-term firm point-to-point service out of AEP-East, and through the Ameren system, to firmly integrate its east and west systems. Bethel Test., Ex. No. AEP-1 at 13:11-22.

lost revenues and, thus, no adjustment may be needed.[179] The adjustment for transactions from AEP-East to AEP-West is necessary because AEP included revenues for reservations through or out of the AEP-East system for delivery to Ameren regardless of where the transaction sank (including AEP's own use of its system to transmit power for ultimate delivery to the AEP-West companies over its contract path on the Ameren system). In contrast, no revenues for the use of the AEP-West system for delivery to the AEP-East system are included in AEP's claimed lost revenues, and therefore, no adjustments for AEP's transfers from AEP-West to AEP-East are necessary.

159. We reject BG&E's unsubstantiated allegation that vast amounts of imports with a PJM Western Hub tag were hubbed and then exported outside of the combined region. As Dr. Henderson explained, a transaction to move power to the PJM Western Hub with the intent to then export the power outside of the combined region should have been entered on a *single* North American Electric Reliability Corporation tag and would already have been excluded from the SECA calculations, making a further hubbing adjustment unnecessary.[180] To the extent that similar transactions were made using *separate* North American Electric Reliability Corporation tags, BG&E has provided no evidence supporting the assumption that such transactions should be removed from the SECA calculations. As Dr. Henderson explained, for example, if power prices in NYISO exceed those in PJM and prices in PJM exceed those in Midwest ISO, then the relative price differences will result in power being imported to PJM from Midwest ISO and exported from PJM to New York. However, such simultaneous imports and exports of power may reflect independent trading activity on opposite borders of PJM, rather than hubbing transactions in which a trader intends to move power from Midwest ISO to New York via PJM,[181] and thus, such transactions should not be removed from the SECA calculations. Therefore, we will not grant BG&E's request to apply the most extreme hubbing assumptions possible to the SECA calculations by removing all transactions with a Western Hub tag or all transactions exported out of PJM by entities that also imported power into PJM.

---

[179] We note that, as support for AEP's argument, Mr. Bourquin included AEP's previous Exhibit No. AEP-4, but this exhibit was superseded by Mr. Bethel's subsequent testimony and Exhibit No. AEP-2. Bourquin Test., Ex. No. CTO-4 at 12:6-20.

[180] Henderson Cross-Answering Test., Ex. No. PTO-80 at 18:7-19:4. Further, we note that, as such transactions involve only a single North American Electric Reliability Corporation tag, they would not be considered hubbing.

[181] *Id.* 19:5-23. In contrast, if prices were lowest in PJM and highest in NYISO, power suppliers in Midwest ISO would not have an economic incentive to export power to PJM, but they would have an incentive to export to NYISO by using PJM as a hub. *Id.* 20:3-15. However, BG&E has not provided evidence that such hubbing occurred.

160. Contrary to the Initial Decision, we will affirm that the use of North American Electric Reliability Corporation tag data when calculating the SECA charges was appropriate and is consistent with previous Commission directives. We recognize that utilizing such tag data to develop and to verify the accuracy of the complex SECA rate was undoubtedly a laborious process. However, the fact that formulating the SECA was difficult does not render the resultant rates unjust and unreasonable. The Initial Decision uses the existence of transactions that were improperly included in the SECA calculations as a basis to reject the compliance filings, but we find that the ability of parties to identify these transactions supports our finding that using North American Electric Reliability Corporation tag data as the basis for the SECA calculation is appropriate.

161. We note that Mr. Heintz and Dr. Henderson made numerous adjustments in order to improve the North American Electric Reliability Corporation tag data, and all of the relevant underlying information has been made available for parties to review as part of the record of this proceeding, which provides parties with the ability to verify the calculations and an opportunity to propose adjustments, as needed, to improve the accuracy of the SECA. Furthermore, as previously explained by the Commission, the alternative to using the tag data (i.e., using actual test-period invoices) "could lead to under recovery of lost revenues and produce unfair results" because many of the transmission customers are power marketers that can change their level of trading activity from year to year and may have exited the market since the test period.[182] In addition, we note that, in previous orders, the Commission specifically required the use of North American Electric Reliability Corporation tag data in developing the SECA, stating that "[a]s a general matter, we believe that any such filing should use [North American Electric Reliability Corporation] tag data."[183] The Commission also required the RTOs and their transmission owners to include North American Electric Reliability Corporation tag data as part of their supporting documentation for the development of the proposed SECA rates.[184]

162. Finally, in regard to Dominion's request that the Commission require AEP to recalculate its lost revenues to reflect a Stipulation and Agreement that was previously accepted by the Commission in Docket No. ER05-751-000, we note that the Commission did not require transmission owners to file updated rates in order to justify their level of SECA charges, stating that "[s]uch a requirement could create an unnecessary impediment to RTO formation."[185] The Commission also found that the parties "did not

[182] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 67.

[183] July 2003 Order, 104 FERC ¶ 61,105 at P 54.

[184] February 2005 Order, 110 FERC ¶ 61,107 at P 38.

[185] July 2003 Order, 104 FERC ¶ 61,105 at P 51.

convincingly show that the existing rates were unjust and unreasonable" and indicated that, if any customer believes that the existing rates and revenues that form the basis of the SECA are no longer just and reasonable, it may file a complaint pursuant to section 206 of the FPA.[186] Since Dominion made no such showing, we will not require AEP to recalculate its lost revenues, consistent with the Commission's previous findings.

E. Inclusion of Single Company Tariff Revenues

1. Initial Decision

163. The Initial Decision finds that only transmission service between the two RTOs was to be included in the SECA mechanism. The Initial Decision finds the inclusion of intra-RTO lost revenues in the SECA mechanism to be unjust and unreasonable.[187] AEP, ComEd, and Dayton joined PJM on December 1, 2004, before the elimination of regional through-and-out rates, but after the test period. The Initial Decision finds that the lost revenues for these companies should have included one charge for crossing into or out of the PJM or Midwest ISO borders (i.e., inter-RTO) instead of multiple charges for crossing each transmission owners' borders (i.e., intra-RTO) as was in effect during the test period.

164. The Initial Decision also finds that AEP, Dayton, and Exelon may not include as lost revenues those revenues that they were unable to collect due to a lack of provisions in the PJM tariff.[188] The Initial Decision states that the PJM tariff, not Commission orders, prohibited AEP, Dayton, and Exelon from recovering revenues for transmission service provided through or out of its network if the point of delivery is Midwest ISO, regardless of the sink. The Initial Decision states that PJM or AEP, Dayton, and Exelon could have proposed new tariff provisions to correct this discrepancy in a separate section 205 filing.

2. Briefs on Exceptions

165. AEP, Dayton, and Exelon argue that the Initial Decision errs in finding that the SECA only included the through-and-out charges incurred due to crossing the Midwest ISO-PJM border. AEP, Dayton, and Exelon assert that the Commission required that some transmission owners not yet integrated into their respective RTOs eliminate their regional through-and-out rates and claim that the Commission provided the SECA

---

[186] *Id.* P 51, n.83.

[187] Initial Decision, 116 FERC ¶ 63,030 at P 131.

[188] *Id.* P 134.

mechanism to recover these intra-RTO revenues as well as inter-RTO revenues.[189] AEP, Dayton, and Exelon argue that joining an RTO prior to December 2004 did not alter the SECA requirements. AEP, Dayton, and Exelon state that the SECA rate design is based on test periods utilized to develop load-based charges to maintain revenue from all through-and-out charges that would apply to new transactions between and within the RTOs had those charges not been eliminated. AEP, Dayton, and Exelon assert that to find otherwise would penalize those transmission owners subject to the Ameren 2003 Order for joining an RTO prior to the elimination of regional through-and-out rates. AEP, Dayton, and Exelon argue that the Initial Decision allows load to shift the costs due to the elimination of regional through-and-out rates to AEP, Dayton, and Exelon's customers.

166. AEP, Dayton, and Exelon also contend that, if the Commission did not intend to include these revenues in the SECA mechanism, it would never have conditionally accepted the SECA compliance filings containing these intra-RTO through-and-out revenues. AEP, Dayton, and Exelon also take exception to the Initial Decision's finding that the Commission's orders were ambiguous or that the Commission changed its position.[190] AEP, Dayton, and Exelon argue that the Commission consistently promoted a policy of revenue neutrality and, in the November 2004 Order, stated that "where the Commission is addressing inter-RTO rate pancaking, it is appropriate to apply the Commission's prior policies for addressing the elimination of rate pancaking within an RTO."[191]

167. AEP, Dayton, and Exelon assert that the Initial Decision errs in rejecting their inclusion of intra-RTO lost revenues. They argue that, in the November 2004 Clarification Order, the Commission granted AEP's Motion for Clarification of the Commission's November 2004 Order and clarified that AEP, Dayton, and Exelon could recover these lost intra-RTO revenues through the SECA proceedings.[192] In addition, AEP, Dayton, and Exelon argue that, in the February 2005 Order conditionally accepting the compliance filings, the Commission denied a request to reject the intra-PJM lost revenues and stated, "[i]n the November [2004 Clarification] Order, we clarified that lost

[189] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 39-40 (*citing Ameren Services Co*., 105 FERC ¶ 61,216, at P 59 (Ameren 2003 Order)).

[190] *Id.* at 42 (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 112).

[191] *Id.* at 43 (*citing* November 2004 Order, 109 FERC ¶ 61,168 at P 58).

[192] *Id.* at 46 (*citing* November 2004 Clarification Order, 109 FERC ¶ 61,243 at P 9).

revenues associated with the elimination of intra-RTO rate pancaking could be recovered through the same [SECA] methodology."[193]

168. Midwest ISO TOs object to the Initial Decision's limiting the SECA to inter-RTO revenues as it unfairly impacts the Midwest ISO transmission owners that joined Midwest ISO during or after the test period. Midwest ISO TOs argue that this limitation would cause some transmission owners to recover only a portion of their lost revenues. For example, Midwest ISO TOs state that entities such as ATSI, METC and NIPSCO, which joined Midwest ISO after February 2002 but prior to the end of the 2003 test year, would be limited to recovering only a portion of their lost revenues even though these companies did not assess through-and-out charges during the entire transition period. Furthermore, Ameren, which joined Midwest ISO in 2004, after the test period, would be prohibited from recovering any lost revenues even though it also did not assess through-and-out charges during the transition period. Midwest ISO TOs assert that, since the test-period data was to be used to approximate the revenues lost as of December 1, 2004, entities should be allowed to use historical data regarding regional through-and-out rates for the entire test period, not just for the months that they were members of Midwest ISO.

169. Midwest ISO TOs assert that by excluding individual company tariff revenues the Initial Decision prohibits all of the Midwest ISO transmission owners from recovering lost revenues calculated during the test period from January 1, 2002, through January 31, 2002, because Midwest ISO did not begin tariff operations until February 1, 2002. Midwest ISO TOs assert that this would result in an unfair penalty to all of the Midwest ISO transmission owners and request that the Commission reverse this portion of the Initial Decision, as it applies to the Midwest ISO transmission owners.

170. Constellation states that it supports the Initial Decision's finding that transmission owners inflated their lost revenues by including intra-RTO transactions. Constellation and Green Mountain agree with the Initial Decision's finding that AEP, Dayton, and Exelon should recalculate their lost revenues so that they only include lost revenues from crossing the Midwest ISO-PJM border (i.e., removing any intra-RTO lost revenues).

171. Four TDUs argue that the Commission limited the intra-RTO lost revenue recovery to AEP, ComEd, and Dayton, thereby excluding any other intra-RTO recovery by Classic PJM TOs.

3. Briefs Opposing Exceptions

172. Constellation opposes AEP, Dayton, and Exelon's exceptions to the Initial Decision and supports the Initial Decision's finding excluding intra-RTO revenues from

---

[193] *Id.* (*citing* February 2005 Order, 110 FERC ¶ 61,107 at P 37).

the SECA mechanism.[194] Constellation argues that upon joining PJM AEP, Dayton, and Exelon would not have received any revenues for service within PJM just like the transmission owners that joined Midwest ISO after the test period and are not entitled to receive revenues for service within Midwest ISO. Constellation argues that the Initial Decision follows the Commission's decision in providing for the recovery of revenues lost as a result of the Commission's elimination of regional through-and-out rates between PJM and Midwest ISO.

173. Green Mountain also opposes the inclusion of intra-RTO revenues, arguing that PJM voluntarily chose to eliminate those regional through-and-out rates, and the elimination of those rates do not result in benefits for load-serving entities in Midwest ISO.[195] Quest, Strategic, and WPS Energy support the Initial Decision's finding that only the single cross-border inter-RTO charge should be used to develop lost revenues.

174. Four TDUs assert that Classic PJM transmission owners should not be allowed to collect any SECA charges from loads in the Dominion zone because those revenues were eliminated due to their voluntarily joining PJM and not due to the Commission's de-pancaking mandate. Four TDUs argue that, in its November 2004 Clarification Order, the Commission limited intra-RTO recovery to AEP, ComEd, and Dayton but did not extend the intra-RTO recovery to other companies, such as BG&E.[196]

175. Quest, Strategic, and WPS Energy argue that AEP, ComEd, and Dayton joined PJM before the Commission eliminated regional through-and-out rates on December 1, 2004. As of December 1, 2004, they state that there was only one charge for leaving PJM regardless of how many PJM transmission owners' borders were crossed prior to leaving PJM.[197] Quest, Strategic, and WPS Energy contend that, since the Commission only eliminated the regional through-and-out rate for crossing the Midwest ISO-PJM border, only lost revenue from such transactions should be included in the SECA. They argue that these companies chose to join PJM, thereby creating the irregular seam in the first place, and by collecting intra-RTO lost revenues through the SECA, are forcing others to pay for their choice. Quest, Strategic, and WPS Energy add that any lost revenues that

---

[194] Constellation Brief Opposing Exceptions to the Initial Decision at 19-21.

[195] Green Mountain Brief Opposing Exceptions to the Initial Decision at 18-19 (*citing* Tr. 1212:18-1216:22 (Henderson)).

[196] Four TDUs Brief Opposing Exceptions to the Initial Decision at 9 (*citing* November 2004 Clarification Order, 109 FERC ¶ 61,243 at P 9).

[197] Quest, Strategic, and WPS Energy Brief Opposing Exceptions to the Initial Decision at 51.

AEP, Dayton, and Exelon incur is due to PJM's license plate tariff design and their choice to join PJM. Thus, Quest, Strategic, and WPS Energy maintain that AEP, Dayton, and Exelon's customers should bear the cost of those choices, not others. They further assert that the SECA was designed for companies to recover lost revenues resulting from transactions that cross the Midwest ISO-PJM border and sink within the combined region, not for transactions that simply cross intra-RTO borders.

4. Commission Determination

176. We disagree with the Initial Decision's finding limiting the SECA to inter-RTO lost revenues. The Commission has long recognized that the replacement of rate pancaking with license plate rates in this region of the Midwest, for both intra-RTO service and inter-RTO service, would result in significant immediate cost shifts to the local customers of certain transmission owners.[198] While the Commission initially declined to establish a transitional lost revenue recovery mechanism to accompany license plate rates as the replacement for inter-RTO rate pancaking in the July 2003 Order, it reversed itself on rehearing and adopted the transitional SECA as part of the replacement rate in order to satisfy the requirements of section 206 of the FPA to establish a just and reasonable replacement rate (i.e., replacement of inter-RTO rate pancaking with license plate rates without a transitional lost revenue recovery mechanism would have been unjust and unreasonable). Likewise, the replacement of intra-RTO rate pancaking with license plate rates without a transitional lost revenue recovery mechanism upon AEP, ComEd, and Dayton's integration into PJM was unjust and unreasonable, and the Commission remedied that situation in the November 2004 Clarification Order, as we affirm in the order on rehearing being issued concurrently. As we stated in the November 2004 Clarification Order, AEP, ComEd, and Dayton are in a different position than other transmission owners because they were integrated into PJM in the midst of the inter-RTO rate proceedings and had not had the opportunity to fully recover their lost revenues associated with the elimination of intra-RTO rate pancaking.[199] Therefore, AEP, ComEd, and Dayton may recover lost revenues associated with the elimination of intra-RTO rate pancaking through the SECA transition methodology in Docket No. EL04-135-000.

177. In addition, while the Commission adopted this intra-RTO lost revenue recovery mechanism to address the situation of AEP, ComEd, and Dayton, the intra-RTO lost revenue recovery is not limited to these companies. Instead, the SECA mechanism is

---

[198] *See Alliance Companies*, 94 FERC ¶ 61,070 (2001); *Alliance Companies*, 99 FERC ¶ 61,105 (2002); November 2003 Rehearing Order, 105 FERC ¶ 61,212; and Ameren 2003 Order, 105 FERC ¶ 61,216. *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,090, at P 15 (2003).

[199] November 2004 Clarification Order, 109 FERC ¶ 61,243 at P 9.

reciprocal (i.e., any transmission owner whose zone is subject to an intra- and/or inter-RTO SECA obligation should also be able to recover an intra- and/or inter-RTO SECA). Therefore, it extends to all transmission owners within PJM that lost revenues due to the elimination of rate pancaking for transmission service to serve load within PJM during the period that the SECA is in effect (compared to the test period), as well as to the PJM and Midwest ISO transmission owners that lost revenue due to the elimination of rate pancaking for transmission to serve load in the other RTO during the period that the SECA is in effect (compared to the test period).

F. Adjustments for Grandfathered Contracts

1. Initial Decision

178. The Initial Decision finds that the MWhs associated with grandfathered contracts that AMP-Ohio identified had not been properly removed from the lost revenue calculations and finds that the submitted corrections should be accepted.[200] The Initial Decision states that the imports of power by AMP-Ohio members from the New York Power Authority under a grandfathered transmission contract should not have been included in the SECA.[201] The Initial Decision also finds that MWhs associated with a grandfathered transaction with Ameren were incorrectly attributed to AEP and, accordingly, accepted the corrected sink code.

2. Brief on Exceptions

179. AMP-Ohio supports the Initial Decision's finding removing the MWhs associated with AMP-Ohio's grandfathered transmission contracts from the lost revenue calculations.

3. Commission Determination

180. We agree with the Initial Decision. The grandfathered agreements were incorrectly included in the lost revenue calculations, and we will require Midwest ISO TOs and the PJM transmission owners to submit revised compliance filings to reflect this adjustment, as applicable, in the compliance filings ordered below.

---

[200] Initial Decision, 116 FERC ¶ 63,030 at P 60.

[201] *Id.*

G. **Inclusion of Through-and-Out Revenues Associated with Affiliate Sales**

1. **Initial Decision**

181. In the compliance filings, transmission owners included revenues that they received from their merchant affiliates as lost revenues in their SECA calculations. The Initial Decision concludes that the inclusion of merchant affiliate transactions in the SECA calculation is unjust and unreasonable because it creates a financial windfall for the utility. The Initial Decision finds that treating merchant affiliate transactions as lost revenue is contrary to the Commission's finding that the SECA was not intended to provide greater revenues for the utility. The Initial Decision also states that the SECA is not intended to supplement the profits of a merchant affiliate. Therefore, the Initial Decision finds that affiliate transactions should be excluded from the lost revenues upon which the SECA is calculated, and the lost revenues in the compliance filings should be recalculated in accordance with this conclusion.[202]

182. The Initial Decision notes that Trial Staff argued that three conditions must be met before an affiliate transaction is included as lost revenues: (1) an independent load-serving entity is the ultimate source of the through-and-out payment; (2) elimination of the regional through-and-out rate causes the price to the merchant affiliate's load-serving entity customer to fall; and (3) imposition of the SECA with respect to the affiliate transaction at issue is revenue neutral for all parties. The Initial Decision notes that Trial Staff claims that, in general, the elimination of regional through-and-out rates is likely to cause a fall in prices that would justify the inclusion of affiliate transactions in the calculation of SECA charges.[203]

183. The Initial Decision finds that Trial Staff's claim that the elimination of regional through-and-out rates caused the price that load-serving entities paid to merchant affiliates to fall is incorrect. The Initial Decision rejects Trial Staff's analysis as not supported by any underlying evidence in the record. The Initial Decision also finds that Trial Staff's claim that there was more efficient dispatch as a result of the elimination of regional through-and-out rates does not support the inclusion of affiliate transactions as lost revenues for determining SECA charges. The Initial Decision also rejects Trial Staff's analysis because it is based solely on theoretical assumptions that have been disputed by the testimony of Mr. Zakem. The Initial Decision finds that the testimony of Mr. Zakem is entitled to significant weight because it is the only evidence in this case that attempted to quantify the assumptions presented or the price paid by load-serving

---

[202] *Id.* P 189.

[203] *Id.* P 153.

entities.[204] The Initial Decision finds that because Trial Staff's assumptions are not supported, the testimony of Mr. Pollock, Trial Staff's witness, is not entitled to significant weight.[205] The Initial Decision also finds that Dr. Henderson's testimony, which Trial Staff cites to support the conclusion that the elimination of regional through-and-out rates caused the price load-serving entities paid to affiliate generators to fall, is not entitled to significant weight. The Initial Decision finds that Mr. Zakem was a more credible witness on this issue and that Dr. Henderson's testimony was not consistent with Mr. Zakem's testimony or the record concerning affiliate transactions.[206]

184. The Initial Decision cites Mr. Zakem's testimony as showing that the elimination of regional through-and-out rates would not cause the prices that a load-serving entity pays to the merchant affiliate to fall. The Initial Decision also finds that there is no evidence demonstrating that a transmission component was used to determine the market price paid by customers to merchant affiliates, which could justify including merchant affiliate revenues in the SECA charges paid by these customers.[207] The Initial Decision finds that Mr. Zakem's testimony also provides evidence to support the claim that the prices load-serving entities paid to merchant affiliates fell is not consistent with market dynamics.[208] The Initial Decision therefore concludes that no party proved that the elimination of regional through-and-out rates caused the price to the merchant affiliate's load-serving entity customer to fall.[209]

185. The Initial Decision states that Trial Staff and AEP, Dayton, and Exelon criticize Mr. Zakem's study, but the Initial Decision notes that neither party offered any studies to contradict those of Mr. Zakem. AEP, Dayton, and Exelon do cite Dr. Henderson's rebuttal testimony for the proposition that the standard for lost revenue recovery has always been lost transmission revenues, not lost corporate profits. However, the Initial Decision finds that Dr. Henderson was not qualified as a legal expert, and thus, the Initial Decision does not give significant weight to his assertions concerning affiliate revenues.[210]

---

[204] *Id.* P 154.

[205] *Id.* P 165.

[206] *Id.* P 157 n.57, P 158 n.58.

[207] *Id.* P 154, 166.

[208] *Id.* P 155, 165.

[209] *Id.* P 166.

[210] *Id.* P 156 n.55, P 175.

186. The Initial Decision also finds that there is no record to support that including the merchant affiliate revenues in the companies' lost revenues satisfies the revenue neutrality requirement.[211] The Initial Decision finds that the focus of the inquiry on whether the inclusion of affiliate transactions in the SECA is revenue neutral should be how the entire corporation reflected the affiliate transactions, not what the affiliate charged the load-serving entity.[212] The Initial Decision states that, if transactions between affiliates did not result in net revenues, they should not be included as lost revenues in the calculation of the SECA.[213] The Initial Decision states that the inclusion of merchant function revenues would create a windfall for the affiliated transmission owner. By including as lost revenues transactions from its merchant affiliate, the transmission owner collects additional money from outside of the utility (in the form of the SECA), while its merchant affiliate merely no longer incurs an internal charge for transmission costs for through-and-out service. According to the Initial Decision, money formerly transferred from the left pocket to the right pocket within the utility is replaced by an equal amount of money coming into the utility from the outside – thus providing double recovery for the transmission owner and its affiliates.[214] The Initial Decision agrees with AMP-Ohio's assertion that the appropriate entity for the purpose of measuring revenue neutrality is the parent, not the subsidiary; thus, the replacement of an inter-affiliate regional through-and-out rate (which produces no revenue for the integrated company) with a SECA charge to a third party producing revenues, does not fulfill the requirement of revenue neutrality.[215]

187. The Initial Decision also finds that Trial Staff misplaces the burden of proof by assuming that affiliate transactions created revenues that should be included in the SECA obligations. The Initial Decision finds that the burden of proof should be on the proponents of the compliance filing to demonstrate that inter-affiliate transactions resulted in revenues that should be included as lost revenues in the calculation of the SECA.[216] The Initial Decision states that the transmission owners have the burden of proving that both their lost revenues and lost revenue calculations were just and reasonable. The Initial Decision notes that the Commission directed the RTOs and

[211] *Id.* P 161.

[212] *Id.* P 168.

[213] *Id.* P 167.

[214] *Id.* P 181 (*citing* Quest Initial Brief at 22-34).

[215] *Id.* P 173.

[216] *Id.* P 167.

transmission owners to provide supporting documents containing calculations and data, including North American Electric Reliability Corporation tag data used, and detailed narrative descriptions of all adjustments to data and calculations performed. However, the Initial Decision finds that there is no evidence demonstrating that affiliate transactions are properly recoverable as lost revenues for purposes of determining the SECA charges.[217]

188. The Initial Decision states that the expressed intent of the Commission in imposing the SECA is to provide for the reimbursement of lost revenues to an entity; there should be no inclusion of payments that the entity made to itself in the quantification of lost revenues. In other words, according to the Initial Decision, no SECA should be collected for, and turned over to, an entity that formerly paid itself a regional through-and-out rate that has now been eliminated.[218] The Initial Decision concludes, therefore, that inter-affiliate transactions should not be included in the lost revenues for the imposition of SECA obligations.[219]

189. In response to concerns about the impact that excluding affiliate transactions from the SECA would have on transmission owners' transmission revenue requirements, the Initial Decision states that, as the Commission found in previous orders, this case is not about the transmission owners' revenue requirements.[220] Although AEP provided testimony that the through-and-out revenues from affiliated transactions traditionally have been a significant factor in lowering transmission rates, the Initial Decision does not give AEP's testimony significant weight because this case does not involve AEP's revenue requirement or transmission rate.[221] The Initial Decision also finds that the record does not support the assertions made by FirstEnergy that native load customers will pay increased rates if affiliate transactions are not included in lost revenues. The Initial Decision acknowledges that through-and-out revenues result in credits against the transmission owner revenue requirements and thus reduce the costs borne by native load customers. However, the Initial Decision states that the record in this case shows that this does not refer to affiliate transactions. The Initial Decision also states that the

---

[217] *Id.* P 179 (*citing* June 2005 Order, 111 FERC ¶ 61,409 at P 37 n.12).

[218] *Id.* P 178.

[219] *Id.* P 187.

[220] *Id.* P 172 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 47, 49).

[221] *Id.* P 176.

Commission did not establish any mechanisms to impose transmission rate increases on native load customers if the SECA proponents calculated their revenues incorrectly.[222]

2. Briefs on Exceptions

190. AEP, Dayton, and Exelon, along with FirstEnergy, argue that the Commission identified specific adjustments that transmission owners had to make to the lost revenue calculations, but the Commission did not require or even consider in this proceeding any adjustments for revenues associated with affiliate transactions. AEP, Dayton, and Exelon argue, therefore, that the Initial Decision's removal of affiliate revenues from the SECA calculation was improper because the Commission did not set that issue for hearing. FirstEnergy states that, had the Commission intended for the exclusion of revenue associated with affiliate transactions from the calculation of lost through-and-out revenues, the Commission would have so provided.

191. AEP, Dayton, and Exelon also argue that the exclusion of affiliate revenues from lost revenue amounts violates the Commission's requirement that all transmission customers take service pursuant to open access transmission tariffs. AEP, Dayton, and Exelon argue that the Initial Decision, if adopted, would result in disparate treatment for affiliate transactions in that, unlike similar requests for transmission service by non-affiliates within the same period of time, the transmission owner will be unable to collect revenues lost due to the elimination of regional through-and-out rates through the SECA.

192. Similarly, FirstEnergy states that the Commission's well-established transmission policy requires a transmission provider to charge its merchant affiliate for transmission service just like all other customers. FirstEnergy states that the Commission consistently has required affiliates to reserve and pay for point-to-point transmission service under the applicable tariff even within the confines of a "corporate family." According to FirstEnergy, the Initial Decision makes this requirement meaningless by treating these as sham financial transactions. Clearly, FirstEnergy argues, the Commission's established transmission policies prohibit the "corporate family" approach and requires the rejection of this portion of the Initial Decision.

193. AEP, Dayton, and Exelon argue that the Initial Decision also disregards the Commission's standard of conduct regulations that require the separation of transmission and merchant functions by erroneously finding that the transmission owners did not actually lose any through-and-out revenues attributable to service provided to an affiliate. AEP, Dayton, and Exelon state that the merchant affiliate had to pay the transmission owner the regional through-and-out rate, and absent the Commission's eliminating the regional through-and-out rate, the transmission owner would still be receiving that

[222] *Id.* P 173.

revenue. They state that, pursuant to the Commission's regulations, the merchant affiliate accounted for the payment to the transmission owner as an expense that reduced its income in a set of books and records separate and distinct from those of the transmission owner. The through-and-out revenue attributable to an affiliate transaction was recorded as transmission revenue by the transmission owner, and its elimination creates a loss of revenue for the transmission owner. According to AEP, Dayton, and Exelon, the Commission's standard for lost revenue recovery has always been lost transmission revenues, not lost corporate profits. The Initial Decision thus errs in focusing on the revenues of a corporation as a whole rather than addressing the lost through-and-out revenues of each separately-functioning entity.

194. AEP, Dayton, and Exelon also argue that, by eliminating merchant transactions from lost revenues, the Initial Decision creates a disparate treatment of similarly-situated affiliated generators and non-affiliated generators. According to AEP, Dayton, and Exelon, this is unduly discriminatory and thus violates the FPA. In addition, they maintain that a requirement for transmission owners to show that the elimination of regional through-and-out rates caused the price to the merchant affiliate's load-serving entity customer to fall is a burden not imposed on non-affiliated generators and is, thus, unduly discriminatory. AEP, Dayton, and Exelon point out that the Commission recognized that generators might benefit to some extent due to the elimination of regional through-and-out rates without passing the savings on to the load-serving entities but noted that this concern was mitigated by several factors, including load-serving entities' ability to access generation anywhere in the combined region for a single access charge. They add that the Commission also found that the elimination of the regional through-and-out rates will result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation as well as imports.[223]

195. Trial Staff argues that the Initial Decision incorrectly finds that affiliate revenues should not be included in determining lost through-and-out revenues. Trial Staff states that the basis for this finding is the incorrect determination that there was no record evidence to show that the elimination of regional through-and-out rates resulted in a decrease in market prices to load-serving entities. Trial Staff avers that, if there was no expectation that market prices faced by load-serving entities would decrease as a result of the elimination of regional through-and-out rates, there would have been no reason to eliminate regional through-and-out rates in the first place. Trial Staff states that the Commission eliminated regional through-and-out rates because they had a distortive effect on the market, finding that the elimination of regional through-and-out rates will

---

[223] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 32 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation as well as imports in eliminating the regional through-and-out rates.

196. According to Trial Staff, there is no reason why that economic fact is any less applicable where affiliates are involved. Trial Staff argues that even affiliated entities that sold across a seam would be more competitive once the regional through-and-out rate is eliminated because they would no longer have to include the regional through-and-out rate in their price for delivered power. Their cost of providing the service declines, whether that cost was passed on to the load-serving entity as an additive charge or was merely a factor in determining underlying prices. Trial Staff states that the Commission instituted the SECA to compensate transmission entities for this lost revenue, and there is no reason why affiliated transmission companies in the first instance should be denied the recovery of their lost revenues.

197. Trial Staff argues that the Initial Decision appears to have accepted the notion that the affiliated marketers and transmission companies colluded among themselves to not reduce prices to load-serving entities or to reduce the commodity price to preserve the prices of the affiliated transmission provider. According to Trial Staff, such a concern is without merit. Trial Staff argues that there has been no showing, or even a direct allegation, that this conduct actually happened. Trial Staff states that the transmission affiliates at issue here are not mere internal departments but rather, pursuant to Commission regulations, must be stand-alone entities. They should be treated as such in determining whether they are entitled to the recovery of lost revenues. Therefore, Trial Staff argues, the Commission should conclude on the record in this case that affiliated entities lost revenue when regional through-and-out rates were eliminated.

198. Trial Staff also argues that testimony at the hearing that purports to show that prices for load-serving entities did not decrease is based on a sampling period that is too short to be meaningful for any purpose and should not be a basis for a decision of this magnitude. Trial Staff states that revenues from affiliate transactions should generally be included in the development of the SECA but agrees that load-serving entities should not have to pay any portion of through-and-out revenues that were not actually lost. If the Commission finds it necessary, Trial Staff states that parties (transmission owners or load-serving entities) should be given the opportunity to demonstrate in the next compliance stage of this proceeding whether the affiliate entities lost revenue due to the elimination of regional through-and-out rates.

199. AEP, Dayton, and Exelon state that another reason to overturn the decision to exclude affiliate transactions is because that decision flouts the Commission's ratemaking policies requiring transmission owners to credit all revenues received from regional through-and-out rates for transmission service provided over their systems against zonal transmission revenue requirements and rates. AEP, Dayton, and Exelon state that the

Initial Decision recognizes that through-and-out revenues result in credits against transmission owner revenue requirements and, thus, reduce costs borne by native load customers, but then, without reference to any evidence, and in contradiction of the Commission's requirements that all transmission service be treated comparably, whether affiliate or not, the Initial Decision states that the record shows that the credit does not refer to affiliate transactions.[224]

200. FirstEnergy claims that, if the SECA charge collected from each importing load-serving entity were reduced (such as will occur if the revenue associated with affiliate transactions is excluded), the unrecovered costs would be paid by the transmission owner's native load. This, in turn, will cause the transmission owner's native load to pay increased rates. According to FirstEnergy, this cost shift would contravene the Commission's stated purpose for the SECA, which was to establish a lost revenue recovery mechanism to mitigate cost shifting and to hold transmission owners revenue neutral during a transition period.

201. In its stand-alone Brief on Exceptions to the Initial Decision, Exelon requests that, if the Commission does not reverse the Initial Decision's finding on this issue in its entirety, the Commission should clarify that, in instances where the transmission owner and its affiliated merchant are separate corporate entities, there will be no reduction to the transmission owner's lost revenues for through-and-out service provided to the affiliated merchant.[225]

202. Exelon argues that, without this clarification, the Initial Decision would result in an unjustifiable commingling of the businesses of the separate corporations through which Exelon conducts its jurisdictional affairs. Exelon argues that the Initial Decision's erroneous finding results from a fundamental failure to recognize the separate legal identities of and distinct operational functions performed by ComEd, PECO, and Exelon Generation Company, LLC (ExGen). Exelon argues that the regional through-and-out rates ExGen paid to ComEd and PECO (via PJM) represent real revenues, not mere accounting records on the books. This is revenue that ComEd and PECO enjoyed until the elimination of regional through-and-out rates, and therefore, no financial windfall would result from the inclusion of dollars for legitimate through-and-out transactions in ComEd and PECO's lost revenue calculations. Exelon states that it is completely appropriate to include revenue from ExGen as part of PECO or ComEd's through-and-

---

[224] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 173 n.63).

[225] Exelon states that it incorporates by reference the AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision.

out revenues, as the Commission's standard for lost revenue recovery has always been lost transmission revenues, not lost corporate profits.

203. Another clarification should be made, according to FirstEnergy, if the Commission requires affiliate transactions to be excluded. Although FirstEnergy strongly believes that there is no basis to exclude revenue associated with affiliate transactions, should the Commission nonetheless require it, the Commission must require a corollary adjustment for each zone's SECA obligation to ensure that no affiliate of a transmission owner is responsible for paying a SECA associated with the affiliate transactions. FirstEnergy states that the need for that adjustment is based on unrebutted testimony. Furthermore, FirstEnergy believes that the Initial Decision creates one exception, applicable to FirstEnergy, to the finding that affiliate transactions should be excluded from the SECA calculations.

204. Midwest ISO TOs state that they do not seek, as a group, exception or otherwise state a position on the finding in the Initial Decision that all transmission owners should have excluded affiliate transactions from the calculation of their lost revenues. However, they seek clarification that the exclusion of affiliate transactions does not apply to any Midwest ISO transmission owner if and when that Midwest ISO transmission owner became a Midwest ISO member during the test period. Midwest ISO TOs claim that, for transmission owners that joined Midwest ISO during the test period, there were, by definition, no merchant affiliate transactions once the transmission owner was no longer the transmission provider. After the transmission owner joined Midwest ISO, it or its affiliate contracted with Midwest ISO for transmission service. At that point, according to Midwest ISO TOs, the transmission service was provided over the Midwest ISO transmission system, of which the transmission owner's facilities only represent a part. Further, transmission revenues are credited under the Midwest ISO formula rate (thereby limiting any arguments as to windfalls) and under the Midwest ISO revenue distribution method (there typically would not be a flow through to the transmission owner of the revenues that its marketing arm would pay Midwest ISO).

3. **Briefs Opposing Exceptions**

205. In response to the argument that the Commission in prior orders did not require the exclusion of affiliate revenues, Green Mountain states that the Commission found that the SECA compliance filings may be unjust and unreasonable and set them for hearing to make that determination. Green Mountain argues that a finding, after the hearing, that the filings were indeed unjust and unreasonable cannot be said to violate the Commission's orders. In addition, Green Mountain argues that the Commission found that, since it did not have actual rates before it, the Commission would still need to evaluate the resulting SECA rates to ensure that the mechanism produces a reasonable result.

206. Quest, Strategic, and WPS Energy, Dominion, and AMP-Ohio also dispute AEP, Dayton, and Exelon's claim that the exclusion of merchant affiliate revenues from the SECA violates the Commission's orders in this proceeding. Dominion states that AEP, Dayton, and Exelon do not point to any specific language in any order that makes such a finding. Dominion and Quest, Strategic, and WPS Energy note that the Commission held that the SECA was intended to hold transmission owners revenue neutral, not to provide them with greater revenues. Quest, Strategic, and WPS Energy and AMP-Ohio claim that they (and other parties) showed that that through-and-out revenues formerly associated with affiliate transactions were never lost so they were never includable as lost revenues. They conclude that there was, thus, no need for the Commission to include in its orders a particular exclusion for affiliate transactions.

207. Green Mountain, Dominion, and Quest, Strategic, and WPS Energy dispute AEP, Dayton, and Exelon's claim that excluding merchant affiliate transactions from the SECA violates the Commission's open access requirements. Green Mountain and Quest, Strategic, and WPS Energy agree that all entities must use the Open Access Same-Time Information System to reserve transmission and note that nothing in the Initial Decision would require that affiliate transactions be treated outside of the requirements of the approved tariffs of the two RTOs. The issue of access to and reservation of transmission, according to Quest, Strategic, and WPS Energy, is wholly separate from the intra-corporate accounting of the transaction. Green Mountain argues that nothing in the PJM or Midwest ISO tariff, or any Commission rule, requires that the Commission ignore the fact that a dollar received by the transmission owner from an unaffiliated customer represents a net gain of a dollar to the overall corporate entity and its shareholders, but a dollar received by the transmission owner from an affiliate represents a wash. Dominion argues that, because the SECA is a load-based charge that is the same regardless of the supplier, the inclusion or exclusion of transmission revenues from merchant affiliates does not result in any transmission provider giving preference to its merchant affiliate.

208. Dominion, AMP-Ohio, and BG&E argue that excluding merchant affiliate transactions from the SECA does not contravene Commission regulations requiring the separation of transmission and merchant functions. Dominion states that the Commission's rules and policies do not require – in any direct or indirect manner – that transmission revenues from merchant affiliates be included in the SECA. AMP-Ohio states that the primary weakness in citing the separation of functions is that it simply does not apply to this situation. AMP-Ohio argues that, although at one time and for good reason, the Commission required the marketing arm of an electric conglomerate to "pay" its affiliate for transmission, that decision does not indicate whether a transmission-owning utility has actually lost money when regional through-and-out rates were eliminated. Dominion adds that excluding merchant affiliate transmission revenues from the SECA does not cause a transmission owner to cease operating separately from its merchant affiliates. Similarly, BG&E argues that the fact that there are no lost revenues

to a corporation when intra-company transfers are ceased does not implicate the Commission's affiliate conduct rules.

209. Green Mountain believes that the argument regarding Commission regulations requiring the separation of transmission and merchant functions is a red herring. The regulations in question impose a variety of requirements upon the transmission owners themselves, and upon their affiliates, but Green Mountain argues that no Commission regulation requires that transition revenues be calculated as though affiliates were entirely unrelated entities. Green Mountain argues that the reason that the Commission has found it necessary to regulate relations among transmission and merchant affiliates under the same corporate umbrella is precisely because the transmission employees know that, except to the extent that such regulations require otherwise, their obligation to maximize shareholder value will lead them to treat employees of the merchant function as co-workers and not as representatives of an entirely-separate business. The Initial Decision is, thus, entirely consistent with Commission regulations requiring the separation of the transmission and marketing functions.

210. Dominion disputes AEP, Dayton, and Exelon's assertion that eliminating merchant affiliate transactions from the SECA would unduly discriminate between affiliated generators and non-affiliated generators. Dominion argues that the magnitude of SECA charges are a matter of concern to loads, and not to generators, since SECA charges are paid by loads and not by generators. Affiliated and non-affiliated generators, according to Dominion, should therefore be indifferent to how such charges are calculated and what specific items are included in the calculation of such charges. In addition, Dominion argues that excluding transmission revenues from merchant affiliates from the SECA assures that any merchant affiliate that had unnecessarily reserved transmission capacity to inflate the through-and-out revenues of its parent would not be rewarded by having such revenues included in the SECA. Dominion claims that a merchant affiliate in 2002 and 2003 (a time period when the SECA and similar transitional mechanisms were well-known) would have had a perverse incentive to reserve excess transmission capacity from its parent, even if it did not need or use it, if it thought that the parent might be able to use these associated revenues as a means of inflating future SECA revenues. Dominion argues that excluding transmission revenues from merchant affiliates from the SECA would ensure that any such contravening behavior is not rewarded.

211. Constellation argues that both affiliated and non-affiliated generators enjoy the benefits of the elimination of regional through-and-out rates. That AEP utilized inter-departmental adjustments to account for its transactions, according to Constellation, has nothing to do with any burden on the affiliated generator. Green Mountain argues that discrimination is undue only if the entities treated differently are similarly situated. That is not the case here, according to Green Mountain, where the Initial Decision properly treats affiliate transactions differently because the economic effects of such transactions

are different. Similarly, AMP-Ohio argues that this "discrimination" hardly seems undue because only affiliated generators pay themselves.

212. Dominion disagrees with Trial Staff's assertion that eliminating merchant affiliate transactions from the SECA is contrary to the Commission's finding in a prior order that the elimination of regional through-and-out rates will result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation as well as imports. Dominion argues that Trial Staff assumes that this finding would equally apply whether the payment being eliminated is truly a variable cost paid by a non-affiliate to a transmission provider or whether – as in the case of AEP – it is an expense booked by its merchant affiliate that is offset by revenue booked by the parent. Dominion argues that, since Trial Staff ignores this economic distinction, its arguments conflating non-affiliate and affiliate transactions must be rejected. Dominion also argues that no transmission owner has shown that the customers of a merchant affiliate benefited due to the elimination of regional through-and-out rates through reduced prices. Dominion states that the example that AEP provides in its Brief on Exceptions to the Initial Decision is grossly oversimplified and, as written, obscures facts and is ultimately worthless.

213. Dominion also states that a merchant affiliate's payments to an affiliated transmission owner has no effect on the overall profits of the combined enterprise and is not a relevant factor to consider in the determination of the price charged to a load-serving entity. In addition, Dominion argues that no party has demonstrated that any market price charged by a merchant affiliate included an identified transmission component charged to any transmission owner's merchant affiliate, much less used to determine the market price paid by those customers that would justify the inclusion of such merchant affiliate transmission revenues in SECA charges. Dominion states that the Initial Decision correctly notes that neither Trial Staff nor any other party has provided a study or analysis that supports the assertion that the costs of merchant affiliate transmission are included in the sale prices paid by the ultimate customers of merchant affiliates.

214. Similarly, Quest, Strategic, and WPS Energy argue that Trial Staff, without evidence to support its position, relies on the general statement in Commission orders to the effect that the elimination of the SECA should make more remote generation economic for import. They state that it has shown that the elimination of regional through-and-out rates removes both the expense item for the generator and the revenue item for the transmission owner, resulting in no loss of revenue. Quest, Strategic, and WPS Energy argue that, in order to conclude that the elimination of the regional through-and-out rate paid by an affiliate would cause a reduction in costs for a utility and a resultant decrease in market prices, one must also conclude that the Commission's action in Order No. 888, which resulted in the transmission provider charging the merchant

affiliate in the same way that it charged non-affiliates, caused an increase in costs for a utility and a resultant increase in market prices. They argue that common regulatory mechanisms, such as inter-departmental adjustments, result in no change to revenue requirements or net earnings, illustrating that neither Order No. 888 nor the elimination of regional through-and-out rates affects a utility's costs attributable to internal charges by one affiliate to another. Quest, Strategic, and WPS Energy also argue that Mr. Zakem showed in his testimony that the market price for energy is closely tied to the costs of competing power in the RTO area and is not directly proportional to reductions in the cost of importing power across the seam.

215. BG&E argues also that it is a contradiction to speak of lost revenue associated with affiliate transactions because, for example, AEP suffered no loss when one subsidiary was spared an expense equal to another subsidiary's revenue. BG&E also states that it does not see how any relationship between the elimination of the regional through-and-out rate and revenues AEP received from its load-serving entities can be traced. In addition, BG&E argues that, since AEP has only one parent with publicly-traded stock, there was no net increase in income to AEP stockholders from the transmission component of affiliated transactions. If a non-affiliate of AEP were required to make SECA payments to AEP to replace the through-and-out payments previously made by an AEP affiliate, this would constitute unjust enrichment to AEP rather than compensation for lost revenue. BG&E argues that the inclusion of AEP intra-corporate through-and-out payments to the SECA dollars would increase AEP's lost revenue by approximately $88 million. According to BG&E, that amount would represent new net earnings for AEP at the expense of non-native load customer rate zones and, in part, of the stockholders of competitor transmission owner companies, some of whom have no recourse under state settlements to pass on the payments in retail rates.

216. AMP-Ohio claims that AEP, Dayton, and Exelon's insistence that the focus should be on lost revenues, not lost profits, is effectively an admission that there were typically no losses when regional through-and-out rates were no longer charged to affiliates. In that case, according the AMP-Ohio, the inclusion of these payments in lost revenues as a matter of definition would increase the combined entities' profit, adding unduly to the already substantial SECA burden on load-serving entities and their customers.

217. Green Mountain disputes Exelon's claim that, regardless of its overall treatment of the issue of affiliate transactions, the Commission should permit the inclusion of affiliate revenues in the calculation of lost revenues where the transmission owner and its affiliate merchant are separate corporate entities. Green Mountain argues that nothing in Exelon's brief shows that Exelon's affiliate transactions resulted in net revenues, regardless of the corporate form chosen by Exelon.

218. Likewise, Constellation argues that, on the corporate level, allowing affiliate transactions to be included in the SECA would guarantee a windfall to shareholders through the payment of SECA charges by unaffiliated load-serving entities to cover

regional through-and-out rates that previously resulted in no net revenue to the corporate parent. Because this result, according to Constellation, contravenes cost-causation principles, refusal to allow transmission owners to collect affiliate-related revenues is completely warranted.

219. Dominion states that the claim that transmission revenues from merchant affiliates generally should be included in the calculation of a transmission owner's lost revenues without specific evidentiary support turns the burden of proof on its head. Dominion argues that, as the proponents of the SECA, each transmission owner making the compliance filing ordered by the Commission had the burden of proof at the hearing to justify its proposed rate change. In this case, Dominion contends that the Initial Decision properly concludes that the proponents of including transmission revenues from merchant affiliates as lost revenues do not meet this standard because they fail to demonstrate that such revenues are in fact "lost."

220. Quest, Strategic, and WPS Energy argue that the finding in the Initial Decision to eliminate intra-corporate transfer payments by merchant affiliates is not novel or without precedent. They state that it has been shown beyond argument that there are not actual or out-of-pocket costs incurred for the corporate entity when a merchant affiliate pays transmission charges to a transmission affiliate. They claim that the uncontroverted evidence detailing the intra-corporate accounting for transfer prices within AEP shows that revenue for the transmission department is offset by an expense to the merchant department, and the transaction has zero effect on corporate earnings. As such, according to Quest, Strategic, and WPS Energy, excluding affiliate revenues from the SECA is consistent with Commission precedent that permits affiliated generators to recover only actual costs to the corporate entity of transactions with its affiliates, not market prices, indexed prices, or opportunity costs.[226]

221. Dominion disputes Trial Staff's claim that the Initial Decision (and parties including Dominion) accepted the notion that the affiliated marketers and transmission companies colluded among themselves to not reduce prices to load-serving entities or to reduce the commodity price to preserve the prices of the affiliated transmission provider. Dominion states that Trial Staff misreads the basis in the Initial Decision for eliminating merchant affiliate transactions from the SECA. Dominion argues that the nature of the overall corporate enterprise and the rational decision drivers associated with the merchant affiliate's market sales activities would be expected to keep any "paper" transmission payments to its affiliate out of the decision-making process for any sales by the merchant

---

[226] Quest, Strategic, and WPS Energy Brief Opposing Exceptions to the Initial Decision at 20-21, (*citing San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services Into Markets Operated by the California Indep. Sys. Operator and the California Power Exchange Corp.*, 114 FERC ¶ 61,070 (2006)).

affiliate. According to Dominion, this decision-making process by the merchant affiliate would be engaged in independently of – and not in concert with – its transmission owner affiliate. Dominion claims that a merchant affiliate's consideration of enterprise-wide financial impacts is not prohibited by Commission rules or tariff requirements. Dominion adds that such behavior is in no way evidence of collusion. Dominion also argues that Trial Staff offered no explanation as to how a transmission owner and its merchant affiliate could possibly collude to increase prices to third-party load-serving entities.

222. Quest, Strategic, and WPS Energy call outlandish Trial Staff's claim that parties, including Quest, appear to have accepted the notion that the affiliated marketers and transmission companies colluded among themselves to not reduce prices to load-serving entities or to reduce the commodity price to preserve the prices of the affiliated transmission provider. Quest, Strategic, and WPS Energy state that neither the parties nor the Initial Decision have implied or stated such an accusation. They state that they did provide evidence that Trial Staff witness Mr. Pollock's assumption that the market price on one side of the Midwest ISO-PJM seam will change by an amount equal to the reduction in transmission costs of suppliers on the other side of the seam is incorrect. Quest, Strategic, and WPS Energy point out the deficiencies in Mr. Pollock's understanding of market dynamics (which Mr. Zakem explained is his Cross-Answering Testimony). They state that Mr. Zakem's testimony showed that most of the savings due to the elimination of regional through-and-out rates likely were captured by merchants, which is what one would expect from knowledge of how merchants set prices in the face of competition. Collusion is not necessary, they claim, nor was it ever alleged.

223. AMP-Ohio states that it strenuously disagrees with Trial Staff's presumption that the inclusion of affiliate transactions will not lead to additional revenue recovery. AMP-Ohio argues that Trial Staff's premise that every sale to a load-serving entity included an embedded transmission component is unsupported by any record evidence and contrary to the only record evidence on the subject. Although Trial Staff argues that Mr. Zakem's evidence should be disregarded because his sample was too small, AMP-Ohio notes that the Initial Decision finds that Mr. Zakem's testimony is the only quantified testimony on the record concerning this point and is given substantial weight. AMP-Ohio argues that it appears that, when choosing between two positions, one of which is supported by some quantitative evidence and the other of which is supported by no quantitative evidence, Trial Staff adopts the latter.

224. In response to AEP's claim that it reduced its transmission rates based on the SECA revenue that AEP expected to receive, Dominion states that evidence shows that AEP provided such SECA revenue credits during only five of the sixteen months that the SECA was in effect. Dominion also notes that AEP itself is the largest load-serving entity taking transmission service under the PJM tariff in the AEP zone. Dominion also argues that the record indicates that the overall percentage of SECA revenues credited

back to entities not affiliated with AEP is likely to be a small percentage of AEP's total SECA revenues. Dominion also states that itself, Dayton, and most other transmission owners in PJM do not have similar SECA crediting provisions. In addition, Dominion argues that nowhere in the record is there any evidence of the amount of relief that AEP's SECA credits actually provided to its native load customers. Dominion also claims that AEP's explanation of the SECA credit that it applies to reduce transmission rates is incomplete because AEP does not discuss whether any such credit actually provided to AEP's native load customers was equally offset by the expense associated with its merchant affiliate's transmission reservation.

225. Quest, Strategic, and WPS Energy argue that whether and how affiliate revenues are credited to the transmission owner's cost of service is irrelevant to whether affiliate revenues are lost for the purposes of the SECA. They contend that AEP has never submitted evidence to show that excluding affiliate revenues from the SECA will result in lower revenue credits to their customers. In addition, Quest, Strategic, and WPS Energy assert that eliminating a revenue credit to transmission customers does not create a loss to AEP. For its part, Constellation acknowledges that, in the typical cost-of-service ratemaking process, whether payment is received from affiliates or non-affiliates does not make a difference. In the context of this proceeding, however, Constellation argues that blind allegiance to that policy would not result in revenue neutrality.

226. Regarding FirstEnergy's claim that it is exempt from having to exclude affiliate transactions from the SECA calculations, AEP, Dayton, and Exelon argue that the Initial Decision makes no such exception for FirstEnergy. Regarding FirstEnergy's claim that the elimination of inter-affiliate payments from the SECA would require an adjustment to everyone's SECA, AMP-Ohio argues that the FirstEnergy testimony on this issue may be unrebutted, but that could only be because the "testimony is no more comprehensible than the FirstEnergy argument that relies on it."[227]

227. AEP, Dayton, and Exelon oppose Midwest ISO TOs' request that the Commission clarify that the finding that affiliate transactions must be excluded does not apply to a transmission owner for that portion of the test period that it was in an RTO. AEP, Dayton, and Exelon argue that, while the Initial Decision errs in excluding affiliate transactions, there is no basis for distinguishing the situation of a transmission owner that was in an RTO during the test period from the situation of a transmission owner that was not. In particular, they claim that, while Midwest ISO TOs argue that there were, by definition, no merchant affiliate transactions once the transmission owner was no longer the transmission provider, the Initial Decision's findings are based on whether a particular transmission customer that paid regional through-and-out rates was affiliated

[227] AMP-Ohio Brief Opposing Exceptions to the Initial Decision at 28.

with a transmission owner that has included the revenues associated with regional through-and-out rates paid by the affiliate in its lost revenue claim.

4. **Commission Determination**

228. We find that the Initial Decision's finding that affiliate transactions should be excluded from the SECA calculation is incorrect. The revenue that a transmission owner receives from an affiliate for through-and-out transmission service is recorded as revenue for the transmission owner, just as if that revenue came from an unaffiliated entity. That the method by which a transmission provider receives revenue from its affiliate is through intra-corporate accounting does not alter the fact that the transmission provider records less revenue if an affiliate does not pay its affiliated transmission owner the regional through-and-out rate. In addition, the Initial Decision's finding that affiliate revenues should be excluded from the SECA is flawed, as a general matter, because it would require the Commission to consider the revenue that a utility receives from *power* sales to determine whether the rate that the transmission owner charges for *transmission* service is just and reasonable. Therefore, we find that the revenue that a transmission provider previously received from an affiliate should be included in the lost revenue calculation for the SECA.

229. By excluding affiliate transaction revenues from the SECA, the Initial Decision is trying to address the possibility that generators may not pass on the savings due to the elimination of regional through-and-out rates to load-serving entities. However, the Commission already recognized that generators may benefit to some extent due to the elimination of regional through-and-out rates and that those savings may not all be passed on to load-serving entities. The Commission found that this concern, which we note is the same whether a generator is affiliated with the transmission owner or not, is mitigated for several reasons. Among other things, customers serving load in the combined region will be able to reserve service from the point where power is injected into the combined region to the ultimate delivery point from which load is served for a single non-pancaked charge, thus enabling load-serving entities to negotiate power supply contracts based on the market price where the resource is located, rather than where the load is located, without incurring additional access charges. In addition, the elimination of regional through-and-out rates will result in more remote generation becoming economic for import, which will put downward pressure on market prices where load is located, resulting in lower costs for purchases from local generation as well as imports.[228]

230. We understand that there may not be a perfect one-for-one correlation during the transition period between the reduction in prices load-serving entities pay for energy and the savings that a generator realizes by not having to pay regional through-and-out rates.

---

[228] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45.

However, we agree with Trial Staff that Mr. Zakem's data showing that the elimination of regional through-and-out rates did not result in any lower prices is too limited to be meaningful given the potential effects of weather, possible generation outages, and fuel cost variation during the short sample period.[229] The Initial Decision does not dispute that Mr. Zakem's sample size was small, but it finds that, since Mr. Zakem's testimony is the only testimony that attempted to quantify any price changes, it should be given substantial weight. However, as we note above, the Commission already found that the elimination of regional through-and-out rates will put downward pressure on market prices. The Commission did not impose as a condition to recovery of lost revenues through the SECA a requirement that transmission owners prove that prices, in fact, went down as a result of the elimination of regional through-and-out rates. In sum, we find that Mr. Zakem's testimony is not a sufficient basis to conclude that, notwithstanding the downward pressure on prices caused by the elimination of regional through-and-out rates, the power rates that generators charged during the entire transition period did not go down.

231. The Initial Decision also errs by concluding that a transmission owner's revenues are not affected by the loss of revenue from regional through-and-out rates paid by an affiliate.[230] The Initial Decision makes this error by treating the revenue that a transmission owner receives for transmission service as equivalent to the revenue that the transmission owner's affiliated generators receive for power sales. As the Commission previously explained, however, the revenues that a transmission owner receives from regional through-and-out rates are credited against the transmission owner's revenue requirement and relieve native load customers of their responsibility for a portion of the transmission owner's cost of service in the transmission rates charged them by the transmission owner.[231] In contrast, revenue that the transmission owner's affiliated generator receives for power sales is not considered in the calculation of the transmission rate. The Initial Decision acknowledges this difference but then finds, incorrectly, that the record shows that the Commission's statement about credits for through-and-out revenues does not refer to affiliate transactions.[232] The Initial Decision does not cite to any evidence in the record that shows that the credit for through-and-out revenues does not include affiliate transactions. In fact, the Initial Decision notes that AEP testified that the through-and-out revenues from affiliate transactions traditionally have been a significant factor in lowering transmission rates because approximately one-half of the

[229] Initial Decision, 116 FERC ¶ 63,030 at P 156 n.55.

[230] *Id.* P 183.

[231] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 19 n.36.

[232] Initial Decision, 116 FERC ¶ 63,030 at P 173 n.63

point-to-point revenue credits against the cost of service in AEP's last rate case were affiliate transactions.[233]

232. The Initial Decision does not give significant weight to AEP's evidence showing that the credit for through-and-out revenues includes affiliate transactions because, according to the Initial Decision, the Commission found in a prior order that this case does not involve AEP's revenue requirement or transmission rate.[234] We disagree with that assessment. What the Commission stated in the language cited by the Initial Decision was that it had previously accepted the transmission owners' existing cost-of-service and revenue levels as just and reasonable and that the Commission's actions in this proceeding will maintain, not change, the level of these revenues.[235] The Commission also found that, based on the record in the proceeding, it had no reason to believe that the transmission owners' existing rates or revenues are unjust and unreasonable and, therefore, did not require Midwest ISO and PJM to submit updated cost-of-service studies in their compliance filings.[236] It is not inconsistent with those findings to recognize that the revenue that a transmission owner receives from its affiliated generators through regional through-and-out rates was considered as a credit that reduced the existing transmission rates. In fact, by prohibiting affiliate revenues from being included in the SECA calculations, it is the Initial Decision that effectively would require an adjustment to be made to the transmission owners' existing rates and revenues, which is inconsistent with the Commission's previous findings.

233. Since the parties that support the exclusion of affiliate revenues from the SECA are advocating an adjustment to the existing cost-of-service and revenue levels of the transmission owners, the burden is on those parties to demonstrate that the adjustment is just and reasonable. Even if it were appropriate under these unusual circumstances to consider the impact of generator revenues on transmission revenues, the basis for excluding affiliate transactions from the SECA is a finding that affiliated generators received the same amount of revenue during the transition period as they did during the test period. The only support for this finding, however, is the testimony of Mr. Zakem, which, as we note above, is based on a very small sample of prices during the transition period. We also note that the Initial Decision relies on Mr. Zakem's conclusions, not because his conclusions are well supported, but simply because his is the only quantified

---

[233] *Id.* P 176.

[234] Initial Decision, 116 FERC ¶ 63,030 at P 172, 176 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 47, 49).

[235] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 47.

[236] *Id.* P 49.

testimony on the record about prices during the transition period.[237] However, transmission owners did not necessarily have to submit studies to show that the prices that their affiliated generators charged during the transition period went down because transmission owners are not advocating an adjustment to their existing revenue levels. Accordingly, we find that the record does not support a finding that affiliate transactions should be excluded from the SECA calculations.

234. Furthermore, the Initial Decision does not support imposing a requirement for affiliated generators to show that prices went down but not imposing the same requirement for unaffiliated generators. It is possible that an affiliated generator (and its corporate parent) had an increase in profits during the transition period that may be attributable in part to the elimination of regional through-and-out rates, but that is also possible for an unaffiliated generator (and its corporate parent). There is no evidence in the record that affiliated generators were in a better position during the transition period to resist downward price pressure caused by the elimination of regional through-and-out rates than were unaffiliated generators. Thus, it is the Initial Decision that arguably unduly discriminates – against affiliated generators, by imposing on only them a requirement to show that they passed the savings associated with the elimination of regional through-and-out rates to the affiliated transmission providers.

H. Inclusion of PJM Non-Firm Point-to-Point Transmission Service Revenues

1. Initial Decision

235. The Initial Decision finds that lost revenues for non-firm point-to-point transmission service should be included as lost revenues and should continue to be credited to transmission customers as is provided for under section 27A of PJM's tariff.[238] The Initial Decision states that all parties agreed with this position and that the revenue crediting would benefit customers.

2. Commission Determination

236. We agree with the Initial Decision. The lost revenues for non-firm point-to-point transmission service are to be included as lost revenues, as reflected in the PJM transmission owners' lost revenue calculations.

---

[237] Initial Decision, 116 FERC ¶ 63,030 at P 156 n.55.

[238] *Id.* P 190.

I. Zonal and Subzonal Allocations

237. In the July 2003 Order, the Commission stated that it would allow SECA charges on a subzonal basis, since subzonal charges best align the benefits of eliminating rate pancaking with the associated lost revenues. The Commission also stated that, if transactions cannot be traced to load in various zones of the Classic PJM region because of operation of the PJM spot market, Classic PJM TOs should address alternative methodologies for evaluating the relative benefits from import transactions between the various zones of the Classic PJM region.[239]

238. In the November 2003 Rehearing Order, the Commission affirmed its decision to allow the SECA to be charged on a subzonal basis. The Commission found that, by permitting the SECA to be charged on a subzonal basis, the benefits of eliminating rate pancaking are more closely aligned with the associated lost revenues so that load will not be significantly burdened by the transition to a common market.[240]

239. However, the Commission noted that some parties believe that the determination of SECA charges by subzones is difficult to administer. The Commission stated, therefore, that it would accept calculation of the SECA on a subzonal basis, unless all of the subzones within a zone agree otherwise (i.e., agree to charge on a zonal basis). The Commission directed Midwest ISO and PJM to consult with the customers in the other RTO as to whether they want their SECA calculated on a subzonal or zonal basis. The Commission ordered that, if the parties in the zone agree that they want their SECA charges calculated on a zonal basis, Midwest ISO and PJM should submit their data on a zonal basis. Otherwise, the Commission stated, Midwest ISO and PJM should provide the data on a subzonal basis.[241]

1. Initial Decision

240. The Initial Decision finds that the record as developed does not support a finding that use of subzones produces just and reasonable results. The Initial Decision finds that the compliance filings' use of subzones in New PJM but not in Classic PJM creates unjust and preferential results between Classic PJM and New PJM.[242] The Initial Decision states that, because the North American Electric Reliability Corporation tag data

---

[239] July 2003 Order, 104 FERC ¶ 61,105 at P 54.

[240] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 85.

[241] *Id.* P 86-87.

[242] Initial Decision, 116 FERC ¶ 63,030 at P 311.

cannot identify specific sinks within Classic PJM, the SECA within Classic PJM was not allocated on a subzonal basis.[243] The Initial Decision notes that instead the SECA obligations for entities in the Classic PJM region are based on load-ratio share without regard to each load-serving entity's use of the other RTO's system.[244] The Initial Decision concludes that, because subzones could not be created in Classic PJM, the allocation in Classic PJM does not comply with cost-causation principles.[245]

241. In addition, the Initial Decision finds that the record demonstrates that all of the proposed subzonal cost allocation filings fail to properly allocate charges consistent with cost causation and benefit derivation. The Initial Decision finds that, as a result, the filings do not comply with Commission precedent.[246]

242. As further evidence that the subzonal allocations were not done in compliance with cost-causation principles, the Initial Decision cites AEP witness Mr. Bethel, who stated that he did not take into consideration the benefits that any particular subzone would expect to receive due to the elimination of regional through-and-out rates. The Initial Decision also cites Dr. Henderson, who stated that the transmission owners did not need to trace benefits to subzones when creating subzones. The Initial Decision finds that this violates Commission requirements that benefits be closely aligned with lost revenues.[247]

243. In addition, the Initial Decision states that AMP-Ohio is an example of cost shifts created by the subzonal allocation in the compliance filings. The Initial Decision states that the AMP-Ohio municipalities were aggregated in one subzone, while costs were allocated based on an average rate. The Initial Decision finds that this resulted in the municipals paying SECA charges based on the loads and power supply selections of others.[248]

244. The Initial Decision states that Ormet is another example of the anomalies created by subzonal allocations. The Initial Decision states that Ormet did not receive benefits due to the elimination of regional through-and-out rates that would justify the enormous

---

[243] *Id.* P 296.

[244] *Id.* P 303.

[245] *Id.* P 311.

[246] *Id.* P 302-03.

[247] *Id.* P 304.

[248] *Id.* P 305.

difference between Ormet's SECA rates and the SECA rates of other AEP native load customers. For example, the Initial Decision states that Ormet did not import power from Midwest ISO after December 31, 2004, and had a reduction in load during the transition period. However, the Initial Decision notes that Ormet is forced to pay a SECA based on its test-period usage, which shifts substantial costs from those entities actually purchasing power during the transition period. The Initial Decision states that the subzones created by AEP punish Ormet and other retail choice customers who chose to take advantage of competitive opportunities and purchase power elsewhere.[249] The Initial Decision concludes that the record establishes that it is unduly discriminatory and inconsistent with cost-causation principles to segregate Ormet in its own subzone.[250]

245. Having found the proposed subzonal allocations to be unjust and unreasonable, the Initial Decision states that the record in this case indicates that there is an alternative approach that could result in a more equitable allocation of the lost revenues.[251] The Initial Decision finds that, as stated by Mr. Russell, using a combined zone with no end-use customer subzones would: (1) avoid rate shock and result in charges low enough not to force load-serving entities out of business; (2) eliminate the issue of collecting a SECA from an entity that is no longer in business; (3) not provide an incentive for utilities to either increase or decrease their loads and would not interfere with the development of the region-wide energy market; (4) be practical, transparent, and simple to implement; and (5) significantly reduce the amount of dollars to be adjusted for known and measurable differences.[252] The Initial Decision finds, for these reasons, that one combined zone for PJM and Midwest ISO would alleviate concerns of preferential treatment and allocation issues.[253] If the Commission rejects the recommendation for one combined zone, the Initial Decision finds that the next best option is two separate zones, one for PJM and one for Midwest ISO.[254]

246. The Initial Decision states that, if the Commission accepts the compliance filings that established subzones, individual subzones are appropriate for Wolverine Power Supply Cooperative, Inc. (Wolverine) and AMP-Ohio. Furthermore, the Initial Decision

[249] *Id.* P 306-307.

[250] *Id.* P 310.

[251] *Id.* P 313.

[252] *Id.* P 314.

[253] *Id.* P 315.

[254] *Id.* P 316.

states that, if the Commission accepts the compliance filings with subzones, then the Ormet subzone should be eliminated.[255]

2. **Briefs on Exceptions**

247. AEP, Dayton, and Exelon, Michigan PPA, Southwestern, Classic PJM TOs, Midwest ISO TOs, and Allegheny and Southern Maryland disagree with the Initial Decision's recommendation that subzones be eliminated. AEP, Dayton, and Exelon argue that this recommendation is contrary to the Commission's explicit directive to develop the SECA charges on a subzonal basis and to allocate lost revenues to each zone or subzone in proportion to the benefits that they will realize due to the elimination of regional through-and-out rates. Classic PJM TOs and Midwest ISO TOs argue that the Initial Decision's finding eliminating subzones is contrary to the Commission's directive to use subzones in order to align benefits and costs and minimize cost shifts. Similarly, Michigan PPA argues that the Commission already determined that the use of subzones was an appropriate mitigation measure to address cost shifting. Southwestern argues that the Commission did not set for hearing the issue of whether the use of subzones was just and reasonable, only whether the design of the zone and subzones was proper. Allegheny and Southern Maryland argue that the Commission did not require, or even permit, socialized SECA charges.

248. Several parties disagree also with the recommendation in the Initial Decision to create a single SECA zone, or alternatively, two RTO-wide zones. Midwest ISO TOs argue that a uniform SECA charge will shift SECA obligations from parties with high SECA obligations to entities that did not have substantial imports across the Midwest ISO-PJM seam during the transition period, which is contrary to the intention of the Commission. Classic PJM TOs argue that, by not using subzone information where it is available (i.e., outside of the Classic PJM footprint), numerous parties that receive little or no benefit due to the elimination of regional through-and-out rates will pay SECA charges while others will pay SECA charges that bear no relation to the benefits that they receive. Midwest ISO TOs and Classic PJM TOs also state that the task of socialization is complicated by the numerous settlements already accepted by the Commission. AEP, Dayton, and Exelon argue that a uniform charge that socializes SECA obligations across the combined region would be unjust and unreasonable because it is incompatible with cost-causation principles. In addition, Michigan PPA and Southwestern argue that the premise to abandon the use of subzones is based solely on anomalies (i.e., Ormet, AMP-Ohio, and the Classic PJM region) that are not representative of the entire combined region.

---

[255] *Id.* P 317.

249. AEP, Dayton, and Exelon argue that the Initial Decision fails to address the substantial evidence that was supplied by the parties that complied with the Commission's order and instead gives "substantial weight" to the assertions of the witness of a non-complying transmission owner, Mr. Bourquin of BG&E. AEP, Dayton, and Exelon argue that Mr. Bourquin's testimony was unsupported and without merit. AEP, Dayton, and Exelon state that Mr. Bourquin is incorrect that North American Electric Reliability Corporation tag data is unreliable because it does not trace deliveries to specific loads within the pre-expansion PJM control area. AEP, Dayton, and Exelon assert that the Commission has been aware that it is impossible to create subzones within the Classic PJM area based on North American Electric Reliability Corporation tags at least since the July 2003 Order. In that order, according to AEP, Dayton, and Exelon, the Commission directed the pre-expansion PJM transmission owners to address alternative methodologies to evaluate the benefits between the various regions within the Classic PJM footprint. AEP, Dayton, and Exelon argue that, absent an alternative methodology, from anyone, to align the relative benefits from import transactions between the various zones of the Classic PJM region, the zonal SECA for Classic PJM is reasonable and in compliance with the Commission's directives.

250. On the issue of the Ormet subzone, AEP, Dayton, and Exelon state that the Commission should reverse the Initial Decision's finding that Ormet should be included in the AEP subzone. AEP, Dayton, and Exelon argue that the Ormet subzone was properly created using North American Electric Reliability Corporation tag data and complies with Commission orders. AEP, Dayton, and Exelon state that the inclusion of Ormet in the AEP subzone would shift Ormet's SECA obligation to AEP's native load customers. AEP, Dayton, and Exelon argue that at no time was Ormet a native load customer of AEP, and including Ormet in the AEP subzone would substantially increase the SECA obligation of every native load customer of AEP.

251. Regarding the Green Mountain subzone, Green Mountain states that the Initial Decision errs in finding that Green Mountain was properly designated as a separate subzone. Green Mountain argues that it demonstrated that the use of North American Electric Reliability Corporation tag data was an unreliable basis upon which to allocate transmission cost responsibility. Furthermore, Green Mountain argues that the use of subzones resulted in Green Mountain being assessed SECA charges for services that it never purchased.

252. On the issue of Duquesne's proposed subzones, Duquesne states that the proposed allocations in the Duquesne subzones are consistent with the Commission's guidance in the SECA proceeding, and should the Commission decide to maintain the established

subzones, the Commission should accept Duquesne's subzonal allocation.[256] Duquesne states that it followed the Commission's directive and assigned each load-serving entity in the Duquesne zone its share of the lost revenues claimed by PJM and Midwest ISO for recovery from the Duquesne zone. Duquesne argues that its witness, Mr. Thomas, carefully reviewed the North American Electric Reliability Corporation tag data used to calculate lost revenues and allocated each MWh of service for each tag to the specific customer that benefited from that use of the system, as well as reflecting the transmission provider that provided the service when developing each of the fixed-rate charges. Duquesne argues that its subzonal allocation also reflects movements in load among the load-serving entities, which is of particular importance given the significant increase in retail shopping that occurred between the test period and the transition period.

253. Duquesne also states that, even though lost revenues are supposed to be allocated to the zone in which the transaction sank, transmission owners allocated claimed lost revenues to the Duquesne zone associated with transactions involving wholesale sales of Orion Power MidWest, L.P. (Orion) that sank outside of the Duquesne zone. Because these transactions did not sink in the Duquesne zone, Duquesne continues, there are no specific entities serving load in the Duquesne zone to which these costs should be allocated. Until these amounts are removed from the lost revenues allocated to the Duquesne zone, Duquesne allocates these amounts to Duquesne subzones on a pro rata basis.[257]

254. Midwest ISO TOs argue that switching to a new rate design at this point is not permissible under the Due Process Clause of the United States Constitution and the Administrative Procedure Act. Midwest ISO TOs argue that they were not aware of a possible rate design change and that the Commission does not have the power to make such changes without adequate notice. Furthermore, Midwest ISO TOs argue that, had the Commission given notice, many more parties with little or no SECA obligation would have intervened and participated. Finally, Midwest ISO TOs state that Commission policy is to implement rate design changes prospectively, and given that the SECA

[256] Duquesne states that, because it expected settlements to resolve most issues related to its subzonal allocations, it did not brief the Presiding Judge on its proposed subzonal allocations. Duquesne states that, therefore, the Presiding Judge did not address Duquesne's proposed subzones in the Initial Decision. Duquesne states, however, that some issues may remain unresolved. Duquesne, therefore, takes exception to the Initial Decision to the extent that it does not approve Duquesne's subzonal allocations, as modified by settlements among Duquesne and load-serving entities in its zone.

[257] Duquesne Brief on Exceptions to the Initial Decision at 29 (*citing* Thomson Test., Ex. No. DLC-1 at 18).

charges are no longer in effect, the Commission cannot change the rate design without violating this policy.

3. Briefs Opposing Exceptions

255. Green Mountain disagrees with parties that maintain that the Commission mandated the use of subzones. Green Mountain argues that these parties fail to recognize that the Commission found that the SECA compliance filings may be unjust and unreasonable, unduly discriminatory or preferential, or otherwise unlawful and set the compliance filings for hearing. Furthermore, Green Mountain states that the list of issues adopted in the Initial Decision specifically included the issue of whether the proposed zones and subzones were appropriate. Green Mountain states that the only argument potentially available to the transmission owners to support their claim that the subzone issue was not at issue in the hearing is that the matter is before the Commission on rehearing. Green Mountain argues, however, that even if the issue is before the Commission on rehearing, it has not been decided by the Commission, and therefore, there is nothing to prevent the Commission from deciding the issue based on the evidence in the record and the findings in the Initial Decision.[258]

256. Ormet also disagrees with AEP, Dayton, and Exelon that the Initial Decision rejects the Commission's directive to use subzones. Ormet argues that the Initial Decision merely recommends that the Commission rethink its position and provides an alternative that would be just and reasonable and not unduly discriminatory or preferential.[259]

257. Quest, Strategic, and WPS Energy disagree with Midwest ISO TOs' suggestion that a uniform charge, as recommended in the Initial Decision, is inconsistent with principles of cost causation. They argue that the concept of charging a SECA only on load-serving entities – and the resulting compliance filings by the transmission owners – is far removed from cost causation from the onset. Quest, Strategic, and WPS Energy claim that, if the elimination of the regional through-and-out rate allows imported power to reduce the locational marginal price, all load-serving entities in those respective markets benefit. They contend, therefore, that a uniform charge over one or two zones is a much closer match of SECA costs to beneficiaries of lower prices than the subzone-based methodology.

---

[258] Green Mountain Brief Opposing Exceptions to the Initial Decision at 11-12.

[259] Ormet Brief Opposing Exceptions to the Initial Decision at 69, 72, 76-77, 81-83.

258. Quest, Strategic, and WPS Energy also state that it prepared a single-zone calculation when it circulated a proposed settlement prior to and during the hearing process, which could be easily modified, adjusted, and used to implement this approach. In addition, Quest, Strategic, and WPS Energy argue that previous bilateral settlements can be accommodated easily, as the settlements do not affect the determination of the uniform charge nor does one party's settlement affect any other party. They also argue that Midwest ISO TOs' argument about cost shifts related to a change to the compliance filings is not only misplaced, it uses circular logic. Quest, Strategic, and WPS Energy asserts that the argument assumes that the compliance filings contain the correct and proper calculation of "obligation" and that, consequently, any change is a "shift." To the contrary, according to Quest, Strategic, and WPS Energy, the compliance filings have not been shown to be just and reasonable so, therefore, cannot be a base from which to judge the effect of changes.

259. Constellation argues that the Commission should adopt a uniform charge across the entire combined region or at least uniform charges within the PJM and Midwest ISO footprints. Constellation states that the use of subzones causes a discriminatory effect, whereby load that was assigned its own subzone was competitively disadvantaged to competitors within a larger subzone. Furthermore, Constellation argues that the use of subzones penalizes customers that used competitive suppliers. Constellation also states that the Commission did not foresee the negative impacts that arose from the use of subzones and argues that the impact cannot be ignored.

260. According to Green Mountain, Midwest ISO TOs' argument that the elimination of subzones could lead to large increases in SECA liability for some parties ignores the fact that the use of subzones caused a large increase to Green Mountain's SECA responsibility. Green Mountain argues that North American Electric Reliability Corporation tag data, which was used to create the subzone assignments in the Midwest ISO TOs' compliance filings, is not a reasonable or reliable basis upon which to allocate transmission cost responsibility as it merely tracks the contract path of power sales and does not measure cost causation. Green Mountain states that the fact that Green Mountain was assigned a SECA responsibility of $32 million demonstrates how far such tag data is far from reflecting which entities caused the incurrence of costs.

261. Ormet states that, contrary to the arguments of AEP, Dayton, and Exelon, the Initial Decision correctly finds that placing Ormet in its own subzone is unjust and unreasonable, and at a minimum, Ormet should be placed into the AEP subzone. Ormet disagrees with AEP, Dayton, and ComEd that placing Ormet in the AEP subzone would substantially increase the SECA liability of AEP's native load customers. Ormet argues that the increase in the AEP subzone rate if Ormet was placed in that subzone is minimal compared to the SECA rate proposed for Ormet. Furthermore, Ormet argues that its subzonal obligation is not proportional to the benefits derived by Ormet due to the elimination of regional through-and-out rates.

262. Exelon, in the AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision, states that it opposes Duquesne's subzonal allocation to the extent that it would allocate responsibility to PECO, which did not serve any load in the Duquesne zone during the test period or transition period. Exelon argues that Duquesne has not adequately supported any proposal to make a hubbing adjustment to PECO.[260]

263. Green Mountain disagrees with Midwest ISO TOs' argument that changing the rate design would violate their rights under the Administrative Procedure Act and the Due Process Clause of the United States Constitution. Green Mountain argues that questions related to the design and appropriateness of the SECA have been at issue at least since 2003. Green Mountain disagrees also with Midwest ISO TOs' argument alleging that changing the subzonal allocations would violate the Commission's policy that rate changes are only made prospectively. Green Mountain states that the Commission has made it clear that SECA charges were subject to refund and surcharge and that parties were put on notice that SECA responsibilities could be increased or decreased.

264. Similarly, Quest, Strategic, and WPS Energy argue that each transmission owner was on notice that a socialized approach to SECA assignment was possible. Quest, Strategic, and WPS Energy state that the issues list compiled by the parties and adopted by the Presiding Judge, which included whether the SECA rate designs comply with the Commission's orders and whether the resulting lost revenue allocations and rates are just and reasonable, provided notice to the parties that a uniform charge was a possible alternative. In addition, they state that Quest and WPS Energy filed testimony and promoted a uniform charge in testimony from the beginning and supported the argument in its brief as well.

4. <u>Commission Determination</u>

265. As noted above, and as the Initial Decision correctly explains, the Commission determined that the SECA should be charged on a subzonal basis, and we will affirm the proposed subzonal SECA charges, subject to specific adjustments directed herein. Therefore, we will reverse the Initial Decision on this issue.

---

[260] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 59-63 (*citing* Thomson Test., Ex. No. DLC-1 at 8-9. Exelon explains that Duquesne's witness Mr. Thompson had testified that SECA responsibility should be allocated to various entities, including PECO, involving a hubbing adjustment for power that was imported into the Duquesne control area by Orion and exported to certain wholesale buyers, principally PECO.

266. The Initial Decision cites Ormet as the primary example of an anomaly created by calculating subzones using North American Electric Reliability Corporation tag data.[261] The Initial Decision explains that customers like Ormet, which had a reduction in load during the transition period, potentially did not benefit from the elimination of regional through-and-out rates but must still pay a SECA based on the higher level of service taken and rates paid during the test period.[262] However, the Commission understood that anomalies such as these could occur and required that transmission owners make adjustments for known and measurable differences. As we discuss in the section on known and measurable differences, we agree that adjustments to the SECA calculations are needed for certain entities, including Ormet. That such adjustments are needed does not mean that North American Electric Reliability Corporation tag data must be rejected altogether.

267. The Initial Decision also asserts that subzonal allocations should be rejected because the benefits to a subzone were not considered in creating the subzones.[263] However, using North American Electric Reliability Corporation tag data to trace specific transactions during the test period and using that information to create subzones *is* a process that considers the benefits that accrue to loads in a subzone due to the elimination of regional through-and-out rates. If energy that was delivered to a subzone during the test period was charged a regional through-and-out rate, then it is reasonable to find that load in that subzone received some benefit due to the elimination of regional through-and-out rates. As we discuss elsewhere in this order, transmission owners must make various adjustments to the SECA subzonal allocations to recognize, for example, known and measurable differences, but the use of North American Electric Reliability Corporation tag data as the baseline is an appropriate, if imperfect, methodology to align those that received benefits due to the elimination of regional through-and-out rates with those that pay the SECA.

268. In addition, the Initial Decision cites the AMP-Ohio municipalities, which AEP has aggregated into one subzone, as an example of the cost shifts caused by the subzonal allocations.[264] However, as AMP-Ohio stated in its Initial Brief, AMP-Ohio and AEP have reached a settlement, and they are working together to create subzones for individual AMP-Ohio municipalities based on the existing tag and other data. This is an issue regarding the implementation of the settlement and has no impact on any other

---

[261] Initial Decision, 116 FERC ¶ 63,030 at P 311.

[262] *Id.* P 306.

[263] *Id.* P 304.

[264] *Id.* P 305.

party in this proceeding.[265] As such, it is not a convincing basis to reject all of the subzonal allocations.

269. We also find that the Initial Decision errs in concluding that subzones punish AEP's retail choice customers who decided to contract with alternative suppliers in 2002 and 2003.[266] Assigning a SECA charge to customers whose load was served by transactions that were assessed regional through-and-out rates during the test period is not a punishment. It merely recognizes that those customers cause some revenue to be lost because they are served by transactions that no longer pay the regional through-and-out rate.

270. We also disagree with the finding in the Initial Decision that using subzones produces unjust and preferential results between the Classic PJM and New PJM regions.[267] The Initial Decision gives significant weight to the testimony of Mr. Bourquin, who explained why it is not possible to use North American Electric Reliability Corporation tag data to create subzones in the Classic PJM region.[268] Instead, SECA charges allocated to the Classic PJM region are divided among all load in the Classic PJM region on a load-ratio share basis. According to the Initial Decision, this creates cost shifts between Classic PJM and New PJM.[269] The Commission, however, has already recognized that the operation of the market might make it impossible to use North American Electric Reliability Corporation tag data to assign SECA charges within the Classic PJM region.[270] The Commission previously found, and we continue to find here based on the record, that parties should use North American Electric Reliability Corporation tag data to calculate SECA charges to create subzones in Midwest ISO and New PJM notwithstanding the fact that such tag data cannot be used to create subzones in Classic PJM. Furthermore, the Initial Decision does not cite evidence in the record to demonstrate or otherwise explain how having subzones in the New PJM region but not in the Classic PJM region creates cost shifts between these two regions. North American Electric Reliability Corporation tag data cannot be used to trace transactions to specific

---

[265] *See* AMP-Ohio Initial Brief at 39-40 and AEP Brief on Exceptions to the Initial Decision at 4-5.

[266] Initial Decision, 116 FERC ¶ 63,030 at P 307.

[267] *Id.* P 311.

[268] *Id.* P 296-300.

[269] *Id.* P 311.

[270] July 2003 Order, 104 FERC ¶ 61,105 at P 54.

loads within Classic PJM, but such tag data can be used to differentiate transactions that served load in Classic PJM and those that served load in New PJM.

271. We also find that the proposal to allocate the SECA to load within the Classic PJM region on a load-ratio share basis is just and reasonable. While not as precise as using North American Electric Reliability Corporation tag data to create zones or subzones, the SECA charges are still calculated based on transactions during the test period that can be traced to the Classic PJM area. The Initial Decision is correct that tags indicating that transactions sink into Classic PJM may actually be passing through Classic PJM for delivery to another control area in New PJM or Midwest ISO or outside of the combined region entirely.[271] However, the Commission recognized this fact and directed parties to make adjustments to the North American Electric Reliability Corporation tag data submitted in the compliance filings to remove such "hubbing" transactions,[272] and we address such proposed hubbing adjustments above.

272. No methodology will perfectly align those that benefit due to the elimination of regional through-and-out rates with those that pay the SECA. No matter what methodology is used, adjustments will need to be made to make the allocation as accurate as possible under the circumstances. Using North American Electric Reliability Corporation tag data where possible and a load-ratio share where such tag data will not work is a reasonable compromise and one that is reasonably consistent with cost-causation principles.

273. Finally, we are not approving any hubbing adjustments for lost revenues included in Duquesne's proposed subzonal allocations. In its Brief on Exceptions to the Initial Decision, Duquesne states that it "excepts to the Initial Decision to the extent it does not approve the [subzonal] allocations of lost revenues in the Duquesne zone (as amended through settlements between Duquesne and other parties)."[273] However, Duquesne's proposed subzonal allocations do *not* include any hubbing adjustment allocation to PECO or to other suppliers outside of the Duquesne zone. Although Duquesne states that transmission owners allocated claimed lost revenues to the Duquesne zone associated with transactions that sank outside of the Duquesne zone, neither it or any other party argues that the Commission should modify Duquesne's proposed subzonal allocations to reflect hubbing adjustments for such transactions.[274] In addition, Duquesne argues in

[271] Initial Decision, 116 FERC ¶ 63,030 at P 298-299.

[272] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 80.

[273] Duquesne Brief on Exceptions to the Initial Decision at 4.

[274] *Id.* at 29.

support of its proposal to allocate to its subzones amounts that might otherwise be subject to a hubbing adjustment.[275] Duquesne has also entered into numerous settlements with various parties related to its SECA obligations. Although Duquesne presented testimony prior to the hearing stating that certain hubbing adjustments to entities such as PECO are appropriate, Duquesne did not brief the Presiding Judge on this issue and did not argue in its Brief on Exceptions to the Initial Decision that its proposed subzonal allocations (which do *not* include a hubbing adjustment) must be changed. Therefore, to the extent necessary, we are not approving any hubbing adjustments to Duquesne's proposed subzonal allocations.

J. Adjustments for Known and Measurable Differences and General and Specific Summary Dispositions

1. March 10 Partial Decision and April 13 Partial Decision

274. The March 10 Partial Decision grants the Motion to Intervene Out of Time of Aquila, given its interest in AMP-Ohio's shift-to-shipper claim, noting that AMP-Ohio did not object to Aquila's late intervention and that the hearing and other parties would not be adversely affected by granting the late intervention.[276] Furthermore, the March 10 Partial Decision grants Aquila's Motion for Summary Disposition and concludes that there are no SECA costs that AMP-Ohio can shift to Aquila on the basis that Contract No. 22 between Aquila and AMP-Ohio[277] expired prior to the transition period.[278] The Presiding Judge states:

> [i]t is found that since the contract terminated before the transition period, it does not meet the criteria imposed by the Commission (it is not a reservation pursuant to requests made on or after November 17, 2003 for service commencing on or after April 1, 2004). Consequently, SECA charges cannot be imposed on this transaction. It is further found Contract No. 22 was not an "existing contract for delivered power that continues into the transition period." Additionally, since the contract at issue terminated before the transition period it is consistent with principles of cost causation not to apply SECA charges to this non-existing transaction since power was not delivered. In essence, there are no "lost revenues" associated with this

[275] *Id.* at 36.

[276] March 10 Partial Decision, 114 FERC ¶ 63,037 at P 7.

[277] Contract No. 22 ended in December 2002.

[278] March 10 Partial Decision, 114 FERC ¶ 63,037 at P 18.

contract in the context of the cited Commission Orders or the SECA transitional mechanism.[279]

275. The Presiding Judge also finds that it is fair to treat AMP-Ohio's answer as a cross motion for summary disposition.[280] The Presiding Judge grants the cross motion for summary disposition, relying on the AMP-Ohio witness who explained why AMP-Ohio should not pay SECA charges associated with contracts expiring prior to the transition period.[281] The Presiding Judge states that neither AMP-Ohio nor Aquila should be paying SECA charges for Contract No. 22.[282]

276. Similarly, the April 13 Partial Decision echoes the findings of the March 10 Partial Decision. Here, the Presiding Judge grants the Motions for Summary Disposition of Dynegy Power Marketing, Inc. (Dynegy), Detroit Edison, Cinergy Services, Inc. (Cinergy), and PSEG, finding that, since Contract Nos. 15 and 25 between DTET and AMP-Ohio[283] and Contract No. 24 between PSEG and AMP-Ohio[284] did not extend into the transition period, they "do not meet the Commission's criteria for imposing or shifting SECA charges."[285] Furthermore, AMP-Ohio's cross motion for summary disposition regarding contracts with DTET and PSEG were granted.[286] Finally, the April 13 Partial Decision notifies parties that during the hearing parties were able to determine "whether these contracts were replaced and by whom" in order to ascertain the appropriate SECA charges.[287]

---

[279] *Id.* (footnote omitted).

[280] *Id.* P 20.

[281] *Id*.

[282] *Id.* P 21.

[283] Contract Nos. 15 and 25 had a term of January 2002 through December 2002 and July 1, 2003, through July 31, 2003, respectively.

[284] Contract No. 24 had a term of December 1, 2003, through December 31, 2002.

[285] April 13 Partial Decision, 115 FERC ¶ 63,011 at P 30.

[286] *Id.*

[287] *Id.* P 31.

a. Briefs on Exceptions

277. Numerous parties take exception to the Presiding Judge's findings in the March 10 Partial Decision and the April 13 Partial Decision that, since the contracts at issue expired prior to the transition period, there are no lost revenues and, therefore, no SECA charges.[288] Midwest ISO TOs argue that this is inconsistent with prior Commission findings and state that load should continue to pay, regardless of whether it has an expired contract, if the load remains and continues to use the exporting utility's transmission system.[289] Furthermore, several parties argue that the Presiding Judge incorrectly assumes that the SECA is a transaction-based charge.[290]

278. Several parties argue that adjusting the SECA for expired contracts is contrary to the Commission's directives to adjust only for known and measurable differences, hubbing transactions, and inaccurate data. They contend that the Commission's directives did not include reducing test-period revenues for contracts that expired prior to the transition period, and in fact, the Commission rejected proposals to "true up" SECA obligations based on actual usage during the transition period.[291] They also assert that the ruling is inconsistent with the Commission's ruling to use North American Electric Reliability Corporation tag data, not contracts, to calculate the lost through-and-out revenues and SECA charges. Midwest ISO TOs and FirstEnergy argue that such tag data does not identify specific contracts and, therefore, could not be used to exclude certain

[288] AEP, Dayton, and Exelon Brief on Exceptions to the March 10 Partial Decision at 14-15 and 16-17; FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 16-17 and April 13 Partial Decision at 14-16; Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 11 and April 13 Partial Decision at 6-7; and Trial Staff Brief on Exceptions to the March 10 Partial Decision at 8, 11-12 and April 13 Partial Decision at 11-13.

[289] Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 16.

[290] AEP, Dayton, and Exelon Brief on Exceptions to the March 10 Partial Decision at 8 and April 13 Partial Decision at 13-14; FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 24; and Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 15.

[291] Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 11-12, 13; FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 16, 24-27 and April 13 Partial Decision at 14-16, 23-25. *See also* AEP, Dayton, and Exelon Brief on Exceptions to the April 13 Partial Decision at 12-13.

contracts when developing SECA charges.[292] Furthermore, many parties argue that the Presiding Judge's ruling is contrary to the Commission's directive to maintain revenue neutrality.[293]

279. FirstEnergy Service states that the Presiding Judge confuses the Commission's criteria for establishing a shift-to-shipper claim with the criteria for calculating lost revenues and SECA obligations.[294] FirstEnergy Service also argues that the March 10 Partial Decision erroneously addresses the SECA rate mechanism even though it was not set for hearing. FirstEnergy Service contends that the Commission set for hearing the compliance filings to determine who pays the SECA and whether any adjustments were required to the SECA to make it just and reasonable.[295]

280. AMP-Ohio explains that, if the Commission were to reverse the Presiding Judge's ruling that there should be no SECA charges associated with contracts that do not extend into the transition period, the Commission should also reverse the finding that parties cannot seek shift-to-shipper claims to sellers under delivered power contracts that do not extend into the transition period.[296]

281. With respect to the Presiding Judge's decision to treat AMP-Ohio's answer as a cross motion for summary disposition, AEP, Dayton, and Exelon and FirstEnergy Service state that the March 10 Partial Decision and the April 13 Partial Decision were issued

[292] FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 18-19 and April 13 Partial Decision at 16-18; Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 16-17 and April 13 Partial Decision at 8.

[293] Midwest ISO TOs Brief on Exceptions to the March 10 Partial Decision at 5-6; AEP, Dayton, and Exelon Brief on Exceptions to the April 13 Partial Decision at 8-10; FirstEnergy Service Brief on Exceptions to the April 13 Partial Decision at 18-20; and Trial Staff Brief on Exceptions to the April 13 Partial Decision at 13.

[294] FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 27-29 and April 13 Partial Decision at 26-28. *See also* AEP, Dayton, and Exelon Brief on Exceptions to the April 13 Partial Decision at 10-12.

[295] *Id.* at 29-30.

[296] AMP-Ohio Brief on Exceptions to the March 10 Partial Decision at 5-7.

sua sponte in violation of Commission Rule 217(c)(2).[297] They argue that there was no summary disposition before the judge asking for the elimination of SECA charges assigned to AMP-Ohio and only a summary disposition of shift-to-shipper claims. Further, they contend that participants were not given an opportunity to comment, nor did the Presiding Judge find "good cause" to circumvent the procedural requirements.

282. Finally, Detroit Edison takes exception to Paragraph 31 of the April 13 Partial Decision where the Presiding Judge states that parties were able to explore, during the hearing, whether contracts that expired prior to the transition period were replaced and by whom to determine the appropriate SECA charges.[298] Detroit Edison states that SECA obligations are based on historical import behavior.[299]

b. Briefs Opposing Exceptions

283. A number of parties agree with the Presiding Judge's overall finding in the March 10 Partial Decision and the April 13 Partial Decision to dismiss certain shift-to-shipper claims for contracts that did not extend into the transition period. Furthermore, these parties agree with the Presiding Judge that there should be no SECA obligations associated with contracts that expired prior to the transition period.[300]

284. Several parties contend that the adjustment to SECA obligations for known and measurable differences include inter-period differences (i.e., the differences between the

[297] AEP, Dayton, and Exelon Brief on Exceptions to the March 10 Partial Decision at 31-32 and April 13 Partial Decision at 21-22; and FirstEnergy Service Brief on Exceptions to the March 10 Partial Decision at 21-23 and April 13 Partial Decision at 29-33; *see* 18 C.F.R. § 385.217(c)(2) (2009).

[298] Detroit Edison Brief on Exceptions to the April 13 Partial Decision at 2.

[299] *Id.* at 8.

[300] *See, e.g.*, Aquila, Detroit Edison, Duquesne, and Indicated SECA Payers Briefs Opposing Exceptions to the March 10 Partial Decision. *See also* AMP-Ohio, CCG, Duquesne, FirstEnergy Service, Michigan PPA and Michigan SCPA, Ormet, and Indicated SECA Payers Briefs Opposing Exceptions to the April 13 Partial Decision.

test period and the transition period).[301] Specifically, they argue that these known and measurable differences include adjustments for contracts that expired prior to the transition period. Indicated SECA Payers contend that, were regional through-and-out rates retained, the transmission owners would not have earned transmission revenues from these non-existent transactions. Furthermore, they argue that this is consistent with the basic SECA theory to recover lost revenues resulting from the elimination of regional through-and-out rates.[302] Moreover, Indicated SECA Payers argue that, absent the adjustments to reflect these known and measurable differences, SECA charges would constitute illegal retroactive ratemaking.[303]

285. With regard to AMP-Ohio's Brief on Exceptions to the March 10 Partial Decision, several parties argue that the Presiding Judge correctly finds that the plain meaning of the November 2003 Rehearing Order permits load-serving entities the opportunity to shift a portion of their SECA obligation to the shipper for existing contracts that continue into the transition period.[304] In addition, Indicated SECA Payers argue that the Presiding Judge's ruling to accept AMP-Ohio's answer as a cross motion for summary disposition was proper and that parties were provided with adequate notice and opportunity to comment pursuant to Commission Rule 217(c)(2).[305]

---

[301] Duquesne Brief Opposing Exceptions to the March 10 Partial Decision at 10-14 and April 13 Partial Decision at 4-6; Indicated SECA Payers Brief Opposing Exceptions to the March 10 Partial Decision at 7-8 and April 13 Partial Decision at 6-11; Michigan PPA and Michigan SCPA Brief Opposing Exceptions to the April 13 Partial Decision at 6; AMP-Ohio Brief Opposing Exceptions to the April 13 Partial Decision at 6-8; and Ormet Brief Opposing Exceptions to the April 13 Partial Decision at 3-5.

[302] Indicated SECA Payers Brief Opposing Exceptions to the March 10 Partial Decision at 6-7.

[303] Indicated SECA Payers Brief Opposing Exceptions to the March 10 Partial Decision at 11-15 and April 13 Partial Decision at 11-15.

[304] *See* Aquila Brief Opposing Exceptions to the March 10 Partial Decision; Detroit Edison Brief Opposing Exceptions to the March 10 Partial Decision; and FirstEnergy Service Brief Opposing Exceptions to the March 10 Partial Decision.

[305] Indicated SECA Payers Brief Opposing Exceptions to the March 10 Partial Decision at 30-34 and April 13 Partial Decision at 30-34.

2. Initial Decision

a. Quest Contracts

i. Initial Decision

286. The Initial Decision notes that Quest, Strategic, and WPS Energy claimed that there are two known and measurable changes that should be reflected in its SECA charge due to contracts not extending into the transition period. First, they argued that deliveries to NOAC under a Power Purchase Agreement with AEM should be removed because service was for the period January 1, 2003, through December 31, 2003. Quest, Strategic, and WPS Energy stated that Quest did not serve the NOAC load during the transition period that the SECA was in effect.[306] Likewise, they argued that deliveries to North Star should be removed because Quest stopped serving this retail load in April 2004.[307]

287. The Initial Decision states that the contract expiration issue was addressed in the March 10 Partial Decision and April 13 Partial Decision. The Initial Decision states that this is sufficient to resolve the issues raised by Quest in its favor.[308] The Initial Decision, citing the March 10 Partial Decision, states "that the Commission envisioned that the SECA would apply to transactions involving reservations pursuant to requests made on or after November 17, 2003 for service commencing after April 1, 2004."[309] Furthermore, the Initial Decision states that the March 10 Partial Decision finds "that SECA charges are for contracts for delivered power that continue into the transition period."[310] Moreover, the Presiding Judge states that the March 10 Partial Decision finds that the SECA could not be imposed on a contract that terminated prior to the transition period.[311] The Initial Decision concludes that, based on the reasoning in the March 10 Partial

[306] Initial Decision, 116 FERC ¶ 63,030 at P 47 (*citing*, *e.g.*, Zakem Answering Test., Ex. No. QST-1 at 33).

[307] *Id.* (*citing*, *e.g.*, Quest, Strategic, and WPS Energy Initial Brief at 39-40).

[308] *Id.* P 50.

[309] *Id.* P 49 (*citing* March 10 Partial Decision, 114 FERC ¶ 63,037 at P 16).

[310] *Id.* (*citing* March 10 Partial Decision, 114 FERC ¶ 63,037 at P 16).

[311] *Id.* (*citing* March 10 Partial Decision, 114 FERC ¶ 63,037 at P 16).

Decision and April 13 Partial Decision, Quest should not have been charged with SECA charges for contracts that expired during the transition period.[312]

ii. Briefs on Exceptions

288. Midwest ISO TOs disagree with the Presiding Judge's finding that contracts that do not extend into the transition period are not eligible for SECA charges.[313] Midwest ISO TOs argue that this finding improperly transforms the SECA into a transaction-based charge, which is contrary to the Commission's orders clearly establishing a load-based charge.[314] Midwest ISO TOs contend that the Commission never indicated that a contract terminating prior to the transition period would result in a SECA charge reduction.[315] Midwest ISO TOs state that the Commission previously denied the use of actual invoices to assign SECA responsibility because it would result in under recovery of lost revenues and unfair results due to power marketers' ability to change their trading activity from year to year.[316] Furthermore, Midwest ISO TOs argue that the use of contracts to determine SECA responsibility diverges from the Commission's directive to use North American Electric Reliability Corporation tag data to calculate the SECA.[317]

289. AEP, Dayton, and Exelon state that Quest, Strategic, and WPS Energy did not move for summary disposition but that the Presiding Judge grants adjustments for known and measurable differences in the Initial Decision based on interpretations of the Commission's orders set forth in the March 10 Partial Decision and April 13 Partial Decision. AEP, Dayton, and Exelon state that the Commission should reject the Initial Decision's interpretation of known and measurable differences.[318] AEP, Dayton, and Exelon argue that the Presiding Judge's finding to adjust Quest's SECA charges to reflect that the NOAC contract terminated prior to the transition period transforms the SECA into a transactional charge and is at odds with the Commission's order that the SECA must be a load-based charge. Alternatively, AEP, Dayton, and Exelon argue that, if the Commission does not reverse this finding, Quest's SECA charges related to the NOAC

[312] *Id.* P 50.

[313] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 69-70.

[314] *Id.* at 70-71.

[315] *Id.* at 71.

[316] *Id.* at 72.

[317] *Id*.

[318] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 79.

contract should be shifted to FirstEnergy because it was the load-serving entity that served that load following the termination of the NOAC contract in December 2003.[319]

290. AEP, Dayton, and Exelon also disagree with the Presiding Judge's findings to grant both of Quest's proposed adjustments for known and measurable differences because the compliance filings did not require, and could not have required, the filing to include adjustment for known and measurable differences for changes that occurred during the transition period.[320] AEP, Dayton, and Exelon assert that the only appropriate standard for known and measurable differences is one that limits adjustments to anomalous circumstances that existed during the 2002 and 2003 test periods in order to maintain the Commission's goals of revenue neutrality and avoiding cost shifts to transmission owner's native load customers.[321]

iii. Briefs Opposing Exceptions

291. Quest, Strategic, and WPS Energy take exception to AEP, Dayton, and Exelon's contention that Quest's adjustments do not qualify because a known and measurable change is something that occurred only during the test period (i.e., 2002 and 2003 test periods). Quest, Strategic, and WPS Energy assert that a known and measurable change is a post-test period change that need only be known and measurable at the time of the filing. They state that the known and measurable change was known and measurable prior to the effective date of the rate.

292. FirstEnergy argues that there is no basis to assign the NOAC SECA to FirstEnergy's regulated and unregulated load-serving entities.[322] FirstEnergy argues that the SECA obligations assigned to Quest are for Quest's own transactions, and not FirstEnergy's. FirstEnergy argues that there is no record evidence, much less substantial evidence, that FirstEnergy picked up Quest's NOAC load. Therefore, FirstEnergy argues that there is no basis upon which to require FirstEnergy to pay Quest's SECA.[323]

293. BG&E agrees with the Presiding Judge that, if there is no transaction during the collection period for which a regional through-and-out rate would have been assigned,

---

[319] *Id.* at 80-81.

[320] *Id.* at 81.

[321] *Id*.

[322] FirstEnergy Brief Opposing Exceptions to the Initial Decision at 24.

[323] *Id.* at 26.

there are no lost revenues and no SECA can be assigned.[324] Furthermore, BG&E states that "SECA charges are for contracts for delivered power that *continue into the transition period*."[325] BG&E argues that, by failing to exclude expired contracts, the SECA filers have not provided just and reasonable rates.[326] BG&E asserts that the SECA filers have failed to accurately quantify lost revenues because they have not tracked contracts associated with every reservation during the test period to determine if the contract had terminated.[327]

b. <u>CMS Energy</u>

i. <u>Initial Decision</u>

294. CMS Energy filed a Motion for Partial Summary Disposition on March 9, 2006. The motion was denied, and CMS Energy renewed its motion on May 5, 2006. The Presiding Judge grants the motion on the ground that CMS Energy stated that it did not take service during the transition period at the MECS.DECO.CMSZ sink.[328] The Presiding Judge states that no party disputed CMS Energy's assertion that it had not served retail load at the sink or that it moved or had moved power through and out of the PJM system to serve retail load at that sink since September 2003.[329] The Presiding Judge, relying on the finding in the March 10 Partial Decision and April 13 Partial Decision, states that a contract not extending into the transition period "is an absolute limitation on the ability to impose a SECA charge on a [load-serving entity]."[330] The Initial Decision also states that, if an entity did not take transmission service during the transition period, there is no benefit associated with the elimination of regional through-and-out rates on which to base a SECA charge.[331]

---

[324] BG&E Brief Opposing Exceptions to the Initial Decision at 24.

[325] *Id.* at 25 (*citing* March 10 Partial Decision, 114 FERC ¶ 63,037 at P 16 (emphasis added by BG&E)).

[326] *Id.* at 32.

[327] *Id.* at 27.

[328] Initial Decision, 116 FERC ¶ 63,030 at P 571 (*citing* Tr. 1369:12-21 (Warren)).

[329] *Id.* P 581.

[330] *Id.* P 582.

[331] *Id.*

ii. **Briefs on Exceptions**

295. Midwest ISO TOs state that the Presiding Judge's finding that CMS Energy did not serve load during certain months of the transition period does not indicate who did serve the load no longer served by CMS Energy.[332] Midwest ISO TOs argue that the Presiding Judge acknowledges their argument that, if CMS Energy was not responsible for certain SECA charges associated with that load, the entity that did serve the load should be paying those SECA charges.[333] Furthermore, Midwest ISO TOs state that the Presiding Judge encourages parties to explore who did serve the load after certain contracts expired.[334]

296. AEP, Dayton, and Exelon request that the Commission reverse the Presiding Judge's ruling to grant summary disposition to CMS Energy. Alternatively, AEP, Dayton, and Exelon request that the Commission reject the Initial Decision's alternative finding to adopt known and measurable differences adjustments.[335] AEP, Dayton, and Exelon state that the Presiding Judge's findings rely on the March 10 Partial Decision and not on the claims that the compliance filings violate the filed rate doctrine and the rule against retroactive ratemaking. AEP, Dayton, and Exelon request that, if the Commission reverses the findings in the March 10 Partial Decision, the Commission also reverse the Initial Decision's findings regarding CMS Energy's Motion for Summary Disposition.[336] Furthermore, AEP, Dayton, and Exelon argue that this finding to relieve CMS Energy of its SECA charges undermines the principle of revenue neutrality.[337] AEP, Dayton, and Exelon also state that the Presiding Judge's alternative recommendation is illogical because, as CMS Energy clarified during the proceeding, CMS Energy did not serve load during the transition period, and therefore, an adjustment for known and measurable differences was not required, and could not have been required, because the changes occurred during the transition period.[338]

---

[332] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 73.

[333] *Id.* at 74.

[334] *Id.*

[335] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 77.

[336] *Id.* at 78.

[337] *Id.*

[338] *Id.* at 78-79.

iii. Brief Opposing Exceptions

297. CMS Energy states that no one disputes that CMS Energy did not serve any retail load at the MECS.DECO.CMSZ sink during the transition period.[339]

c. Green Mountain

i. Initial Decision

298. Green Mountain filed a Motion for Partial Summary Disposition on March 22, 2006. The motion was denied, and Green Mountain renewed its motion on May 5, 2006. The Initial Decision notes that Green Mountain stated that it served no load in the Midwest ISO footprint between January and March of 2006 and should not be liable for the $2.2 million that it was assessed for each of those months.[340] Green Mountain argued that the charges were solely based on transactions that sank in its subzone in 2003 without regard to whether Green Mountain purchased or provided service in 2006.[341] The Presiding Judge grants Green Mountain's motion, stating that Green Mountain's claim that it served no load from January through March of 2006 was undisputed.[342] The Presiding Judge states that the same reasoning of the March 10 Partial Decision and April 13 Partial Decision apply in this instance.[343] The Presiding Judge clarifies "that simply because a contract for 'delivered' power continued into the transition period does not give [Midwest ISO] license to collect [SECA charges] for the entire two year period without regard to whether entities served load."[344]

ii. Briefs on Exceptions

299. AEP, Dayton, and Exelon state that the Presiding Judge's decision to grant Green Mountain's Motion for Summary Disposition and relieve Green Mountain's obligation to pay SECA charges for the final three months of the transition period undermines the principle of revenue neutrality. Furthermore, AEP, Dayton, and Exelon assert that the Presiding Judge's failure to specify an alternative means of collecting those SECA

---

[339] CMS Energy Brief Opposing Exceptions to the Initial Decision at 13.

[340] Initial Decision, 116 FERC ¶ 63,030 at P 588.

[341] *Id.*

[342] *Id.* P 595.

[343] *Id.*

[344] *Id.* P 597.

charges from Green Mountain threatens to impose cost shifts on a transmission owner's native load customers. AEP, Dayton, and Exelon state that, should the Commission not reverse this finding, FirstEnergy should be directed to pay the shifted SECA obligation because FirstEnergy began serving Green Mountain load when Green Mountain exited Midwest ISO on December 31, 2005.[345]

300. AEP, Dayton, and Exelon argue that the Commission could not and did not require adjustments for known and measurable differences in the compliance filings that occurred during the transition period. Furthermore, AEP, Dayton, and Exelon assert that Green Mountain's decision to exit the retail business for the last three months of the transition period was clearly to avoid liability for SECA charges. AEP, Dayton, and Exelon argue that this is the very opportunistic behavior that the Commission sought to avoid by using calendar-year 2002 and 2003 data as test periods.[346]

301. Midwest ISO TOs state that the Presiding Judge's finding that Green Mountain did not serve load during certain months of the transition period does not indicate who did serve the load no longer served by Green Mountain.[347] Midwest ISO TOs argue that the Presiding Judge acknowledges their argument that, if Green Mountain was not responsible for certain SECA charges associated with that load, the entity that did serve the load should be paying those SECA charges.[348] Furthermore, Midwest ISO TOs state that the Presiding Judge encourages parties to explore who did serve the load after certain contracts expired.[349]

iii. <u>Briefs Opposing Exceptions</u>

302. FirstEnergy argues that there is no basis to assign Green Mountain's SECA to FirstEnergy's load-serving entities.[350] FirstEnergy argues that the SECA obligations assigned to Green Mountain are for its own transactions and not FirstEnergy's. Furthermore, FirstEnergy states that the FirstEnergy Provider of Last Resort and FirstEnergy Solutions' loads were allocated subzonal SECA charges based on their own transactions during the transition period. FirstEnergy argues that, even if the

---

[345] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 74-75.

[346] *Id.* at 75.

[347] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 73.

[348] *Id.* at 74.

[349] *Id.*

[350] FirstEnergy Brief Opposing Exceptions to the Initial Decision at 24.

Commission decides that the entity that served Green Mountain's load during the remainder of the transition period is responsible for the SECA, there is no record evidence that FirstEnergy served Green Mountain load either before or after Green Mountain exited the market on December 31, 2005.[351] FirstEnergy states that Midwest ISO and AEP, Dayton, and Exelon were informed by FirstEnergy during the hearing that, as of January 1, 2006, any entity that was formally served by Green Mountain that did not choose another competitive retail electric supplier in Ohio would have been supplied by Ohio Edison or CEI, not FirstEnergy.[352]

303. Green Mountain states that the Presiding Judge correctly finds that Green Mountain owes no SECA liability for January through March of 2006.[353]

d. Michigan PPA

i. Initial Decision

304. Michigan PPA filed with the Presiding Judge an Initial Brief and a Motion for Partial Summary Disposition on June 9, 2006. First, Michigan PPA stated that, of the 100,512 MWh of energy that its Power Pool Project purchased from AEP in 2002, 60,577 MWh were imported from AEP in January and February of 2002 due to tornado damage to its Lansing Erikson generating unit and scheduled maintenance to the Belle River unit.[354] Michigan PPA stated that, when the Lansing Erikson unit came back online in February of 2002, its purchases from AEP decreased by approximately 92 percent.[355] Michigan PPA also stated that its purchases from AEP dropped to 39,890 MWh in 2003 and 21,404 MWh from January 1, 2004, to November 20, 2004. Furthermore, Michigan PPA stated that, since the beginning of the transition period, Michigan PPA purchased only 4,272 MWh from AEP that was transmitted across the seam pursuant to short-term contracts executed after the test period.[356] Michigan PPA also stated that its purchases from AEP were zero from April 2005 to March 2006.[357] Second, Michigan PPA stated

[351] *Id.* at 25.

[352] *Id.* at 25-26.

[353] Green Mountain Brief Opposing Exceptions to the Initial Decision at 19-21.

[354] Initial Decision, 116 FERC ¶ 63,030 at P 599.

[355] *Id.*

[356] *Id.* P 600.

[357] *Id.*

that all of its test-period contracts with AEP expired prior to the transition period, and therefore, it should not be assessed SECA charges for those contracts.[358] Michigan PPA requested that the Presiding Judge find that Michigan PPA had no SECA obligation and that Midwest ISO should refund, with interest, all SECA charges paid by Michigan PPA.[359]

305. The Initial Decision states that Michigan PPA's argument that it could not be assessed SECA charges because all of its test-period contracts expired prior to the transition period, and that the only transactions during the transition period were entered into after the test period for which a SECA could not be assessed, was misplaced.[360] The Presiding Judge states that the Commission did not impose a requirement that contracts needed to be executed during the test period to be eligible for a SECA charge. The Presiding Judge finds that, while Michigan PPA's contracts that did terminate prior to the transition period are not SECA eligible (i.e., approximately 140,402 MWh of imports), Michigan PPA's other purchases during the transition period are eligible.[361] Moreover, the Presiding Judge denies Michigan PPA's Motion for Summary Disposition to the extent that Michigan PPA is not entitled to have its entire SECA liability eliminated.[362] However, the Initial Decision states that, should the Commission accept the compliance filings as filed, Michigan PPA's SECA obligation should be adjusted for known and measurable differences to reflect 140,402 MWh associated with contracts that did not continue into the transition period.[363]

ii. <u>Briefs on Exceptions</u>

306. Michigan PPA states that the Presiding Judge correctly grants the summary judgment recognizing that Michigan PPA's test-period revenues were not SECA eligible and, therefore, could not be included in Michigan PPA's SECA calculation.[364] However, Michigan PPA takes exception to the Presiding Judge's finding that Michigan PPA's other purchases during the transition period are eligible for SECA charges. Michigan

---

[358] *Id.* P 601.

[359] *Id.*

[360] *Id.* P 609.

[361] *Id.* P 609-610.

[362] *Id.* P 610.

[363] *Id.* P 611.

[364] Michigan PPA Brief on Exceptions to the Initial Decision at 15.

PPA argues that, if there are no test-period transactions that qualify as SECA transactions, there are no transactions upon which a rate can be calculated to apply during the transition period.[365] Furthermore, Michigan PPA argues that it demonstrated that all imports ceased as of April 1, 2005.[366] Michigan PPA argues that this finding is akin to converting the SECA from a load-based charge to a transaction-based charge for transactions that occur during the transition period.[367] Michigan PPA states that the SECA principles adopted by the Commission do not look at import transactions during the transition period.[368]

307. Michigan PPA also states that the Presiding Judge fails to find a known and measurable change related to Michigan PPA's purchases from AEP during January and February 2002.[369] Michigan PPA states that this issue may be moot if the Commission upholds the finding in the Initial Decision that only 2003 test-period data be used.[370] Michigan PPA argues, however, that Michigan PPA's purchases on behalf of the power pool in January and February of 2002 are not representative of the type of purchases of normal Michigan PPA operations and are, therefore, representative of the type of known and measurable differences that the Commission recognizes.[371]

308. AEP, Dayton, and Exelon state that the Presiding Judge correctly finds that not all of Michigan PPA's SECA liability to AEP should be eliminated.[372] AEP, Dayton, and Exelon argue, however, that Michigan PPA's alternative request to grant an adjustment for known and measurable differences for imports from AEP in January 2002 and February 2002 should be rejected because it was not adequately supported by record

[365] *Id.* at 15, 17.

[366] *Id.* at 15-16.

[367] *Id.* at 16-17.

[368] *Id.* at 16.

[369] *Id.* at 17.

[370] *Id.*

[371] *Id.* at 18-21.

[372] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 83.

evidence.[373] Furthermore, AEP, Dayton, and Exelon argue that relieving Michigan PPA of it SECA obligation undermines the principle of revenue neutrality.[374]

309. Midwest ISO TOs disagree with the Presiding Judge's finding that contracts that do not extend into the transition period are not eligible for SECA charges.[375] Midwest ISO TOs argue that this finding improperly transforms the SECA into a transaction-based charge, which is contrary to the Commission's orders clearly establishing a load-based charge.[376] Midwest ISO TOs contend that the Commission never indicated that a contract terminating prior to the transition period would result in a SECA charge reduction.[377] Midwest ISO TOs state that the Commission previously denied the use of actual invoices to assign SECA responsibility because it would result in under recovery of lost revenues and unfair results due to power marketers' ability to change their trading activity from year to year.[378] Furthermore, Midwest ISO TOs argue that the use of contracts to determine SECA responsibility diverges from the Commission's directive to use North American Electric Reliability Corporation tag data to calculate the SECA.[379]

iii. <u>Briefs Opposing Exceptions</u>

310. Michigan PPA states that the Presiding Judge correctly finds that all of Michigan PPA's 2002 and 2003 test year transactions must be removed from the SECA calculations because these transactions terminated prior to the transition period.[380] Michigan PPA also states that this finding renders Michigan PPA's alternative request moot (i.e., adjustments for known and measurable differences for atypical purchases from AEP in January and February of 2002).[381]

---

[373] *Id.* at 83.

[374] *Id.* at 84.

[375] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 69-70.

[376] *Id.* at 70-71.

[377] *Id.* at 71.

[378] *Id.* at 72.

[379] *Id*.

[380] Michigan PPA Brief Opposing Exceptions to the Initial Decision at 8-11.

[381] *Id.* at 7.

311. AEP, Dayton, and Exelon state that the Presiding Judge correctly finds that Michigan PPA did not provide adequate support to require adjustments for known and measurable differences relating to Michigan PPA's claims that its imports from AEP during January and February of 2002 were atypical.[382]

e. Old Dominion

i. Initial Decision

312. Multiple TDUs, including Old Dominion, filed with the Presiding Judge a Motion for Partial Summary Disposition on March 13, 2006. The motion was denied, and Old Dominion renewed its motion in Four TDUs' reply brief submitted on June 27, 2006. Old Dominion requested that the Ironwood contract be excluded from the SECA obligation because the contract did not continue into the transition period and was not replaced with other imports that crossed the seam during the transition period. Old Dominion stated that, during the first five months of 2003, Old Dominion had a contract with Williams Energy Marketing & Trading Company (Williams) for power sourced and sold at the AES Ironwood generating plant located within Classic PJM.[383] In order to import this power, Old Dominion had a 490 MW transmission reservation on the path from Ironwood to the Dominion zone. The contract with Williams and the associated transmission reservation expired by its own terms on May 31, 2003.[384] The Presiding Judge grants the summary disposition and finds that Old Dominion's SECA obligation to BG&E must be adjusted to exclude the imports associated with the Ironwood contract, and thus, any resulting overpayment must be refunded with interest.[385]

ii. Brief on Exceptions

313. Midwest ISO TOs disagree with the Presiding Judge's finding that contracts that do not extend into the transition period are not eligible for SECA charges.[386] Midwest ISO TOs argue that this finding improperly transforms the SECA into a transaction-based charge, which is contrary to the Commission's orders clearly establishing a load-based

---

[382] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 51-52.

[383] Initial Decision, 116 FERC ¶ 63,030 at P 615.

[384] *Id.*

[385] *Id.* P 616.

[386] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 69-70.

charge.[387] Midwest ISO TOs contend that the Commission never indicated that a contract terminating prior to the transition period would result in a SECA charge reduction.[388] Midwest ISO TOs state that the Commission previously denied the use of actual invoices to assign SECA responsibility because it would result in under recovery of lost revenues and unfair results due to power marketers' ability to change their trading activity from year to year.[389] Furthermore, Midwest ISO TOs argue that the use of contracts to determine SECA responsibility diverges from the Commission's directive to use North American Electric Reliability Corporation tag data to calculate the SECA.[390]

iii. Brief Opposing Exceptions

314. Four TDUs state that the Initial Decision properly finds that Old Dominion's SECA payments to BG&E should be adjusted to remove the test-period MWhs associated with the Ironwood contract that did not extend into the transition period; the Ironwood contract expired on May 31, 2003, and was not rolled over.[391] Four TDUs state that no party seeks exception to this finding in the Initial Decision. Furthermore, Four TDUs explain that Old Dominion entered into the Ironwood contract to fill a need for 490 MW of firm capacity because a new 500 MW combustion turbine plant that Old Dominion was building within the Dominion zone was not operational until June 2003, which is the same type of resource as the Ironwood plant.[392] Four TDUs explain that the out-of-zone power purchase, and corresponding import, has not recurred. Finally, Four TDUs explain that Old Dominion has made arrangements and has access to energy from gas-fired, combined-cycle combustion turbines from within its own zone and will, therefore, not need to purchase energy across the PJM-Dominion border.[393]

---

[387] *Id.* at 70-71.

[388] *Id.* at 71.

[389] *Id.* at 72.

[390] *Id*.

[391] Four TDUs Brief Opposing Exceptions to the Initial Decision at 24-26.

[392] *Id*. at 27-28 (*citing* Scarpignato Answering Test., Ex. No. MTDU-10 at 5-6).

[393] *Id*. at 28 (*citing* Scarpignato Answering Test., Ex. No. MTDU-10 at 5-6).

f. Ormet

i. Initial Decision

315. Ormet filed with the Presiding Judge a Motion for Partial Summary disposition on March 20, 2006. The motion was denied, and Ormet renewed its motion on May 18, 2006. Ormet's motion argues that: (1) the proposed SECA constitutes retroactive ratemaking; (2) its SECA obligation must be adjusted for known and measurable differences; and (3) its expired supply contracts should not be used in calculating its SECA obligation.[394] Ormet argues, with respect to adjustments for known and measurable differences, that its 535 MW test-period load decreased during the transition period to 8 MW on December 20, 2005, and therefore, Ormet's SECA obligation should be adjusted.[395] Ormet also argues that its SECA obligation should be adjusted, consistent with the March 13 Partial Decision, to reflect that Ormet purchased no power outside of PJM after December 31, 2005, because those contracts terminated or were no longer applicable to Ormet.[396] The Presiding Judge states that Ormet's retroactive ratemaking issue was addressed in the Rate Design and Lost Revenues section of the Initial Decision.[397] Furthermore, the Presiding Judge grants Ormet's summary disposition to the extent that its SECA obligation was not adjusted for known and measurable differences to reflect the change in load from 535 MW to 8 MW.[398] The Presiding Judge also states, with respect to Ormet's supply contracts, that they only existed for one month of the sixteen-month transition period and cannot serve as the basis of SECA charges beyond the contract's duration.[399] Therefore, the Presiding Judge finds that Ormet should only be assessed a SECA for the supply contracts for the period of December 1, 2004, through December 31, 2004.[400]

---

[394] *Id.* P 617.

[395] *Id.* P 619.

[396] *Id.*

[397] *Id.* P 625.

[398] *Id.* P 626.

[399] *Id.* P 627.

[400] *Id.*

ii. **Briefs on Exception**

316. AEP, Dayton, and Exelon state that the Commission should reverse the known and measurable adjustment granted to Ormet as well as the SECA relief granted in its Motion for Summary Disposition that is based on the findings in the March 10 Partial Decision and April 13 Partial Decision.[401] AEP, Dayton, and Exelon argue that reductions in Ormet's load during the transition period are not the type of anomalous test-period occurrences that constitute adjustments for known and measurable differences that could have been included in the compliance filings.[402] AEP, Dayton, and Exelon argue that, if the Commission finds that the SECA rates should reflect changes in load that occur between the test period and the transition period, the Commission should allow rates for all non-settling parties to be revised to reflect load changes.[403] AEP, Dayton, and Exelon also state that rates within PJM should be developed based on test-period load and that a load-serving entity's prior year's 1-CP should be used as the billing determinant during the transition period.[404]

317. Midwest ISO TOs disagree with the Presiding Judge's finding that contracts that do not extend into the transition period are not eligible for SECA charges.[405] Midwest ISO TOs argue that this finding improperly transforms the SECA into a transaction-based charge, which is contrary to the Commission's orders clearly establishing a load-based charge.[406] Midwest ISO TOs contend that the Commission never indicated that a contract terminating prior to the transition period would result in a SECA charge reduction.[407] Midwest ISO TOs state that the Commission previously denied the use of actual invoices to assign SECA responsibility because it would result in under recovery of lost revenues and unfair results due to power marketers' ability to change their trading activity from year to year.[408] Furthermore, Midwest ISO TOs argue that the use of

---

[401] AEP, Dayton, and Exelon Brief on Exceptions to the Initial Decision at 82.

[402] *Id.*

[403] *Id.*

[404] *Id.*

[405] Midwest ISO TOs Brief on Exceptions to the Initial Decision at 69-70.

[406] *Id.* at 70-71.

[407] *Id.* at 71.

[408] *Id.* at 72.

contracts to determine SECA responsibility diverges from the Commission's directive to use North American Electric Reliability Corporation tag data to calculate the SECA.[409]

iii. Brief Opposing Exceptions

318. Ormet states that AEP, Dayton, and Exelon's argument to limit adjustments for known and measurable differences to anomalies during the test period would not allow the Commission to accurately simulate the transition period.[410] Ormet states that the Presiding Judge correctly finds that known and measurable differences can occur after the test period; Ormet's reduction in load is a known and measurable difference and must be reflected in the SECA calculation.[411]

3. Commission Determination

319. The Initial Decision generally finds that SECA charges are only for contracts for delivered power that continued into the transition period.[412] As discussed below, we will reverse the findings in the March 10 Partial Decision, April 13 Partial Decision, and Initial Decision with regard to the finding that contracts terminating prior to the transition period are not SECA eligible. In addition, as discussed further below, we will affirm, in part, and reverse, in part, the findings in the Initial Decision with respect to certain discrete claims that test-period load is not reflective of load served during the transition period, and thus, SECA obligations should be adjusted accordingly.

320. As an initial matter, the findings in the March 10 Partial Decision, April 13 Partial Decision and Initial Decision that contracts that do not extend into the transition period should not serve as the basis of SECA charges misperceives the Commission's directives regarding the establishment of SECA charges. The fundamental flaw in this finding is that it improperly transforms the SECA into a transactional charge, when the Commission's prior orders established the SECA as a load-based charge that does not depend on whether an entity transacts across the boundaries that were previously subject to transactional rates resulting in rate pancaking. The Commission stated in the November 2003 Rehearing Order that "[t]he SECA is designed to collect revenue from each zone, or [subzone], in proportion to the benefits that the load within the zone, or

[409] *Id*.

[410] Ormet Brief Opposing Exceptions to the Initial Decision at 17-20.

[411] *Id.* at 13.

[412] Initial Decision, 116 FERC ¶ 63,030 at P 49 (*citing* March 10 Partial Decision, 114 FERC ¶ 63,037 at P 16).

[subzone], will realize when it no longer has to pay pancaked rates for transmission purchased from transmission owners in the other RTO to serve its load."[413] Moreover, the November 2003 Rehearing Order rejected a proposal to use actual usage, stating that using this would "essentially convert the SECA back into a transactional charge for [through-and-out] service, thus recreating the impacts of rate pancaking which we are eliminating."[414] We find that, by recalculating SECA charges using a method other than that directed by the Commission, the Presiding Judge's findings alter the intended results.

321. The Commission's framework for the SECA charges is that the charges are to be established based upon load during the test period,[415] subject to known and measurable changes.[416] Importantly, the Commission has never indicated, and does not find here, that if a contract terminated before the transition period it would result in reduced SECA charges. Load-serving entities are assigned a SECA obligation based on test-period imports that utilized through-and-out service, unless such entities can demonstrate that known and measurable changes have occurred such that they do not benefit due to the elimination of rate pancaking. Whether an entity engages in transactions during the transition period that cross the boundaries that were previously subject to rate pancaking is not dispositive as to whether the entity benefits due to the elimination of regional through-and-out rates. As the Commission has previously found, the elimination of rate pancaking will result in more remote generation becoming economic for import, which will put downward pressure on market prices where the importing load is located, resulting in lower costs for purchases from local generation as well as imports.[417] In fact, few transactions that were active during the test period had terms long enough to extend into the transition period; they would instead likely be replaced by new transactions at beneficial prices reflecting the downward pressure on market prices where the importing load is located due to the elimination of regional through-and-out rates, thereby benefiting due to the elimination of regional through-and-out rates.

322. Therefore, we will overrule the findings in the March 10 Partial Decision, April 13 Partial Decision and Initial Decision that contracts not extending into the transition period are not eligible for SECA charges. Specifically, we will reverse the finding in the March 10 Partial Decision with regard to whether AMP-Ohio can be assessed SECA charges for

---

[413] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 85.

[414] *Id*. P 64 n.117.

[415] *Id.* P 66.

[416] *Id*. P 61; *see also* July 2003 Order, 104 FERC ¶ 61,105 at P 54.

[417] *Id.* P 45.

Contract No. 22 between Aquila and AMP-Ohio. We will also reverse the findings in the April 13 Partial Decision with regard to: (1) whether AMP-Ohio can be assessed SECA charges for Contract Nos. 15 and 25 between AMP-Ohio and DTET; and (2) whether AMP-Ohio can be assessed SECA charges for Contract No. 24 between AMP-Ohio and PSEG. With regard to the findings in the Initial Decision requiring adjustments to SECA obligations for Michigan PPA's terminating contracts, we will likewise reverse the findings in the Initial Decision, and we likewise deny Ormet's request for relief based on its terminating power supply contracts. However, we will affirm the March 10 Partial Decision's and April 13 Partial Decision's findings that AMP-Ohio's Contract No. 22 with Aquila, Contract Nos. 15 and 25 with DTET, and Contract No. 24 with PSEG do not extend into the transition period and, therefore, cannot be used by AMP-Ohio as a basis for asserting shift-to-shipper claims against Aquila, DTET or PSEG.[418] We similarly also will affirm the April 13 Partial Decision's findings that the eight short-term contracts between Dynegy and Constellation, and the contracts between Cinergy and Constellation, do not extend into the transition period and, therefore, cannot be used by Constellation as a basis for asserting shift-to-shipper claims against Dynegy and Cinergy.

323. However, we will affirm the finding in the Initial Decision, though under different reasoning, that Old Dominion's SECA payments to BG&E should be adjusted to remove the test-period MWhs associated with the Ironwood contract. As Old Dominion explains, it will use its own new local generation within its local zone to serve load and will likely not purchase across the PJM-Dominion seam to serve load. Importantly, Old Dominion built a new 500 MW combustion turbine plant within the Dominion zone, which became operational in June 2003 (i.e., the Ironwood contract terminated on May 31, 2003), to replace the 490 MW of firm capacity supplied from the combustion turbine Ironwood plant. Because Old Dominion replaced the Ironwood contract with its own new generator located in the Dominion zone, rather than another purchase that could have benefited due to the elimination of rate pancaking, it is reasonable to conclude that Old Dominion will not benefit due to the elimination of regional through-and-out rates for the load served from its new local generation, and therefore, we will require an adjustment to Old Dominion's SECA obligation for the test-period MWhs associated with the expired Ironwood contract. We will require the PJM transmission owners to submit revised

---

[418] In contrast to our finding that the mere fact that a test-period contract expired before or during the transition period does not demonstrate that a load-serving entity will not benefit due to the elimination of rate pancaking during the transition period, the continuation of a bundled supply contract (which may have taken effect after the test period) during the transition period is relevant for shift-to-shipper purposes because the existence of that contractual arrangement determines which entity had responsibility for delivering power to the load during the transition period and, thus, which entity could realize benefits due to the elimination of rate pancaking.

SECA charges to reflect the adjustment adopted here in the compliance filings ordered below.

324. We also will affirm the findings in the Initial Decision, though under different reasoning, that certain parties' SECA obligations should be adjusted to reflect reductions in load served between the test period and the transition period. Unlike load-serving entities claiming that contracts terminated prior to the transition period and are, thus, not SECA eligible, adjustments to SECA obligations are appropriate for load-serving entities with reduced load during the transition period to accurately align the benefits realized due to the elimination of regional through-and-out rates to the level of load served during the transition period. Where the load served by the load-serving entity during the transition period has been reduced since the test period, or is no longer served by the load-serving entity during the transition period, it is reasonable to conclude that the load-serving entity will not benefit due to the elimination of regional through-and-out rates for the load no longer served. We will, therefore, require the SECA obligations of certain parties to be adjusted, as discussed below.

325. Regarding Ormet, for the 2002 and 2003 test periods, Ormet's load at full operation at its aluminum reduction facility totaled 535 MW (plus approximately 20 MW of transmission losses). During the test period, Ormet had contracts with Cinergy, ComEd, and PECO to supply the 535 MW.[419] Due to a series of economic hardships, however, Ormet's aluminum reduction facility was not at full operation at any time during the transition period, and by December 2004 Ormet's load decreased to approximately 195 MW.[420] By mid-January 2005 Ormet's load declined to approximately 20 MW.[421] On December 20, 2005, Ormet's load dropped to approximately 8 MW due to the permanent closing of one of its facilities. Therefore, based on the Ormet's demonstration that its load during the test period does not accurately reflect its load during the transition period, we will require Ormet's monthly SECA obligation to be adjusted to reflect the reduction between its average monthly coincident-peak load during the applicable test year and its actual coincident-peak load during each month of the transition period. We will require Midwest ISO TOs and the

[419] Ormet states that all of the supply contracts, other than the supply contract with PECO, terminated by their terms on December 31, 2004. Ormet Brief on Exceptions to the Initial Decision at 3-4.

[420] At the end of 2003, Ormet faced significant financial difficulties and on January 30, 2004, Ormet filed for Chapter 11 bankruptcy protection. Ormet Brief on Exceptions to the Initial Decision at 4-5.

[421] Ormet Brief on Exceptions to the Initial Decision at 7.

PJM transmission owners, as applicable, to submit revised SECA charges for the Ormet subzone to reflect the adjustment adopted here in the compliance filings ordered below.

326. Regarding the Initial Decision's findings that Quest's SECA obligation associated with the NOAC contract and deliveries to North Star should be eliminated, we agree, as Quest did not serve these loads during the transition period. The load-serving entity that replaced Quest as the supplier to such loads should be responsible for the SECA charges applicable to such loads, not Quest. However, rather than shifting the Quest SECA obligations for such loads to the new supplier, as AEP, Dayton, and Exelon suggest, the new suppliers should pay the generally applicable zonal SECA charge, applicable to entities without subzone obligations, under section II.B of Schedule 22 of the Midwest ISO tariff for the newly acquired load. We agree with FirstEnergy that Quest's subzonal SECA allocation reflects its own transaction patterns and is not necessarily representative of the transaction patterns of the new load-serving entity. Instead, we find that the generally applicable zonal SECA charge under Schedule 22 is an appropriate proxy for the entity newly taking transmission service to serve the NOAC and North Star loads during the transition period. We will require Midwest ISO TOs and the PJM transmission owners, as applicable, to submit revised SECA charges to reflect the adjustments adopted here in the compliance filings ordered below.

327. Regarding the Initial Decision's finding that CMS Energy's SECA obligation should be adjusted to reflect that it did not serve retail load at the MECS.DECO.CMSZ sink since September 2003, we agree. We find that no party disputed CMS Energy's claim that it had not served retail load at that sink since September 2003. We find it appropriate to require an adjustment to CMS Energy's SECA obligation to reflect this reduction in load between the test period and the transition period. Consistent with our findings above, the entity newly taking transmission service to serve this load during the transition period should pay the generally applicable zonal SECA charge under Schedule 22 of the Midwest ISO tariff for the newly acquired load. We will require Midwest ISO TOs and the PJM transmission owners, as applicable, to submit revised SECA charges to reflect the adjustments adopted here in the compliance filings ordered below.

328. We also agree with the Initial Decision's finding that the Green Mountain subzone SECA obligation should be adjusted to reflect that Green Mountain served no load in Midwest ISO between January 2006 and March 2006. As we find below, the entity that took transmission service under the Midwest ISO tariff during the transition period to serve the load in the Green Mountain subzone on behalf of Green Mountain should pay the Green Mountain subzone SECA. Consistent with our findings above, once Green Mountain no longer served load in Midwest ISO in January 2006, the entity newly taking transmission service to serve this load during the remainder of the transition period should pay the generally applicable zonal SECA charge under Schedule 22 of the Midwest ISO tariff. We will require Midwest ISO TOs and the PJM transmission

owners, as applicable, to submit revised SECA charges to reflect the adjustments adopted here in the compliance filings ordered below.

329. Finally, we will deny Michigan PPA's request for summary disposition for claimed known and measurable differences with respect to imports from AEP in January and February of 2002. Michigan PPA has not provided any historical information regarding the outage and maintenance histories for the two generating units that form the basis for this known and measurable difference claim or historical information regarding the outage and maintenance histories of other units. Nor has it provided historical information regarding its total imports and purchases of replacement power. Without such information, we are unable to assess whether its imports in January and February of 2002 that are the subject of this known and measurable difference claim are truly anomalous.

K. Fixed Versus Per-Unit SECA Charge

1. Initial Decision

330. Based on the testimony of Midwest ISO TOs' witness Mr. Heintz, the Commission provided guidance on how the SECA mechanism should be developed. Under Mr. Heintz' 2002 proposal, the SECA would be based on actual billing units, which is a type of usage charge. In the compliance filings, Midwest ISO TOs and the PJM Transmission owners changed the SECA mechanism from a usage charge to a fixed charge. Under a usage charge, the SECA would be assessed on actual monthly billing units. With the proposed fixed charges, the SECA is a fixed demand-type charge, which is not based on current usage.[422] Mr. Heintz stated that the Midwest ISO stakeholders conducted a meeting at which participants determined that they wanted a stated charge.[423]

331. The Initial Decision states that Ormet proposes an alternative mechanism in which SECA rates would be developed in the traditional manner – by dividing test-year revenues by test-year load. Ormet proposes that the resulting per-unit SECA rate be applied to actual monthly billing determinants for the transition period. Ormet's proposed SECA is a usage rate.[424]

---

[422] Initial Decision, 116 FERC ¶ 63,030 at P 224.

[423] We note that the proposed subzonal charges in PJM, while calculated and assessed differently than Midwest ISO TOs' proposed subzonal charges, are similarly designed to collect the test-period lost revenue without reflecting changes in load between the test period and transition period.

[424] *Id.* P 220.

332. The Initial Decision finds that the record does not support the proposition that the majority of stakeholders supported the change from a usage charge to a stated rate.[425]

333. The Initial Decision finds that the fixed SECA charge proposals filed by Midwest ISO TOs and the PJM transmission owners do not follow the principles of cost causation. The Initial Decision states that:

> [t]he Commission clearly intended that the SECA mechanism allocate costs to load in proportion to the benefits they receive from the elimination of [regional through-and-out rates]. The compliance filings in this proceeding do not achieve this objective. For example…by developing a fixed charge rather than a usage charge, the SECAs are designed to guarantee that SECA revenues during the transition period equal [through-and-out] revenues from the historical period. With all of the changes in the electric industry during the time of these proceedings, an assumption that load will remain constant is a faulty assumption. The only way to assure that costs associated with providing transmission service are equitably paid by those that receive the benefits of the elimination of [through-and-out] rates is to adopt a non-by-passable usage charge. As shown by Ormet, assessing a demand-type SECA, which is based on historical data, inequitably assigns to Ormet costs for transmission services in the transition period for which it did not benefit.[426]

334. The Initial Decision rejects arguments that revenue neutrality means that the transmission owners are guaranteed recovery of 100 percent of their through-and-out revenues. The Initial Decision holds that, since cost-based SECA charges are replacing cost-based regional through-and-out rates, revenue neutrality can only mean that transmission owners are provided a reasonable opportunity to recover their lost revenues through the SECA mechanism. Although the Commission's intent was for the SECA revenues to approximate the level of lost revenues, the Initial Decision states that it would be merely coincidental if they were identical.[427]

335. Midwest ISO TOs contended that a shift from a stated rate to a usage charge will result in most of the load-serving entities that they serve paying more in SECA revenues than they would pay under Midwest ISO TOs' proposal. The Initial Decision determines that, to the extent that a load-serving entity transmitted more energy over the Midwest

---

[425] *Id.* P 225.

[426] *Id.* P 230.

[427] *Id.* P 237-38.

ISO-PJM seam during the transition period than during the test period, that load-serving entity should be responsible for increased transmission charges; conversely, to the extent that a load-serving entity's cross-seam usage decreased, its transmission costs should also decrease. The Initial Decision states that this is consistent with the Commission's goal that increased growth in transmission as a result of the elimination of regional through-and-out rates may result in increased costs. The Initial Decision adds that a properly-designed SECA will provide the opportunity for transmission owners to recover such costs.[428]

336. Thus, the Initial Decision finds that the SECA mechanisms proposed by Midwest ISO TOs and the PJM transmission owners do not comply with the Commission's directives and should be rejected. However, the Initial Decision finds that Ormet's SECA proposal satisfies the Commission's goals for developing a transitional mechanism. The Initial Decision cites the Ormet proposal's use of North American Electric Reliability Corporation tag data and development of lost through-and-out revenues using 2003 data, the data for the most recent twelve months at the time of the first compliance filing, with adjustments for known and measurable differences, to most closely reflect future trading patterns. In addition, the Initial Decision notes that Ormet's proposal will recover revenues from customers in proportion to the benefits that such customers receive due to the elimination of regional through-and-out rates through a non-bypassable usage charge on load.[429]

2. Brief on Exceptions

337. Midwest ISO TOs argue that the fixed monthly subzone charge more closely aligns costs and benefits and limits cost shifts, as the Commission directed, and provides certainty as to payments and collection. They state that the Commission has considered and approved similar fixed charges in other contexts.[430] In addition, before implementing

---

[428] *Id.* P 239.

[429] *Id.* P 240.

[430] For example, Midwest ISO TOs cite Commission orders accepting a service agreement with a customer charge. They argue that a fixed monthly charge also is similar to the "direct bills" that the Commission approved as part of Order No. 636's restructuring of interstate natural gas pipelines, arguing that in such cases the Commission expressly found that a monthly fixed charge for those costs would be just and reasonable and would better allocate the short-term transitional cost to the party responsible for the costs in the prior regime. Midwest ISO TOs Brief on Exceptions to the Initial Decision at 43, n.145.

this charge, they state that it was discussed with various Midwest ISO stakeholders who stated that they preferred this approach.[431]

338. Midwest ISO TOs argue that the Initial Decision does not address their claims that the stated fixed monthly subzone charges eliminate cost shifts and are consistent with the Commission's orders regarding the use of subzones to recover lost revenues. They maintain that, consistent with the Commission's directives, each subzone's charges are based on the MWhs that sank in that subzone during the test period. Thus, they assert that each subzone's fixed charge is based only on that subzone's transactions and accurately reflects each subzone's obligations by aligning the subzone's benefits due to the elimination of regional through-and-out rates with the lost revenues owed. Midwest ISO TOs contend that the fixed monthly charge provides for the stated amount to be collected, which helps to prevent over and under collections of the lost revenues.[432]

339. With respect to the Presiding Judge's determination that they failed to demonstrate why a change from a usage charge to a fixed charge was required, Midwest ISO TOs argue that there is nothing in the Commission's orders prescribing the SECA methodology that suggests that a fixed charge would not be appropriate. They contend that Commission precedent establishes that rates proposed in a compliance filing need only be just and reasonable and not unduly discriminatory or preferential and that they need be neither perfect nor even the most desirable. In this case, Midwest ISO TOs maintain that the entities that would pay most of the SECA charges in Midwest ISO stated that they preferred the reasonable method of collecting SECA obligations via a fixed monthly charge. Further, they state that they justified the use of a stated rate in the testimony of Mr. Heintz.[433]

340. Midwest ISO TOs further argue that there are problems with a usage charge. With respect to the Presiding Judge's emphasis that the SECA is designed to keep transmission owners revenue neutral, Midwest ISO TOs assert that under a usage charge, which produces more revenues as load grows, the transmission owners would receive more revenues than they would under a fixed monthly charge. They also contend that the Initial Decision demonstrates a fundamental misunderstanding of the SECA methodology when it states that "to the extent that [an] load-serving entity transmitted more energy over the Midwest ISO-PJM seam during the transition period than during the test period, that load-serving entity should be responsible for increased transmission charges" and

[431] *Id.* at 43.

[432] *Id.* at 44.

[433] *Id.* at 44-45.

vice versa.[434] Midwest ISO TOs contend that a usage charge would be a non-bypassable charge to load. Therefore, they conclude that a usage charge will not result in only those using the seam more, paying more. Rather, those with more load would pay more, regardless of transactions across the seam.[435]

3. **Briefs Opposing Exceptions**

341. AEP, Dayton, and Exelon argue that, if the Initial Decision intends to reject fixed SECA charges, the Commission must address this issue on a generic basis with respect to all non-settling parties. AEP, Dayton, and Exelon state that they are not opposed to the development of SECA rates in the form of fixed monthly charges or in the form of monthly unit charges that are developed based on load during the test period and assessed to billing determinants for load during the transition period, but they object to rate design approaches that are incompatible between the two RTOs. If the Commission requires that within PJM SECA charges are to be developed as unit charges reflecting load during the test period and that the charges are to be applied to billing determinants during the transition period, they argue that this approach should apply within Midwest ISO as well.[436]

342. CMS Energy argues that Midwest ISO TOs' apparent reliance on one stakeholder meeting, which may not have included any PJM customers and where some of Midwest ISO's customers may have expressed a desire for stated rates as the justification for choosing the proposed form of SECA collection, cannot rationalize a decision that compels parties to pay large charges that bear no connection to their actions. Ormet and Green Mountain argue that it is not dispositive whether a majority of stakeholders wanted a stated rate. Ormet argues that, as the Initial Decision finds, the record does not support the proposition that a majority of stakeholders wanted a stated rate. According to Ormet, Mr. Heintz stated that, as far as he knew, no PJM stakeholders were at the stakeholder meeting that he relied upon, and Dr. Henderson stated that he had only heard about the stakeholder meeting from Mr. Heintz. Green Mountain states that Mr. Heintz admitted that he did not mean to imply that Green Mountain had expressed such a preference at any point. Further, Ormet and Green Mountain argue that the majority of Midwest ISO

---

[434] *Id.* at 46 (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 239).

[435] *Id.* at 45-46.

[436] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 22-23.

stakeholders at the meeting may not vote to allow transmission owners to charge unjust and unreasonable rates or subject entities to unlawful retroactive ratemaking.[437]

343. CMS Energy argues that, by locking in the revenues from the test period without providing any means for a load-serving entity to reduce its exposure, Midwest ISO TOs transformed the load-based surcharge envisioned by the Commission into an inescapable fee that is only coincidentally related to the benefits that a load-serving entity may have received during the transition period. None of Midwest ISO TOs' witnesses presented a convincing explanation as to how their approach, instead of an approach based on the actions taken by load-serving entities, comported with cost-causation principles.[438] Thus, CMS Energy argues, it would be merely a coincidence if a customer were to pay a SECA charge that is proportionate to the benefits that the customer received due to the elimination of regional through-and-out rates.[439]

344. Green Mountain states that the Initial Decision correctly finds that Midwest ISO TOs' proposed rate design violates the principle of cost causation. Green Mountain disputes Midwest ISO TOs' assertion that the fixed charge more closely aligns costs and benefits. According to Green Mountain, a flat monthly charge assesses each entity the same amount each month, regardless of the extent to which it benefitted from the facilities whose costs are supposedly being collected through the rate. Green Mountain asserts that this is shown by the fact that Midwest ISO TOs proposed to charge Green Mountain more than $2.2 million per month during a period when it conducted no activities in the combined region and, therefore, clearly derived no benefit from Midwest ISO or PJM transmission facilities.[440]

345. Green Mountain disputes Midwest ISO TOs' claim that a fixed charge prevents cost shifting. Green Mountain argues that the fixed charge does not prevent cost shifting but instead prevents the proper allocation of cost responsibility in the first place. It states that properly allocating cost responsibility to those entities that actually cause the costs to be incurred is the foundation of the principle of cost causation. By locking in a flat charge irrespective of the level of service, Green Mountain maintains that Midwest ISO TOs' flat charge assigns cost responsibility to entities, such as Green Mountain, that

---

[437] Ormet Brief Opposing Exceptions to the Initial Decision at 52-53; Green Mountain Brief Opposing Exceptions to the Initial Decision at 22.

[438] CMS Energy Brief Opposing Exceptions to the Initial Decision at 30.

[439] *Id.* at 30-31.

[440] Green Mountain Brief Opposing Exceptions to the Initial Decision at 21.

because they take no service are not responsible for any costs. Green Mountain concludes that this results in impermissible cost shifting.[441]

346. Ormet disputes AEP, Dayton, and Exelon's claim that the Commission has already approved the rate design that they propose in their compliance filings. Ormet argues that the November 2003 Rehearing Order addressed a proposed rate design that differs substantially from the rate design proposed in the compliance filings. According to Ormet, that order involved a proposal using traditional rate design, where a per-unit rate was calculated by dividing test-period revenues by test-period load and then that per-unit rate was to be applied to future billing determinants. Ormet maintains that the Commission's orders in this proceeding contemplated both a traditional ratemaking methodology and adjustments for known and measurable differences, and the compliance filings have met neither criterion.[442]

347. Ormet argues that Midwest ISO TOs' argument also assumes that the SECA is meant to recover 100 percent of test-year revenues rather than the revenues that would have been collected through regional through-and-out rates during the transition period but for the elimination of that rate. In fact, states Ormet, use of a combination of North American Electric Reliability Corporation tag data and the traditional rate design could result in revenues that are higher or lower than those received during the test period, depending upon the growth or reduction in the size of load-serving entities that imported load during the test period. If the revenue-neutral goal is to collect revenues that would have been collected but for the elimination of regional through-and-out rates, then the increased revenues associated with load growth (or decreased revenues associated with load reduction) are appropriate, as recognized by the Commission.[443]

4. <u>Commission Determination</u>

348. We will reverse the Initial Decision's rejection of the fixed subzonal SECA charges that were proposed in the compliance filings by Midwest ISO TOs and the PJM transmission owners. While the Initial Decision is correct that the SECA as originally proposed by Midwest ISO TOs and former members of the Alliance RTO, and adopted by the Commission in the November 2003 Rehearing Order, was designed as a usage charge, in their SECA compliance filings, the transmission owners in each RTO have voluntarily designed their subzonal SECA charges as fixed charges that recover test-

---

[441] *Id.* at 21-22.

[442] Ormet Brief Opposing Exceptions to the Initial Decision at 42-44 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 48).

[443] *Id.* at 54 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 50).

period revenues and do not vary with the level of the load-serving entity's load. The Initial Decision appropriately finds that such fixed charges would result in unjust and unreasonable charges if certain entities experienced reductions in the loads that they serve since the test periods and had not been given an opportunity to make adjustments. However, rather than order changes to all of the non-settled SECA charges to reflect a traditional usage charge, which as Midwest ISO TOs note, would generally result in increased charges for customers, as discussed above, we have ordered adjustments to the subzonal SECA charges for these entities to reflect their load reductions. In light of these adjustments, we find it unnecessary to eliminate the use of the proposed fixed subzonal SECA charges for all load-serving entities in order to ensure just and reasonable SECA charges.

L. Relationship of SECA Charges to Existing Transaction Charges

1. Initial Decision

349. The Initial Decision states that FirstEnergy's contention that existing transaction charges should be capped at the amount of a customer's SECA obligation is incorrect because the Commission has not held that such a cap should be employed. Moreover, the Initial Decision states that "[i]t is clear that the Commission only intended this mechanism to apply to [load-serving entities] with [existing transactions] which would pay [through-and-out rates] and SECA charges. The adjustment proposed would be to the SECAs and not to [through-and-out rates] for [existing transactions]."[444] In support of this finding, the Initial Decision cites to the November 2003 Rehearing Order where the Commission stated that "for existing transactions, we will allow the existing [regional through-and-out] rate design to remain in effect during the transition period."[445] Furthermore, the November 2003 Rehearing Order stated that "we will not eliminate the [regional through-and-out rates] for existing transactions that sink in the combined region…."[446] The Initial Decision also notes that the Commission stated that "any transmission customer that currently has a long-term firm transmission reservation effective before April 1, 2004, including those that are not [load-serving] entities will continue to pay the [regional through-and-out rate], thus limiting the amount of lost revenues to be recovered from load."[447] Thus, the Initial Decision finds that the Commission clearly stated that customers under existing transactions would continue to

[444] Initial Decision, 116 FERC ¶ 63,030 at P 263.

[445] *Id.* (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 9).

[446] *Id.* (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 14).

[447] *Id.* (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

pay regional through-and-out rates. To that end, the Initial Decision finds that the Commission recognized that load-serving entities paying regional through-and-out rates for existing transactions may be assessed disproportionate SECA charges and stated:

> [s]imilarly, we recognize that a [load-serving entity] with existing [through-and-out] service reservations that will continue into the transition period will continue to pay [regional through-and-out rates]. If such [a] [load-serving entity] does not have its own [subzonal] SECA, the SECA may assess such [load-serving entity] a disproportionate share of lost [regional through-and-out] revenues. Therefore, we will allow such [load-serving entities] with existing transmission arrangements that continue into the transition period to demonstrate to the Commission *the extent of disproportionate impact of paying both the [regional through-and-out rate] and the SECA* and propose an adjustment to its SECA obligation proportional to the [regional through-and-out] charges it will continue to incur under the existing transmission arrangements.[448]

350. Furthermore, the Initial Decision finds that FirstEnergy's arguments attempt to expand the scope of this mechanism to limit the transmission owners' charges for existing transactions and are, thus, contrary to the Commission's orders. The Initial Decision states that the Commission's pronouncement would adjust the SECA in proportion to the through-and-out payments that the entity incurs, exactly the opposite of what FirstEnergy proposes, which is to limit the existing transactions' regional through-and-out rates to the SECA obligations.

351. In addition, the Initial Decision finds that the June 2005 Order also does not support FirstEnergy's contentions. The Initial Decision states that the June 2005 Order required billing procedures for crediting existing transaction revenues and did not limit existing transactions' through-and-out payments. Moreover, the Initial Decision states that the June 2005 Order did not establish a cap on the amount of existing transactions' through-and-out charges a customer could be billed and it most definitely did not transform existing transactions' credits into refundable amounts, as FirstEnergy asserts. The Presiding Judge states that "[s]uch credits exist only to the extent that a [through-and–out] [existing transaction's] payment exceeds a SECA obligation in a particular month and the [existing transaction's] payment is carried over as a credit against the SECA for the following month."[449] The Initial Decision states that "although it may not be completely accurate to say that any unused credits expire at the end of the transition

---

[448] *Id.* (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45, n.94 (emphasis added by Presiding Judge)).

[449] *Id.* P 265 (*citing* June 2005 Order, 111 FERC ¶ 61,409 at P 41).

period, the same result occurs because there is no longer a SECA obligation for [existing transaction] credits to offset. FirstEnergy's arguments that these credits should not 'expire' are rejected since the Commission only intended the credits to remedy the billing disparities."[450] Moreover, the Initial Decision states that from the Commission's language one can determine that regional through-and-out rates for existing transactions and SECA payments were two distinct types of charges for separate transactions. Thus, the Initial Decision finds that the amount that a customer can be billed for existing transactions' regional through-and-out rates should not be capped at a customer's SECA obligation.[451]

352. Finally, the Initial Decision states that Midwest ISO's and PJM's proposed crediting process is reasonable. Specifically, the Initial Decision states that Schedule 21 of the Midwest ISO tariff and Attachment X of the PJM tariff provide for customers to receive credits for regional through-and-out rates paid for existing transactions. In addition, the Initial Decision finds that the record indicates that Midwest ISO and PJM also carried excess existing transactions credits forward to offset SECA payments in future months. As such, the Initial Decision states that the fact that the credits expire or are not refunded at the end of the transition period is irrelevant.

2. **Brief on Exceptions**

353. FirstEnergy excepts to the Initial Decision's finding that FirstEnergy is not entitled to a credit for the $20 million in through-and-out charges for existing transactions that it paid in excess of its SECA obligation during the transition period. FirstEnergy takes the position that the through-and-out charges assessed by Midwest ISO to its affiliated merchant, FirstEnergy Solutions, under existing transactions should be capped at the SECA obligation as assigned to FirstEnergy Solutions under the PJM tariff.[452] FirstEnergy contends that its position is justified by the Commission's directive that the SECA mechanism is to hold utilities "revenue neutral" but is not intended to provide utilities with revenues greater than their lost through-and-out revenues.[453] FirstEnergy argues that the Initial Decision errs by failing to limit FirstEnergy's through-and-out charges for existing transactions to the amount of its SECA obligation and permitting

---

[450] *Id.* n.78 (*referring to* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45 n.94).

[451] The Presiding Judge finds that no refunds are due for excess credits that remain after the transition period, and thus, no associated interest. *Id.* n.80.

[452] FirstEnergy Brief on Exceptions to the Initial Decision at 14.

[453] *Id.*

Midwest ISO TOs to recover greater revenues from FirstEnergy Solutions than the revenues necessary to compensate them for their lost through-and-out revenues.

354. FirstEnergy explains that, under the transitional SECA rate mechanism, PJM assigned to FirstEnergy Solutions, and it was obligated to pay, a SECA during the transition period in an amount sufficient to ensure that Midwest ISO TOs would recover their lost through-and-out revenues and that FirstEnergy Solutions also was obligated to pay through-and-out charges for its existing transactions. FirstEnergy argues that it should be able to demonstrate the impact of paying both the through-and-out charges and the SECA and have its through-and-out charges adjusted so that they are equal to its SECA obligation. FirstEnergy states that, since FirstEnergy Solutions' through-and-out charges for existing transactions exceeded its SECA during the transition period, it had an existing transaction credit; however, Midwest ISO and Midwest ISO TOs claim that the existing transaction credit expired at the end of the transition period and that Midwest ISO TOs are entitled to the amount that they received as a result of FirstEnergy Solutions' excess through-and-out charges.

355. FirstEnergy points out that the June 2005 Order required Midwest ISO and PJM to credit load-serving entities, like FirstEnergy, for the amount by which their through-and-out charges exceeded their SECA obligations each month, thereby assuring that a load-serving entity's through-and-out charges would be equal to its SECA obligation in each month of the transition period. FirstEnergy states that, therefore, its arguments are not contrary to, but rather consistent with, the Commission's orders. Further, FirstEnergy argues that its existing transaction credit should not expire at the end of the transition period and that there is no support for the Initial Decision's finding that such credits exist only to the extent that a through-and-out existing transaction payment is carried over as a credit against the SECA for the following month or that the unused credits expire at the end of the transition period. FirstEnergy states that the Commission should find that it is entitled to its unused existing transaction credit at the end of the transition period in the form of a refund.

3. Briefs Opposing Exceptions

356. Midwest ISO TOs state that the Initial Decision appropriately finds that an entity's SECA obligation should not serve as a cap on that entity's obligation for through-and-out charges associated with existing transactions and that an entity is not entitled to a refund for the amount by which its through-and-out charges exceeded its SECA obligation, as FirstEnergy claims. Midwest ISO TOs argue that the Commission did not eliminate regional through-and-out rates for existing transactions and that the Commission should affirm the Initial Decision's finding that the amount that a customer can be billed for existing transactions' regional through-and-out rates should not be capped at the customer's SECA obligation. Midwest ISO TOs state that the regional through-and-out rate was left in place for existing transactions, and an entity's obligation to pay the filed regional through-and-out rate for existing transactions did not cease at the point where

the entity had paid regional through-and-out rates in an amount equivalent to its separate SECA obligations.

357. Midwest ISO TOs state that the Commission required credits against SECA obligations and that the credit adjusted the SECA obligations to account for the continuation of certain regional through-and-out rates by the Commission. Midwest ISO TOs argue that the crediting mechanism is one-way: the credit only adjusts the SECA obligations for a given entity, not the entity's regional through-and-out rate obligations for existing transactions. Midwest ISO TOs state that FirstEnergy's arguments are meritless and that the Presiding Judge correctly finds that regional through-and-out rates for existing transactions and SECA payments were two distinct types of charges for separate transactions and that the amount a customer can be billed for existing transactions' regional through-and-out rates should not be capped at a customer's SECA obligation.

358. Midwest ISO TOs also state that they are entitled to the revenues associated with the regional through-and-out rates as the through-and-out charges were collected as compensation for use of the transmission owners' systems during the transition period. They further state that, when the Commission directed the continued assessment of regional through-and-out rates on existing transactions, it clearly intended the transmission provider to collect such through-and-out revenues. Further, Midwest ISO TOs state that the through-and-out revenues associated with existing transactions that were not applied as credits against SECA charges are not simply leftover amounts. Rather, existing transaction through-and-out revenues are separate and apart from "lost revenues" associated with the elimination of regional through-and-out rates and that transmission providers are entitled to compensation for existing transactions on their transmission systems. Midwest ISO TOs also state that they reduced transmission rates charged under the Midwest ISO tariff as a result of the through-and-out revenues from existing transactions; therefore, transmission customers saw reduced transmission rates as a result of the existing transaction revenues. Midwest ISO TOs argue that they simply collected revenues under the filed rate that was in effect when FirstEnergy entered into its existing transactions and, significantly, that remained in effect during the transition period. Midwest ISO TOs argue that crediting through-and-out revenues back to the entity that was required to pay that regional through-and-out rate would result in a violation of the filed rate doctrine.

359. Midwest ISO TOs state that the Presiding Judge correctly finds that the fact that credits expire or are not refunded at the end of the transition period is irrelevant. Midwest ISO TOs point out that, after the conclusion of the transition period, both regional through-and-out rates for existing transactions and the SECA obligations that would receive a credit in proportion to the regional through-and-out rates paid for existing transactions ended. Midwest ISO TOs argue that credits associated with regional through-and-out rates for existing transactions may be used only to offset a SECA

obligation and that, after the transition period, there are no SECA obligations to be offset by any remaining credits. Therefore, no refunds are due for excess credits that remain after the transition period.

360. AEP, Dayton, and Exelon also state that FirstEnergy's arguments should be rejected because there is nothing in the Commission's orders which caps a transmission customer's obligation to pay regional through-and-out rates under existing transactions during the transition period.

4. **Commission Determination**

361. We will affirm the Initial Decision, for the reasons stated in the Initial Decision; FirstEnergy's SECA obligation should not serve as a cap for through-and-out charges associated with existing transactions (i.e., reservations for requests for service made prior to November 17, 2003, for service commencing before April 1, 2004). We agree that FirstEnergy is not entitled to a refund for the amount that FirstEnergy's through-and-out charges for existing transactions exceed its SECA obligations. We find that the Initial Decision properly decides the existing transactions issue, and FirstEnergy's arguments on exception fail to persuade us that the Initial Decision errs.

362. While FirstEnergy argues that the Initial Decision errs by failing to limit FirstEnergy's through-and-out charges for existing transactions to the amount of its SECA obligation, FirstEnergy has provided no evidence to indicate that the Commission's prior orders require Midwest ISO TOs to limit (i.e., cap) through-and-out charges for existing transactions to FirstEnergy's SECA obligation. As the Initial Decision correctly points out, the Commission explicitly stated that "for existing transactions, we will allow the existing [regional through-and-out] rate design to remain in effect during the transition period"[454] and that "any transmission customer that currently has a long-term firm transmission reservation effective before April 1, 2004, including those that are not [load-serving] entities will continue to pay the [regional through-and-out rate]."[455]

363. The Initial Decision correctly recognizes that the Commission provided that load-serving entities with existing transactions that continue into the transition period, and continue to pay regional through-and-out rates, should receive adjustments to their SECA obligations necessary to prevent double recovery for such transmission. Specifically, as the Initial Decision states, the Commission recognized that load-serving entities may be

[454] Initial Decision, 116 FERC ¶ 63,030 at P 263 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 9).

[455] *Id*. (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

assessed disproportionate SECA charges, and the Commission allowed load-serving entities "to demonstrate to the Commission *the extent of disproportionate impact of paying both the [regional through-and-out rate] and the SECA* and propose an adjustment to its SECA obligation proportional to the [regional through-and-out] charges it will continue to incur under the existing transmission arrangements."[456]

364. Thus, the Commission required credits against SECA obligations for existing transaction regional through-and-out rates paid. However, to the extent that a load-serving entity's existing transaction regional through-and-out rates exceed its SECA charges, the difference does not reflect a double payment and requires no adjustment to prevent the double charges that concerned the Commission. Thus, we agree with the Initial Decision that such credits only exist to the extent that a load-serving entity's existing transaction through-and-out payment, plus existing transaction through-and-out payments carried over as a credit from a prior month, does not exceed its SECA obligation in a particular month.[457] We disagree with FirstEnergy's suggestion that failing to limit through-and-out charges for existing transactions to the amount of its SECA charges will permit Midwest ISO TOs to recover greater revenues than the revenues necessary to compensate for lost through-and-out revenues. The SECA mechanism is designed to provide the transmission owners with an opportunity to recover their lost through-and-out revenues, no more and no less. While certain entities may pay more in regional through-and-out rate obligations than they would have paid in SECA obligations, other entities may pay less than their SECA obligations to the extent that they have supported adjustments for known and measureable differences.

365. In sum, we agree with the Initial Decision that regional through-and-out rates for existing transactions and SECA charges are distinct and separate charges, and the Commission orders do not require existing transaction regional through-and-out rates to be capped at the SECA obligation. Therefore, as discussed above, we will affirm the Initial Decision.

M. Shift-to-Shipper Claims

366. In the November 2003 Rehearing Order, the Commission recognized that, in certain instances, the benefits of the elimination of regional through-and-out rates would not accrue to the load-serving entity but rather to the load-serving entity's shipper who had traditionally paid the charges for through-and-out service pursuant to the relevant

---

[456] *Id.* (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45 n.94 (emphasis added by Presiding Judge)).

[457] *Id*. P 265 (*citing* June 2005 Order, 111 FERC ¶ 61,409 at P 41).

contract for delivered power.[458] In addition to paying the SECA, load-serving entities with bundled delivery contracts extending into the transition period would also be paying regional through-and-out rates, which remained embedded in the long-term contract price even after the elimination of these rates. To prevent this double payment, the Commission provided a "shift-to-shipper" mechanism, allowing a load-serving entity to shift its SECA liability to its shipper. The Commission stated:

> as part of the compliance filing process, we will allow [load-serving entities] under existing contracts for delivered power that continue into the transition period to demonstrate that the supplier is the shipper for such transactions and to propose that the supplier be required to pay the SECA for that portion of the [load-serving entity's] load served by the contract.[459]

367. Several parties filed shift-to-shipper claims, many of which were subsequently settled. The Initial Decision's findings regarding the remaining claims are discussed below.

1. <u>Michigan SCPA's Claim Against CCG</u>

a. <u>Initial Decision</u>

368. The Initial Decision finds that Michigan SCPA made the requisite showing to shift its SECA liability under its long-term contract with CCG. This conclusion rests upon several findings, including, among others, that the agreement between CCG and Michigan SCPA constitutes an existing contract for delivered power that continued into the transition period, that CCG is the supplier under the terms of that agreement, and that the chain of supply for delivered power effectively stops with the load-serving entity's (i.e., Michigan SCPA's) contractual counterparty (i.e., CCG) for the purposes of a shift-to-shipper claim.[460]

---

[458] November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45.

[459] *Id.*

[460] Initial Decision, 116 FERC ¶ 63,030 at P 423-428. The Initial Decision further finds that CCG failed to defend against Michigan SCPA's shift-to-shipper claim by asserting a successful "ripple" claim that would have shifted (once again) Michigan SCPA's SECA liability to an upstream supplier shown to be the actual beneficiary of the elimination of regional through-and-out rates. In addition, while the Presiding Judge notes that Midwest ISO TOs are not entitled to collect SECA charges for the recovery of revenues for transactions associated with the Midwest ISO day-ahead and real-time energy markets (because they do not cross over the Midwest ISO-PJM seam and,

(continued…)

369. The Initial Decision further finds, however, that the amount Michigan SCPA sought to shift should be recalculated and then reduced by 21.8 percent. Citing evidence showing that Michigan SCPA sold 57,354 MWh of power to third parties in 2005, the Presiding Judge states that Michigan SCPA did not need all 262,800 MWh of power delivered by CCG to serve Michigan SCPA's load.[461]

b. Briefs on Exceptions

370. Michigan SCPA takes exception to the Initial Decision's finding that its shift-to-shipper claim of $884,355 should be reduced by 21.8 percent. Michigan SCPA argues that the finding is erroneously based on transactions that occurred in 2005, rather than test years 2002 and 2003, and inappropriately requires Michigan SCPA to explain that it needed, rather than used, the power delivered by CCG to serve its load. Michigan SCPA states that no such requirements are articulated in the November 2003 Rehearing Order and that no other party was required to explain or faulted for the economics of its power supply decisions. In any case, Michigan SCPA asserts that record evidence establishes that increased output from its own generation corresponds to its increased sales of excess generation to third parties in 2005 and that there is no evidence establishing that Michigan SCPA sold power purchased from CCG to third parties.

371. Constellation takes exception to the Initial Decision's finding that any Michigan load-serving entity's SECA liability, including that of Michigan SCPA, should be shifted to CCG. Constellation asserts that, by accepting Michigan SCPA's and other Michigan load-serving entities' arguments, the Initial Decision conflates the terms "supplier" and "shipper" and fails to require any Michigan load-serving entity to demonstrate that its supplier was the shipper. Under this interpretation, contends Constellation, the load-serving entity's contractual counterparty is assumed to be both the supplier and the shipper; the load-serving entity is relieved of any burden to prove it. Indeed, Constellation asserts that, by stating that CCG is the more appropriate party to file upstream shift-to-shipper claims, the Initial Decision places the burden of proof on

therefore, would not have been subjected to rate pancaking through regional through-and-out rates), the judge concludes that CCG did not demonstrate that it sourced the power to Michigan SCPA from the Midwest ISO markets. *Id.* P 427, 437.

[461] The Presiding Judge notes that the shift provision in Paragraph 45 of the November 2003 Rehearing Order applies only to power used to serve load. *Id.* P 435.

CCG.[462] Moreover, Constellation argues that the Initial Decision erroneously relies upon a limited interpretation of Paragraph 45 of the November 2003 Rehearing Order, which leaves only a load-serving entity's contractual counterparty responsible for SECA liability. According to Constellation, Paragraph 45 of the November 2003 Rehearing Order allows for the possibility of shifting SECA liability to any party in the chain of supply that might have benefited due to the elimination of regional through-and-out rates.

372. With specific regard to the amount Michigan SCPA seeks to shift, Constellation argues that Michigan SCPA's calculation was based exclusively on test-period data without adjustments for changes that occurred during the transition period.[463] Moreover, Constellation notes that the Initial Decision indicates that the 21.8 percent reduction should be made to Michigan SCPA's total SECA obligation of $995,518, rather than the $884,355 in SECA charges that Michigan SCPA proposed to shift.[464]

c. **Briefs Opposing Exceptions**

373. In response to Constellation, Michigan SCPA argues that the Commission's order does not require a party pursuing a shift-to-shipper claim to demonstrate that its supplier actually benefited due to the elimination of regional through-and-out rates. Michigan SCPA states that the Commission refers to "benefits" in the order only as part of a generalized discussion in support of its decision to eliminate regional through-and-out rates, not as a specific element of a SECA claim.

374. In response to Michigan SCPA's argument that the Initial Decision improperly requires Michigan SCPA to support its economic decisions, Constellation states that the Initial Decision finds that Michigan SCPA failed to submit evidence supporting its contention that the third-party sales at issue originated from its own generation units. Constellation further argues that the Initial Decision properly uses 2005 data to reduce Michigan SCPA's shift-to-shipper adjustment because the Commission's order directed

---

[462] Constellation Brief on Exceptions to the Initial Decision at 33-34 (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 433 ("to require that M[ichigan]SCPA file its shift claim against an upstream supplier with whom it had no contract is both inefficient and unfair. With superior knowledge of its own contractual arrangements, CCG is the more appropriate party to file these upstream shift claims.")).

[463] For example, Constellation states that Michigan SCPA's purchases from third-party suppliers were reduced dramatically between the test period and the transition period, and Michigan SCPA purchased a substantial amount of power from the Midwest ISO day-ahead and real-time energy markets in 2005.

[464] Initial Decision, 116 FERC ¶ 63,030 at P 438.

that SECA calculations be adjusted (using test-period data with adjustments for known and measurable differences) to most closely reflect future trading patterns.

d. Commission Determination

375. We find that the Initial Decision properly finds that Michigan SCPA may shift a portion of its SECA liability to CCG. CCG is the only supplier in the chain of supply that has a contractual obligation to deliver power to Michigan SCPA.[465] If, in turn, CCG has its own supplier or suppliers upon whom it relies to meet its contractual obligations, that is a matter between CCG and its supplier or suppliers; it is irrelevant to Michigan SCPA's shift-to-shipper claim. Accordingly, we reject Constellation's argument that Paragraph 45 of the November 2003 Rehearing Order allows a load-serving entity to shift its SECA liability to *any* supplier in the chain of supply from source to sink. That argument ignores an express requirement in Paragraph 45, namely, that a load-serving entity have an *existing contract for delivered power* with the supplier targeted for a shift-to-shipper claim.

376. We further note, contrary to Constellation's argument, that Paragraph 45 does not require a load-serving entity to show that the supplier to whom it seeks to shift its SECA liability benefited due to the elimination of regional through-and-out rates. The Commission eliminated regional through-and-out rates in the hope of establishing a more efficient and competitive electricity market in the combined region. The fact that some parties (i.e., load-serving entities) may not realize those benefits by nature of their contracts is precisely the point of Paragraph 45;[466] Paragraph 45 imposes no benefits test.

377. Further, we are not persuaded that the Initial Decision improperly shifts the burden of proof to CCG. In stating that it would be inefficient and unfair to require a load-serving entity to file a shift-to-shipper claim against an upstream supplier, the Initial Decision refers to so-called "ripple" claims (further discussed below), which would allow a shipper on the receiving end of a shift-to-shipper claim to shift its SECA liability to an upstream supplier.

[465] The agreement at issue specifically mandates that CCG will be both the supplier and the shipper, in that CCG is obligated to sell and deliver power to Michigan SCPA at a fixed price. White Cross-Answering Test., Ex. MSC-9 at 6:9-12.

[466] The Commission recognized that some parties entered into long-term agreements with wholesale suppliers, which established a fixed, bundled delivered rate that locks in a price that presumes that a regional through-and-out rate is being assessed. As a result, these parties have no choice but to continue to purchase the power from that supplier and, thus, cannot enjoy the benefit of choosing a new supplier that may be more economical due to the elimination of regional through-and-out rates.

378. We will reverse the Initial Decision's finding that Michigan SCPA's shift-to-shipper claim against CCG should be reduced by 21.8 percent. It is true that SECA amounts should be calculated based on test-period data with adjustments for known and measurable differences to most closely reflect future trading patterns. However, the Initial Decision assumes that, because Michigan SCPA simultaneously resold energy in 2005 while it purchased energy from CCG, it did not need the energy purchased from CCG to serve its load. That finding fails to acknowledge the factual record established in this proceeding, which demonstrates that Michigan SCPA's load exceeded its purchases from CCG during the transition period and that Michigan SCPA increased the output of its own plants in 2005, compared to their output in 2002, by more than the 57,354 MWh of power sold to third parties in 2005.

379. We reject Constellation's assertion that a greater reduction is required. Constellation's position is largely based on the unpersuasive argument that, in 2005, Michigan SCPA's and CCG's purchases from other third party suppliers in PJM declined, and they purchased power instead from the Midwest ISO day-ahead and real-time energy markets. Michigan SCPA has a long-term, fixed price, fixed quantity contract with CCG, which is unaffected by any energy market changes, and indeed, the record reveals no substantial difference in the amount of power purchased from CCG that qualifies as a known and measurable change to test-period data.

380. We will require Midwest ISO TOs to submit revised subzonal SECA charges for Michigan SCPA and CCG to reflect the adjustment adopted here in the compliance filings ordered below.

2. Six Michigan Cities' Claim Against CCG

a. Initial Decision

381. The Initial Decision finds that Six Michigan Cities may shift their SECA obligation to CCG.[467] The Initial Decision notes the undisputed fact that CCG was responsible for ensuring that power arrived at or within the METC zone of Midwest ISO and was then scheduled on to Six Michigan Cities.[468] The Presiding Judge further reasons that CCG is both the shipper and the supplier because CCG is the only contractual counterparty to Six Michigan Cities in the bilateral agreement at issue.[469] The Initial Decision dismisses as irrelevant CCG's contention that it did not benefit due

[467] Initial Decision, 116 FERC ¶ 63,030 at P 450.

[468] *Id.* P 445.

[469] *Id.*

to the elimination of regional through-and-out rates, stating that Paragraph 45 of the November 2003 Rehearing Order requires a load-serving entity to demonstrate only that the supplier is the shipper, nothing more (i.e., there is no benefits test).[470] With regard to the exact amount to be shifted, the Initial Decision finds that Six Michigan Cities failed to support the claimed amount of $546,000 and directed that the amount be established in accordance with the Initial Decision.[471]

b. Brief on Exceptions

382. Constellation takes exception to the finding that Six Michigan Cities' SECA liability may be shifted to CCG. Constellation argues that Six Michigan Cities, and all of the Michigan load-serving entities, had access to and the means to interpret North American Electric Reliability Corporation tag data that would have identified the party in the chain of supply that benefited due to the elimination of regional through-and-out rates (which, according to Constellation, was not CCG). Constellation asserts that the Initial Decision fails to require the Michigan load-serving entities to make such a showing, relieving them of their burden of proof.

c. Brief Opposing Exceptions

383. Six Michigan Cities state that each of its members is a load-serving entity with a requirements contract with CCG; those contracts went into effect in January 2001 and are still in effect; and "[b]ecause [CCG] did not present any evidence as to the meaning of those contracts," the "undisputed record evidence" is that CCG is obligated to supply and ensure delivery of power to each of the Six Michigan Cities and pay all costs associated with transmission to the load-serving entities' zone.[472] Accordingly, Six Michigan Cities state that the Initial Decision properly finds in their favor.

384. Six Michigan Cities further assert that: (1) Constellation speaks of a benefits test, where none exists in Paragraph 45; (2) in any case, CCG benefited due to the elimination of regional through-and-out rates; and (3) Constellation has misapplied the principle of cost causation in this proceeding when, in fact, the principle was rightly followed. Six Michigan Cities also state that, contrary to Constellation's position, the Initial Decision does recognize that "supplier" and "shipper" are distinct roles and correctly finds that CCG fulfilled both.

---

[470] *Id.* P 447.

[471] *Id.* P 449.

[472] Six Michigan Cities Brief Opposing Exceptions to the Initial Decision at 2-3, 11-15.

d. **Commission Determination**

385. We will affirm the Initial Decision's finding that CCG is the supplier and the shipper under the requirements contracts with Six Michigan Cities.[473] Contrary to Constellation's argument, the Presiding Judge does not conflate the terms "supplier" and "shipper" as used in Paragraph 45. The Initial Decision recognizes that the roles are distinct and merely finds that CCG fulfilled both. We are not persuaded by Constellation's argument that the Initial Decision relieves Six Michigan Cities of a burden to show that CCG benefited due to the elimination of regional through-and-out rates; as discussed above, Paragraph 45 imposes no such burden. We will require Midwest ISO TOs to submit revised subzonal SECA charges for Six Michigan Cities and CCG to reflect the adjustment adopted here in the compliance filings ordered below.

3. **CCG's Claim Against AEM**

a. **Initial Decision**

386. The Initial Decision finds that CCG may shift, via a "ripple" claim, $809,635 of SECA charges to AEM, subject to any change to the amount based on relevant findings in the Initial Decision.[474] As described in the Initial Decision, ripple claims would allow a shipper on the receiving end of a shift-to-shipper claim to shift its SECA liability to an upstream supplier that benefited due to the elimination of regional through-and-out rates.[475] The Initial Decision finds that, while Commission orders do not explicitly reference the concept of ripple claims, such claims have been deemed fair throughout the course of the hearing.[476] The Initial Decision states that CCG made a sufficient showing to support its ripple claim against AEM using North American Electric Reliability Corporation tag data, revealing that AEM was the transmission customer that sourced power across the Midwest ISO-PJM sink for ultimate delivery to the Michigan load-serving entities. The Initial Decision finds that, since AEM was the shipper in the chain of supply to the Michigan load-serving entities, which benefited due to the elimination of regional through-and-out rates, a "general sense of fairness requires that the SECA charge ultimately rest with [AEM]."[477]

---

[473] Initial Decision, 116 FERC ¶ 63,030 at P 440-45.

[474] *Id.* P 466.

[475] *Id.* P 460.

[476] *Id.*

[477] *Id.*

b. **Brief on Exceptions**

387. AEP contends that nowhere in prior Commission orders is there any mention of shippers on the receiving end of shift-to-shipper claims being permitted to shift their obligations onto upstream suppliers. Therefore, AEP contends, the Initial Decision's decision to allow ripple claims should be rejected as beyond the scope of what the Commission set for hearing in Paragraph 45 of the November 2003 Rehearing Order. AEP argues that any party aggrieved by the November 2003 Rehearing Order because it did not specifically address ripple claims should have sought rehearing of that order rather than trying to insert such claims into the compliance phase of this proceeding.

388. AEP further states that the Initial Decision's rationale for permitting and granting CCG's ripple claim is arbitrary, capricious, and internally inconsistent. AEP contends that, in evaluating the Michigan load-serving entities' shift-to-shipper claim against CCG, the Initial Decision follows the plain language of Paragraph 45, finding that Paragraph 45 did not require load-serving entities to show that the supplier benefited due to the elimination of regional through-and-out rates. AEP further states that, in contrast, the Initial Decision relies upon a benefits test in evaluating CCG's ripple claim against AEM, finding that AEM benefited due to the elimination of regional through-and-out rates and that "a general sense of fairness" requires that the SECA charge ultimately rest with AEM.[478]

389. In any case, AEP states that the argument that AEM, and not CCG, benefited due to the elimination of regional through-and-out rates is speculative, and findings of fact on this point should be reversed. Indeed, AEP asserts that, given the complexity of tracking the benefits of the elimination of regional through-and-out rates up and down the supply chain, the Commission limited Paragraph 45 to provide direct relief for load-serving entities, while remaining "silent about the Byzantine flow of upstream benefits."[479]

---

[478] AEP Brief on Exceptions to the Initial Decision at 22, (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 460). AEP notes that the Initial Decision further states that ripple claims are "clearly consistent with the Commission's underlying intent when drafting Paragraph 45: that the beneficiary of [the] elimination of [regional through-and-out rates] is the appropriate party to pay the transitional SECA charge." *Id.* (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 460).

[479] *Id.* at 24.

390. AEP further argues that, even if various administrative law judges have "deemed [ripple claims to be] fair throughout the course of the hearing,"[480] such determinations do not bind the Commission.

c. **Brief Opposing Exceptions**

391. Constellation states that CCG did not assert a claim against AEM under Paragraph 45 but rather raised its ripple claim as a defense against the shift-to-shipper claims brought by the Michigan load-serving entities. Therefore, Constellation characterizes as misplaced AEP's argument that ripple claims are beyond the scope of both Paragraph 45 and what the Commission set for hearing in the November 2003 Rehearing Order.

392. Constellation agrees with AEP that the Initial Decision is internally inconsistent and that the Initial Decision uses different lines of reasoning in evaluating shift-to-shipper and ripple claims, respectively. According to Constellation, the Initial Decision relies upon an incorrect, unduly restrictive interpretation of Paragraph 45 in evaluating shift-to-shipper claims but the correct, broader interpretation of Paragraph 45 in evaluating ripple claims. Constellation asserts that there is nothing vague about the notion of a "general sense of fairness" as used by the Initial Decision in discussing CCG's claim against AEM. Rather, Constellation contends that the Presiding Judge merely seeks to allocate SECA charges to the beneficiaries of the elimination of regional through-and-out rates, as required by the principle of cost causation and Commission orders.

d. **Commission Determination**

393. We will reverse the Initial Decision's finding that CCG's shift-to-shipper liability may, in turn, be shifted to AEM. Paragraph 45 speaks of load-serving entities making such shift-to-shipper claims, and CCG is not a load-serving entity. Hence, such claims are not available to CCG either as a defense or to shift liability to AEM. In short, in Paragraph 45 the Commission did not provide for ripple claims but rather contemplated only claims by load-serving entities. Having found no express allowance, the Initial Decision attempts to support the notion of ripple claims using a benefits test, an idea that also has no basis in Paragraph 45. In fact, the Initial Decision correctly recognizes that a load-serving entity is not required to satisfy a benefits test in bringing a shift-to-shipper claim, yet it relies upon a benefits test in allowing ripple claims. We see no reason for making such a distinction.

[480] *Id.* at 25 (*citing* Initial Decision, 116 FERC ¶ 63,030 at P 460).

4. Quest's Claim Against MAEM

a. Initial Decision

394. The Initial Decision finds that Quest may shift a portion of its SECA liability to MAEM.[481] Despite finding no formal documentation of a direct contractual load-serving entity-supplier relationship between Quest and MAEM, the Initial Decision accepts Quest's and WPS Energy's argument that a *de facto* contract existed between Quest and MAEM due to: (1) a power contract establishing a relationship between WPS Energy and MAEM; and (2) a credit contract establishing a relationship between WPS Energy and Quest.[482] Quest is a subsidiary of WPS Energy, and the credit arrangement between Quest and WPS Energy enabled WPS Energy to make long-term purchases of power (from MAEM) for Quest.[483] The Initial Decision states that the credit arrangement did not convert WPS Energy into a supplier or shipper for the purposes of Paragraph 45. Rather, the Initial Decision finds that WPS Energy played only a nominal role in what was ultimately a transaction confined to two parties, Quest and MAEM.[484] Having found that Quest may shift a portion of its SECA liability to MAEM, the Initial Decision declines to address the alternative argument that WPS Energy may assert a ripple claim against MAEM in order to pass through Quest's SECA liability.

b. Brief on Exceptions

395. Mirant states that the Initial Decision uses inconsistent and erroneous standards in holding MAEM liable for Quest's SECA obligation. With respect to the agreements between CCG and two load-serving entities, Mirant asserts that the Initial Decision correctly finds CCG liable for a shift-to-shipper claim because there was a bilateral agreement between CCG and the two load-serving entities. Mirant further asserts that the Initial Decision correctly finds that any upstream entities that may have provided power to CCG cannot be deemed to be the suppliers of the load-serving entities; rather, they are suppliers to CCG. On the other hand, according to Mirant, the Initial Decision finds MAEM liable to Quest, even though no bilateral agreement exists between them. Mirant

---

[481] Initial Decision, 116 FERC ¶ 63,030 at P 522.

[482] *Id.* P 512.

[483] As the Initial Decision, 116 FERC ¶ 63,030 at P 514, notes, Quest is a wholly-owned subsidiary of WPS Energy.

[484] *Id.* P 519. Accordingly, the Initial Decision finds that the ripple claim brought by WPS Energy against MAEM is essentially an argument in the alternative and need not be addressed.

analogizes WPS Energy to CCG, stating that WPS Energy is Quest's supplier and MAEM is merely an upstream entity that provided power to WPS Energy. Mirant disputes that a *de facto* contract existed between MAEM and Quest. Mirant asserts that such a determination requires a finding that the parties actually entered into some type of agreement (albeit a flawed one) to pass power from MAEM to Quest.[485]

396. Mirant further argues that Quest is barred from seeking a shift-to-shipper claim here because Quest previously stated, in the context of MAEM's bankruptcy proceeding, that it had no right to payment of SECA charges from MAEM.

397. If the Commission finds that the Initial Decision correctly holds in favor of Quest, then Mirant disputes the Initial Decision's determination of the SECA liability MAEM should have to pay. Moreover, Mirant states that Quest should be prevented from double recovery of its SECA liability, once through MAEM and again through its customers. Mirant takes exception to the Initial Decision's finding that MAEM's ability to pass through 100 percent of its SECA liability to its customers is irrelevant to this case.

c. Brief Opposing Exceptions

398. Quest, Strategic, and WPS Energy argue that the Initial Decision correctly finds in their favor. They contend that, per the credit arrangement between Quest and WPS Energy, Quest would negotiate a power supply arrangement with a supplier, in this case MAEM, to serve its retail load. After the power product specifications were worked out, a contract was executed between MAEM and WPS Energy, and a matching contract was executed between WPS Energy and Quest. This matching contract had the same product definitions, delivery specifications, and start and end date, plus a premium added for the credit risk. Quest, Strategic, and WPS Energy state that there were four power contracts with MAEM for delivered power to Quest that continued into the transition period, and as such, fall within the parameters of Paragraph 45. Quest, Strategic, and WPS Energy contend that, pursuant to the above-described arrangements, MAEM was responsible for delivering power to the specified delivery point (i.e., Michigan Electric Coordinated System (MECS)), and then Quest used its network service transmission to deliver this power to its retail customers in MECS. Quest, Strategic, and WPS Energy argue that MAEM was the shipper because MAEM paid for the transmission to bring the power from the generation source to the specified delivery point.[486] They further state that

[485] Mirant cites Black's Law Dictionary as defining a *de facto* contract as "[o]ne which has purported to pass the property from the owner to another but is defective in some element." Mirant Brief on Exceptions to the Initial Decision at 15, n.60.

[486] In addition, they state that MAEM was the shipper under Commission precedent, including the standards of conduct rules, which consider the "shipper" to be the transmission customer.

MAEM paid the regional through-and-out rate (until its elimination) for power that crossed the Midwest ISO-PJM seam.

399. Quest, Strategic, and WPS Energy further argue that MAEM's and Quest's operations worked together to schedule and deliver power, reconcile previous deliveries, and settle damages if the amounts delivered were more or less than specified in the contracts. They state that WPS Energy was not Quest's agent in these activities and, in fact, was involved only rarely to provide back-up operations.

d. Commission Determination

400. We will reverse the Initial Decision's finding that a contract existed between Quest and MAEM. It is undisputed that there was no bilateral contract between Quest and MAEM, and in the absence of such an agreement, MAEM cannot be liable for a shift-to-shipper claim. We are also not persuaded that a binding contract existed merely because a contract existed between Quest and WPS Energy. We find no case, and the Initial Decision cites none, permitting our reliance on a so-called contract.[487] While it is settled law that a binding contract may be oral or implied, rather than expressed in writing,[488] the fundamental elements of such a contract (such as offer, acceptance, and consideration) are not evidenced here.

5. CCG's Claim Against CMS Energy and Bay City's Claim Against CMS Energy

401. The Initial Decision finds that neither CCG nor Bay City may shift SECA liability to CMS Energy.[489]

402. No party filed a brief concerning this issue. We will summarily affirm the Initial Decision on this point.

---

[487] Nor does the Initial Decision define a *de facto* contract.

[488] Restatement (Second) of Contracts, § 4 (1981).

[489] Initial Decision, 116 FERC ¶ 63,030 at P 455.

N. Green Mountain's Status Vis-à-vis SECA Charges

1. Initial Decision

403. The Initial Decision states that Schedule 22 of the Midwest ISO tariff[490] directs Midwest ISO to bill customers within its pricing zones and designated subzones for SECA charges. The Initial Decision notes that the definition of "customers" in the Midwest ISO tariff is broad and encompasses not only transmission customers but "other entities in a zone…which will bear responsibility for some SECA charges."[491] As discussed below, the Initial Decision finds that Green Mountain[492] is a customer under Schedule 22 and is responsible for SECA charges under Schedule 22, even though it did not directly contract with Midwest ISO.

404. The Initial Decision explains that on March 13, 2001, Green Mountain entered into a firm all-requirements retail electric supply agreement with members of the Northeast Ohio Public Energy Council (NOPEC), and as a result, Green Mountain entered into contracts to obtain power for its Ohio load.[493] The Initial Decision states

[490] Schedule 22 states that: "[c]ustomers as used herein means [t]ransmission [c]ustomers as well as other entities in a zone that may not be [t]ransmission [c]ustomers but which will bear responsibility for some SECA charges. To the extent that the other entities have not executed service agreements, [Midwest ISO] shall file unexecuted service agreements whether the entities request their submission or not." Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, First Revised Sheet No. 1041.

[491] Initial Decision, 116 FERC ¶ 63,030 at P 563 (*citing* Schedule 22, Ex. No. MTO-189 at 1, Midwest ISO Tariff, Third Revised Vol. No. 1, Second Revised Sheet No. 1040, First Revised Sheet No. 1041).

[492] The Initial Decision states that Green Mountain is a privately-held company owned partly by BP International Limited (BP International), which is a wholly-owned subsidiary of BP PLC (the parent company of BP Energy). *Id.* P 561.

[493] Under the Northeast Ohio Public Energy Council Agreement (NOPEC Agreement), entered into on March 31, 2001, Green Mountain agreed to serve retail customers in Northeast Ohio. As a result, Green Mountain entered into contracts to obtain power for its Ohio load. On May 11, 2001, BP Energy, Green Mountain, and CMS Marketing Services and Trading Co. (CMS Marketing) entered into a Power Purchase and Retail Load Serving Agreement under which CMS Marketing became the seller of power to BP Energy for the benefit of Green Mountain. In addition, Green Mountain and BP Energy entered into an Energy Services Agreement under which, among other things, BP Energy began invoicing Green Mountain for the cost of energy for transactions made on behalf of Green Mountain. *Id.*

that, under the Energy Services Agreement between BP Energy and Green Mountain, BP Energy was responsible for providing network transmission service directly to Green Mountain's customers in Ohio, and BP Energy executed contracts on behalf of Green Mountain to arrange for network transmission service. Under these contractual arrangements, BP Energy passed through all energy transmission costs and other direct costs incurred by BP Energy related to the sale of power to Green Mountain. Consequently, the Initial Decision concludes that "[s]ince the procurement of network transmission service was for the benefit of Green Mountain and its financial responsibility, Green Mountain is the entity that paid transmission costs and should pay SECAs."[494] Thus, the Initial Decision finds that Green Mountain is a customer under the Midwest ISO tariff, and Midwest ISO properly filed unexecuted service agreements on Green Mountain's behalf pursuant to Schedule 22.[495]

405. The Initial Decision also finds that Schedule 22 empowers Midwest ISO to collect SECA charges from customers within designated subzones. Specifically, under Schedule 22 the subzones will be customers responsible for sinks for which there is North American Electric Reliability Corporation tag data showing lost revenue responsibility. The Initial Decision finds that Green Mountain has been properly identified as a subzone in the ATSI zone based on North American Electric Reliability Corporation tag data sink codes. Therefore, the Initial Decision concludes that Midwest ISO properly assessed Green Mountain SECA charges as a customer within a designated subzone under Schedule 22.[496]

406. In addition, the Initial Decision finds that the Commission directed that SECA charges be assessed on load-serving entities[497] and that Green Mountain, as a retail generation provider engaged in the retail sale of electric generation, is a load-serving entity. In reaching this conclusion, the Initial Decision states first that the Midwest ISO tariff defines a load-serving entity as "[a]ny entity that has undertaken an obligation to provide electric energy for end-use customers by statute, franchise, regulatory

---

[494] *Id.* P 563.

[495] *Id.* As noted above, Schedule 22 permits Midwest ISO to file unexecuted service agreements even if the entity has not requested such a filing. *Id.* P 524. Midwest ISO filed four unexecuted transmission service agreements and one unexecuted participant agreement. The agreements were filed to invoice Green Mountain for SECA charges. *Id.* P 550, n.119.

[496] *Id.* P 564.

[497] *Id.* P 562 (*citing* November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 45).

requirement or contract for [l]oad located within or attached to the [t]ransmission [s]ystem."[498] Second, the Initial Decision states that the FPA defines a load-serving entity as a distribution utility, and a distribution utility is "an electric utility that has a service obligation to end-users or to a State utility or electric cooperative that, directly or indirectly, through one or more additional State utilities or electric cooperatives, provides electric service to end-users."[499] The Initial Decision explains that, under the NOPEC Agreement, Green Mountain provided all of the electrical energy, capacity, reserves, transmission, and ancillary service for firm power supply to retail customers. Thus, the Initial Decision finds that, since Green Mountain sold power at retail to customers in Northeast Ohio, it qualifies as a load-serving entity; therefore, Green Mountain was properly assessed SECA obligations.[500] The Initial Decision also finds that Green Mountain's assertion that the Commission lacks the necessary jurisdiction to allow Midwest ISO to assess it SECA charges under Schedule 22 is moot, since Green Mountain is a load-serving entity.[501]

407. The Initial Decision adds that Midwest ISO is correct in stating that it is irrelevant whether Green Mountain has completed a Market Participant Application or has been deemed such by Midwest ISO because Schedule 22 does not require an entity to be a market participant in order to be assessed SECA charges.[502] The Initial Decision also states that Green Mountain's argument that Schedule 22 does not apply to it because it is not a transmission customer or market participant is irrelevant because the Initial Decision finds that Green Mountain is a customer under Schedule 22.[503]

408. In addition, the Initial Decision addresses arguments that BP Energy and/or BP International are responsible for paying Green Mountain's SECA obligation. The Initial Decision states that, in light of the Commission's reluctance to pierce the corporate veil, the fact that BP Energy owns a 24.5 percent minority interest in Green Mountain is not

[498] *Id.*; *see also* Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, Third Revised Sheet No. 92.

[499] 16 U.S.C. § 824q(a)(1) (2006).

[500] Initial Decision, 116 FERC ¶ 63,030 at P 562.

[501] *Id.* P 569.

[502] *Id.* P 565.

[503] *Id.* P 569.

persuasive enough to support a finding that BP Energy is the "alter ego" of Green Mountain.[504]

2. Brief on Exceptions

409. Green Mountain argues that the Initial Decision errs in failing to find that the allocation of SECA costs to Green Mountain exceeds the Commission's jurisdiction under the FPA. Green Mountain maintains that the Commission does not have statutory authority to authorize Midwest ISO to bill Green Mountain for SECA charges under Schedule 22 because it was never a transmission customer of Midwest ISO.[505] Green Mountain claims that the Initial Decision's finding is based solely on its conclusion that the language of Schedule 22 permits Midwest ISO to impose that liability on Green Mountain. Green Mountain maintains, however, that the language of a tariff cannot confer upon the Commission jurisdiction that Congress withheld from the Commission.[506]

410. Green Mountain states that, although the Initial Decision correctly finds that the Commission directed that SECA charges be paid by load-serving entities, imposing SECA charges on Green Mountain because it provided retail electric service in Ohio violates fundamental cost-causation principles. Green Mountain asserts that the Initial Decision errs in interpreting the Commission's directive that load-serving entities pay the SECA in a way that exceeds the Commission's jurisdiction (i.e., to allocate SECA liability to Green Mountain, an entity that does not purchase jurisdictional service). Green Mountain adds that, because it never used transmission facilities, the mere fact that it made retail sales cannot justify imposing SECA charges.[507]

411. In addition, Green Mountain argues that it has never been a market participant under the Midwest ISO tariff or in Midwest ISO's Commission-approved markets. Green Mountain also contends that it has not voluntarily entered into any agreements obligating it to pay SECA charges and that Midwest ISO has no contractual privity with Green Mountain.[508] Green Mountain argues that the conclusion that Green Mountain should bear SECA responsibility is based on the finding that BP Energy, Green Mountain's supplier, arranged for network transmission service and Green Mountain

---

[504] *Id.* P 567.

[505] Green Mountain Brief on Exceptions to the Initial Decision at 18-19.

[506] *Id.* at 20-22.

[507] *Id.* at 35-36.

[508] *Id.* at 36-38.

benefited. However, Green Mountain asserts that the Initial Decision's interpretation of the tariff language is incorrect because assessing SECA charges on entities that do not purchase jurisdictional service is beyond the Commission's jurisdiction.[509] Green Mountain claims that it did not purchase network transmission service, but instead purchased a delivered product that included the cost of transmission and other services.[510]

412. Moreover, Green Mountain claims that the Initial Decision erroneously rejects its argument that the unexecuted service agreements could not form a legal basis for charging Green Mountain. Green Mountain claims that it cannot be assigned SECA liability based on unexecuted service agreements for transmission service or market participant status where the record is undisputed that Green Mountain cannot qualify as either a transmission customer or a market participant under the Midwest ISO tariff.[511] In this regard, Green Mountain asserts that the Initial Decision fails to show that Green Mountain meets any of the eligibility requirements for a market participant or a transmission customer and instead relies exclusively on the conclusion that Green Mountain was properly assessed SECA liability under Midwest ISO's interpretation of Schedule 22.[512]

413. Green Mountain also argues that the Initial Decision errs in finding that it was properly designated as a separate subzone based entirely on North American Electric Reliability Corporation tag data. Green Maintain asserts that such tag data is not a reasonable or reliable basis on which to allocate transmission cost responsibility because the tag data merely tracks the contract path of transactions for the sale of power for resale and does not measure cost causation with regard to transmission costs. Green Mountain argues that, since it never purchased through-and-out service from any PJM or Midwest ISO transmission owner and was never a transmission customer of Midwest ISO or a market participant in Midwest ISO's energy markets, the Commission should find that the identification of Green Mountain as a subzone was incorrect.[513]

---

[509] *Id.* at 37.

[510] *Id.* at 40-41.

[511] *Id.* at 28-31.

[512] *Id.* at 31-32.

[513] *Id.* at 48-50.

3. <u>Briefs Opposing Exceptions</u>

414. Midwest ISO argues that the allocation of SECA costs to Green Mountain is within the Commission's jurisdiction under the FPA.[514] Midwest ISO asserts that Schedule 22 obligates Midwest ISO to bill and collect monthly SECA charges from Green Mountain, the entity that bears the responsibility for SECA charges as a load-serving entity; Midwest ISO agrees with the Initial Decision's analysis that Green Mountain qualifies as a load-serving entity. Midwest ISO notes that Green Mountain also entered into an agreement with BP Energy and CMS Marketing, which provides that CMS Marketing sell power to BP Energy for the benefit of Green Mountain and that Green Mountain is responsible for the cost of energy transactions made on behalf of Green Mountain at the energy delivery points for sale to Green Mountain's retail customers. Midwest ISO states that Green Mountain's SECA liability arises from the Commission's order establishing the lost revenue recovery mechanism, under which load-serving entities are to bear SECA responsibility. Therefore, Midwest ISO asks that the Commission affirm the Initial Decision's determination that Midwest ISO may assess SECA charges on Green Mountain as a load-serving entity.[515]

415. In addition, Midwest ISO asserts that the Initial Decision properly concludes that, because the procurement of network transmission service was for the benefit of Green Mountain, Green Mountain is the entity that paid transmission costs and should pay SECA charges.[516] Midwest ISO argues that the Initial Decision properly relies on Green Mountain's contractual arrangements to justify Midwest ISO's assessment of SECA charges to Green Mountain under Schedule 22. Midwest ISO argues that the fact that Green Mountain did not directly contract with Midwest ISO for transmission service to deliver the power to meet its service obligations does not obviate Green Mountain's SECA liability. Midwest ISO adds that Green Mountain ignores the fact that the allocation of SECA charges is not contractually based but that the Commission's SECA rate design provides for a load-based charge.[517] Midwest ISO also claims that Green Mountain's SECA liability is consistent with the Commission's cost-allocation principles. Midwest ISO argues that, in accordance with contractual arrangements with BP Energy, the transmission service it procured was for the benefit of Green Mountain and the cost responsibility is Green Mountain's. Thus, Midwest ISO argues that the

[514] Midwest ISO Brief Opposing Exceptions to the Initial Decision at 12-13.

[515] *Id.* at 13-16.

[516] *Id.* at 18-20.

[517] *Id.* at 20-23.

Commission should uphold the Initial Decision's finding that Green Mountain is the entity responsible for SECA charges.[518]

416. Midwest ISO asks that the Commission affirm the Initial Decision's conclusion that Midwest ISO properly billed SECA charges to Green Mountain as a customer under Schedule 22.[519] Midwest ISO also contends that whether Green Mountain has completed a Market Participant Application for transmission is irrelevant because Schedule 22 provides that, to the extent that entities such as Green Mountain have not executed service agreements, Midwest ISO must file unexecuted service agreements. Thus, Midwest ISO states that it filed the appropriate unexecuted service agreements for invoicing Green Mountain as the party responsible for payment of SECA charges.[520] In addition, Midwest ISO contends that the record supports the Initial Decision's finding that Green Mountain was properly designated a distinct subzone based on North American Electric Reliability Corporation tag data, as well as its finding that Attachment B of Schedule 22 identifies Green Mountain as a subzone and sets forth its SECA obligation. Midwest ISO notes that the tag data identified Green Mountain as a subzone under Schedule 22.[521]

417. AEP, Dayton, and Exelon claim that the Initial Decision's recognition that SECA charges should be allocated to Green Mountain does not exceed the Commission's jurisdiction. They assert that Green Mountain is subject to the Commission's jurisdiction as a competitive retail electric supplier, and as a load-serving entity under the Midwest ISO tariff, and because it was identified via the North American Electric Reliability Corporation tag data as the load-serving entity that imported power over the transmission facilities of AEP, ComEd, and Dayton. AEP, Dayton, and Exelon add that the Commission accepted Schedule 22 of the Midwest ISO tariff, which authorized the terms and conditions under which Midwest ISO collected the PJM transmission owners' lost revenues from Midwest ISO's load-serving entities. They note that Green Mountain required electric transmission service in order to import the power needed to supply its retail obligations in Northeast Ohio and received service from ATSI, the control area operator for FirstEnergy's Ohio service territories under a Network Integration

[518] *Id.* at 23-24.

[519] *Id.* at 20.

[520] *Id.*

[521] *Id.* at 24-27.

Transmission Service Agreement. Thus, they also argue that from October 1, 2003, forward Green Mountain was a *de facto* market participant in Midwest ISO.[522]

418. In addition, AEP, Dayton, and Exelon claim that Green Mountain wrongly argues that the Initial Decision errs in failing to find that the unexecuted service agreements filed by Midwest ISO violate the Midwest ISO tariff.[523] They argue that the Initial Decision correctly finds that Green Mountain is a customer under Schedule 22 of the Midwest ISO tariff and bears responsibility for SECA charges. They add that Green Mountain is also a load-serving entity under the Midwest ISO tariff because it provides electric energy for end-use customers. [524] They also contend that the Initial Decision correctly finds that Green Mountain was a proper subzone, and the use of North American Electric Reliability Corporation tag data is required by the Commission. They note that the Commission accepted Schedule 22, which uses such data as the basis for collecting SECA charges.[525]

419. Midwest ISO TOs[526] argue that the Initial Decision correctly finds that Green Mountain has been properly assessed SECA obligations. In addition, Midwest ISO TOs contend that the Initial Decision properly finds that Green Mountain was a customer under Schedule 22 because of Green Mountain's contractual arrangements with its suppliers and its retail sales activities, and this finding is consistent with the letter and intent of the Commission's orders on the SECA. They add that, through the discussion of Green Mountain's contractual arrangements, the Initial Decision finds that Green Mountain was a load-serving entity.[527]

420. Midwest ISO TOs also contend that Green Mountain's arguments that it should not be assessed a SECA obligation because it was not a transmission customer or market participant must be rejected as a collateral attack on the Commission's orders directing that lost revenue recovery be based on load.[528] Midwest ISO TOs claim that it is

---

[522] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 24-26.

[523] *Id.* at 29.

[524] *Id.* at 30-36.

[525] *Id.* at 37-40.

[526] Hoosier does not join arguments in this brief regarding Green Mountain.

[527] Midwest ISO TOs Brief Opposing Exceptions to the Initial Decision at 35-39.

[528] *Id.* at 38-39.

irrelevant whether Green Mountain has completed a Market Participant Application, and the fact that Schedule 22 includes additional applicability requirements to conform to the Commission's directives does not mean that it is inconsistent with or violates the remainder of the Midwest ISO tariff.[529] Moreover, they note that the Commission explicitly accepted Green Mountain as a subzone by accepting Schedule 22 and Midwest ISO's unexecuted service agreements to collect SECA subzone obligations from Green Mountain.[530]

4. Commission Determination

421. We disagree with the Initial Decision's finding that "[s]ince the procurement of network transmission service was for the benefit of Green Mountain and its financial responsibility, Green Mountain is the entity that paid transmission costs and should pay SECAs."[531] Thus, we will reverse the Initial Decision's conclusions that Green Mountain is a "customer" under the Midwest ISO tariff and that Midwest ISO properly filed unexecuted service agreements on Green Mountain's behalf pursuant to Schedule 22. Consequently, we will also reverse the Initial Decision's conclusion that Midwest ISO properly assessed Green Mountain SECA charges as a customer within a designated subzone under Schedule 22.

422. Instead, we find that BP Energy is responsible for the SECA charges here. BP Energy and Green Mountain negotiated a business arrangement in which the rights and responsibilities of the parties were established by contract. Under its contractual arrangement, if BP Energy failed to pay Midwest ISO for network transmission service, Midwest ISO would have had no recourse against Green Mountain. Likewise, if Green Mountain failed to pay BP Energy under their separate Energy Services Agreement, BP Energy was still obligated to pay Midwest ISO for network transmission service. Accordingly, we will reverse the Initial Decision's finding that Green Mountain should pay SECA charges based on its contractual arrangements.

423. In addition, we find that any claim that we should impose SECA charges on Green Mountain because it provided retail electric service in Ohio is insufficient. We note that the parties here do not dispute the Initial Decision's finding that the Commission directed that load-serving entities be assessed SECA charges. However, we agree with Green Mountain that the mere fact that it made retail sales cannot justify imposing SECA charges. We find that, although Green Mountain qualifies as a load-serving entity

[529] *Id.* at 36, 38.

[530] *Id.* at 6, 39-42.

[531] Initial Decision, 116 FERC ¶ 63,030 at P 563.

because it sold power at retail to customers in Northeast Ohio, as we discussed above, the transmission service in this instance was taken by BP Energy instead of Green Mountain. Thus, we find that Green Mountain is not subject to SECA charges.

424. Furthermore, we find that BP Energy is the entity properly responsible for SECA charges here and not Green Mountain. The SECA as originally proposed and adopted by the Commission is a surcharge to each RTO's license plate zonal rates,[532] and as such it should be assessed to transmission customers taking transmission service under the RTO tariff that pay the license plate zonal rates. Therefore, in this case, since BP Energy is the entity that took transmission service on behalf of Green Mountain through December 2005, BP Energy is responsible for paying SECA charges.

425. We will require the PJM transmission owners to submit revised SECA charges to reflect the adjustments adopted here in the compliance filings ordered below.

O. Contested Settlements Held in Abeyance

1. Exelon Settlement in Docket No. ER05-6-056, *et al.*

426. On March 15, 2006, in Docket No. ER05-6-056, *et al.*, AEP,[533] Exelon,[534] and Wisconsin Public Service Corporation and Upper Peninsula Power Company (jointly, WPSC) (collectively, Exelon Settling Parties) filed a settlement agreement (Exelon Settlement). Section 2.1 of the Exelon Settlement states that the settlement would represent a complete and final settlement of all of WPSC's obligations under the transitional rate mechanism at issue in these proceedings, including lost revenue claims payable by WPSC, amounts owed for existing transactions, potential obligations resulting from any attempt to shift SECA responsibility to WPSC, and any shift-to-shipper claims of WPSC against AEP or any of its subsidiaries. Section 2.2 states that the settlement would not affect lost revenue claims by AEP or Exelon against other parties or potential defenses of other parties against AEP or Exelon to claimed lost revenue responsibility.

---

[532] July 2003 Order, 104 FERC ¶ 61,105 at P 44; November 2003 Rehearing Order, 105 FERC ¶ 61,212 at P 17.

[533] AEP acted on behalf of certain of its operating companies, including: Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, and Wheeling Power.

[534] Exelon acted on behalf of its operating subsidiaries, including: ComEd, PECO, and ExGen.

427. Specifically, under section 3.1, Exelon agrees to pay WPSC $883,158, and AEP agrees to pay WPSC $46,871, within 30 days of the Commission's acceptance of the settlement. Under section 3.2, WPSC agrees that it has paid, and would continue to pay, all SECA charges invoiced by Midwest ISO through March 31, 2006, and no refunds or surcharges would be applied to WPSC's SECA obligations. Under section 3.4, following payment of the SECA charge for the month ending March 31, 2006, WPSC would be subject to no further SECA charges and would not be assessed any surcharges or refunds for SECA amounts previously paid.

428. Under section 3.5, notwithstanding the current revenue distribution provisions of Attachment R of the PJM tariff, all existing transaction revenues that are collected from WPSC and credited against WPSC's SECA obligation and all SECA revenues collected from WPSC by Midwest ISO and remitted to PJM would be distributed according to Appendix A to the settlement. Under section 3.6, to the extent that any portion of the lost revenue claimed by any PJM transmission owner is allocated differently throughout the combined region as a result of any other settlement or Commission decision in these proceedings and to the extent that such settlement or Commission decision assigns charges or lost revenues to WPSC other than those provided under the settlement, WPSC would be exempt from, and would not pay, such charges whether the charges are applicable under the Midwest ISO or PJM tariffs. AEP and Exelon would also waive and instruct Midwest ISO to credit and not to collect from any load within Midwest ISO any lost revenues that AEP and Exelon could have claimed in excess of the lost revenue claims resolved under the settlement and charged to WPSC under the rate design adopted by the Commission in these proceedings. Under section 3.7, AEP and Exelon agree not to seek to impose a SECA or similar charge on WPSC, prior to February 1, 2008.

a. Comments

429. On March 23, 2006, AMP-Ohio filed comments objecting to the settlement because it could result in the imposition of costs on non-settling parties to the settlement. AMP-Ohio asks that the Commission accept the settlement only if it is modified to explicitly protect non-settling parties from additional charges resulting from the settlement. AMP-Ohio asserts that it should not be required to make increased payments as a result of the provisions in this settlement that would eliminate WPSC's responsibility for surcharges resulting from a Commission decision in these proceedings. AMP-Ohio states that, if the terms of the settlement can be clarified by Exelon Settling Parties in the form of comments or reply comments in response to AMP-Ohio's concerns, then modification of the settlement may not be necessary.

430. On March 24, 2006, FirstEnergy filed comments objecting to the settlement. FirstEnergy claims that the settlement would result in the under collection of lost through-and-out revenues and could result in the imposition of additional SECA charges on non-settling parties. FirstEnergy asks that the Commission accept the settlement only if it is modified to explicitly protect non-settling load-serving entities from additional

SECA charges resulting from the settlement. Specifically, FirstEnergy asks that Attachment R of the PJM tariff be revised to reflect the reduction in 2002 and 2003 lost revenues by AEP, Dayton, and Exelon that results from the distribution of SECA revenues collected from WPSC under Appendix A. FirstEnergy asserts that otherwise non-settling PJM transmission owners would under collect their share of the 2002 and 2003 lost revenues collected in SECA charges and existing transaction charges, and AEP, Dayton, and Exelon would collect more in SECA revenues than they would otherwise.

431. In addition, FirstEnergy argues that the settlement does not provide that non-settling PJM transmission owners would be made whole in the event that any portion of the lost revenue of such transmission owners is allocated differently throughout the combined region as a result of any settlement or Commission decision in these proceedings. It states that, without such a provision, the settlement could result in a non-settling PJM transmission owner being unable to collect lost revenue to which it would otherwise be entitled from WPSC. Thus, FirstEnergy asserts that the settlement should provide that WPSC or AEP and Exelon or a combination thereof would agree to pay to any PJM transmission owner any such lost revenue. FirstEnergy also contends that, under the settlement, WPSC would not be responsible for any surcharge or any additional lost revenues or SECA obligations that could be owed to any PJM transmission owner as a result of any settlement or Commission decision in the SECA proceedings. Therefore, FirstEnergy claims that the settlement does not address how any additional surcharge, lost revenues or SECA obligations owed by WPSC would be paid to non-settling PJM transmission owners, and this creates the risk that other load-serving entities could be made responsible for such charges.

432. On March 24, 2006, Trial Staff filed comments supporting the settlement. Trial Staff notes that AMP-Ohio filed initial comments on the settlement asking for further clarification that the settlement would not result in other parties having to bear additional SECA costs. Trial Staff asks that Exelon Settling Parties confirm this understanding.

433. On March 29, 2006, Exelon Settling Parties filed reply comments. They assert that the settlement is a bilateral settlement that would resolve all issues in the proceedings with respect to Exelon, AEP, and WPSC, and it would not adversely affect non-settling parties. They explain that non-settling load-serving entities would not be adversely affected by the settlement in that revenues assessed through the SECA charges of other load-serving entities and existing transactions charges payable by other load-serving entities taking transmission service from PJM are outside of the scope of the settlement. They add that, because the settlement would resolve WPSC's obligation to pay the SECA and existing transaction charges *among the Settling Parties*, non-settling load-serving entities would not be adversely affected by the resolution of WPSC's obligations, and none of WPSC's obligations under the compliance filings could be shifted to other parties. Furthermore, they state that AEP and Exelon have agreed to waive any claims that they might otherwise have to collect lost revenues that would be allocated to WPSC

under an allocation scheme different from the SECA allocation adopted by the Commission, and this waiver provides an added measure of protection to other load-serving entities in the unlikely event that the SECA mechanism is replaced with a different allocation scheme. In addition, they reject FirstEnergy's suggestion that they have a responsibility to guarantee that non-settling PJM transmission owners would be made whole if the Commission were to adopt a different allocation scheme. They add that the non-settling PJM transmission owners would not be adversely affected by the settlement because they do not have lost revenue claims that have been allocated to WPSC under the compliance filings or supporting testimony.

434. They also claim that neither FirstEnergy nor AMP-Ohio raise any genuine issue of material fact. In this regard, they contend that neither FirstEnergy nor AMP-Ohio point to anything in the compliance filings or to any testimony to support their request that the settlement be modified to hold non-settling parties harmless from the impact of a hypothetical Commission decision that would allocate lost revenues in a manner different from the compliance filings. Moreover, AEP and Exelon assert that they intend to have the PJM transmission owners file a revised Attachment R of the PJM tariff to remove AEP, ComEd, and Dayton's lost revenue claims that have been allocated to WPSC from the determination of revenue distribution percentages.

435. On March 26, 2008, Exelon filed for expedited approval of the pending settlements. Exelon argues that objections to the settlement are now moot because the PJM transmission owners, including FirstEnergy, adopted a resolution and filed new tariff sheets to implement settlements that avoid the issue regarding non-settling parties.[535] Exelon adds that the Commission accepted that filing.[536] Thus, Exelon claims that FirstEnergy's concern that non-settling PJM transmission owners may not be protected from under-collection of lost regional through-and-out rates has been resolved and is moot. In addition, Exelon states that the Commission approved settlements resolving SECA issues between AMP-Ohio and ComEd on October 27, 2006,[537] AMP-Ohio and AEP on July 3, 2007,[538] and AMP-Ohio and other PJM transmission owners on

[535] Exelon states it was agreed that: (1) WPSC owes FirstEnergy no SECA payments; and (2) to the extent that a final order by the Commission eventually increases the SECA obligations of other load-serving entities, any adverse impact of that decision on FirstEnergy as a load-serving entity would be unrelated to and unaffected by the settlement with WPSC.

[536] *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER05-6-057, *et al.* (July 19, 2006) (unpublished letter order).

[537] *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 FERC ¶ 61,121 (2006).

[538] July 2003 Order, 120 FERC ¶ 61,009.

October 25, 2007.[539] Therefore, Exelon argues that AMP-Ohio's concerns regarding the Exelon Settlement are also now moot. In its recent answer, WPSC asserts that Exelon correctly states that all of the issues raised by AMP-Ohio and FirstEnergy have been resolved or are now moot, so that the Commission can accept the Exelon Settlement.

436. On April 1, 2008, WPSC filed an answer in support of Exelon's motion for expedited approval of its pending settlement. WPSC asserts that the settlement represents a resolution of all issues involving the SECA responsibility of WPSC and that, after the Commission approves the settlement, WPSC will withdraw from these proceedings. WPSC argues that Exelon correctly states that all of the issues that FirstEnergy and AMP-Ohio raise have been resolved or are now moot, so that the Commission can accept the settlement.

b. Certification

437. On April 26, 2006, the Presiding Judge certified the Exelon Settlement as a contested partial settlement.[540] With regard to AMP-Ohio's and FirstEnergy's allegations that the settlement could result in surcharges or other obligations being paid by non-settling parties, the Presiding Judge notes that Exelon Settling Parties point out that non-settling parties would not be adversely affected by the settlement because WPSC's entire SECA obligation under the compliance filings is payable to ComEd, AEP, and Dayton. Consequently, the Presiding Judge states that non-settling PJM transmission owners do not have lost revenue claims assessed against WPSC under the compliance filings, as evidenced by the compliance filings and supporting testimony in these proceedings.

438. The Presiding Judge adds that Exelon Settling Parties are correct that, since no other PJM transmission owner is owed lost revenues under the SECA assessed against WPSC under the compliance filings and all of WPSC's through-and-out payments under existing transactions have been credited against its SECA obligation, other PJM transmission owners would not be adversely affected by the settlement. Furthermore, the Presiding Judge states that non-settling load-serving entities would not be adversely affected by the settlement because none of WPSC's obligations under the compliance filings can be shifted to other parties. In addition, the Presiding Judge notes that AEP and Exelon waived any claims that they may have to collect lost revenues that would be allocated to WPSC under an allocation scheme different than the SECA allocation adopted by the Commission. The Presiding Judge also explains that Exelon Settling Parties are correct that they are not responsible for protecting non-settling parties from

[539] *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,086 (2007).

[540] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 63,018 (2006).

impacts that do not result from the settlement (i.e., the possibility of revenue collection allocated to WPSC under a different allocation scheme or some hypothetical change in administrative decisions), and accordingly, there are no genuine issues of material fact concerning the settlement.

439. In addition, the Presiding Judge notes that Exelon Settling Parties have resolved the issue raised by FirstEnergy that Attachment R to the PJM tariff be revised to reflect the changes in revenue allocations made under Appendix A to the settlement. In this regard, the Presiding Judge explains that, in their reply comments, Exelon Settling Parties state that the PJM transmission owners expect to file appropriate revisions to the PJM tariff in April 2006. Finally, the Presiding Judge points out that the just and reasonable standard of review applies to changes to the settlement.

c. <u>Commission Determination</u>

440. We note that Exelon Settling Parties state that, because the settlement would resolve only WPSC's obligations among Exelon Settling Parties, non-settling load-serving entities would not be adversely affected by the resolution of WPSC's obligations. Moreover, in their recent filings Exelon and WPSC add that all of the issues raised by AMP-Ohio and FirstEnergy have been resolved or are now moot. In this regard, we note that no party to this proceeding has protested Exelon's and WPSC's recent filings or has otherwise disputed their claims. Therefore, we find that the Exelon Settlement is uncontested and is, as well, fair and reasonable and in the public interest, and we will approve the Exelon Settlement.[541] Our approval of the Exelon Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

441. This order will terminate Docket Nos. ER05-6-056, EL04-135-058, EL02-111-076, and EL03-212-072.

2. <u>Dowagiac Settlement in Docket No. ER05-6-048, *et al.*</u>

442. On March 17, 2006, Exelon[542] and the City of Dowagiac, Michigan (Dowagiac) (collectively, Dowagiac Settling Parties) filed a Stipulation and Agreement (Dowagiac

---

[541] We also note that, in *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,332, at P 15 (2008) (December 2008 Order); July 2003 Order, 120 FERC ¶ 61,009 at nn.7, 10, the Commission found that claims by non-settling parties that they would be adversely affected by settlement provisions were unsubstantiated and speculative and did not raise issues of material fact.

[542] Exelon acted on behalf of its operating subsidiaries, including: ComEd, PECO, and ExGen.

Settlement). The settlement provides that it would satisfy all of Dowagiac's monetary obligations under the transitional rate mechanism at issue in these proceedings, including any and all lost revenue claims payable by Dowagiac, any potential obligations resulting from any attempt to shift SECA responsibility to Dowagiac, and any shift-to-shipper claims of Dowagiac against Exelon or any of its subsidiaries. Dowagiac Settling Parties state that the settlement would not affect the amount of lost revenue any transmission owner may claim against any other party to these proceedings, and the settlement would not affect any potential defense any party to these proceedings may have regarding any issue.

443. Section 3 of the Dowagiac Settlement provides that Exelon agrees to pay Dowagiac $50,000 within 30 days of the Commission's acceptance of the settlement, obligates Dowagiac to pay all SECA charges invoiced by PJM for SECA amounts applicable through the end of the transition period, March 31, 2006, and provides further that no surcharges or refunds would be applied to Dowagiac's SECA obligations. Section 3.3 provides that, following payment of the SECA invoice to Dowagiac for the month ending March 31, 2006, Dowagiac would no longer be subject to SECA charges applicable to it under the PJM tariff and would not be assessed any surcharges or refunds for SECA amounts previously paid.

a. <u>Comments</u>

444. On March 24, 2006, FirstEnergy filed comments objecting to the settlement. FirstEnergy claims that the settlement would result in the under collection of lost through-and-out revenues and could result in the imposition of additional SECA charges on non-settling parties. FirstEnergy claims that the settlement does not provide that non-settling PJM transmission owners would be made whole in the event that a surcharge is assessed to Dowagiac. FirstEnergy argues that, without such a provision, the settlement could result in a non-settling PJM transmission owner being unable to collect lost revenues to which it would otherwise be entitled. FirstEnergy contends that the settlement should provide that Dowagiac or Exelon or a combination of both agree to pay to any PJM transmission owner any such lost revenue.

445. FirstEnergy also asserts that, under the settlement, Dowagiac would not be responsible for any surcharge that may be owed to any transmission owner; the settlement does not address how any additional surcharge otherwise owed Dowagiac would be paid, nor does it provide a waiver from Exelon that it would not try to collect any such surcharge from any other load in the Midwest ISO region. FirstEnergy asks that the Commission accept the settlement only if it is modified so that it would explicitly protect non-settling PJM transmission owners from the under collection of their lost through-and-out revenues and would protect non-settling party load-serving entities from additional SECA charges that could result from the settlement.

446. On March 24, 2006, Trial Staff filed comments supporting the settlement.

447. On March 29, 2006, Dowagiac Settling Parties filed reply comments. They state that the settlement is a bilateral settlement that would resolve all issues in the proceedings *between Exelon and Dowagiac*, and it would not adversely affect non-settling parties. They state that Dowagiac's entire SECA obligation under the compliance filings and the supporting testimony is predicated on claimed lost revenues payable to ComEd alone. They argue that, since Dowagiac is not a transmission customer under an existing transaction, none of the revenues being collected from Dowagiac under the compliance filings are payable to any PJM transmission owner other than ComEd. Thus, they maintain that none of the other PJM transmission owners, including FirstEnergy, would be adversely affected by the settlement.

448. In addition, they maintain that non-settling load-serving entities would not be adversely affected by the settlement. They claim that lost revenues assessed through the SECA charges of other load-serving entities and existing transaction charges payable by other load-serving entities taking transmission service from PJM are outside of the scope of the settlement. They claim that, since the settlement would resolve Dowagiac's obligation to pay SECA charges among Dowagiac Settling Parties, non-settling load-serving entities would not be adversely affected by the resolution of Dowagiac's obligations, and none of Dowagiac's obligations under the compliance filings can be shifted to them.

449. They also reject FirstEnergy's suggestion that they have the responsibility to guarantee that non-settling PJM transmission owners will be made whole if the Commission were to adopt a surcharge for which neither FirstEnergy nor any other participant has provided support. Furthermore, Dowagiac Settling Parties reject FirstEnergy's request that they modify the settlement to protect non-settling load-serving entities from adverse effects resulting from a decision by the Commission to assign lost revenues differently. In this regard, they argue that they are not responsible for protecting non-settling parties from impacts resulting not from the settlement but from a hypothetical Commission decision.

450. On March 26, 2008, Exelon filed for expedited approval of the pending settlements in these dockets. Exelon argues that the objections are moot, since after the filing of comments the PJM transmission owners filed new tariff sheets that avoid the issue raised by FirstEnergy regarding non-settling transmission owners, and the Commission accepted that filing. Thus, Exelon claims that FirstEnergy's concern that non-settling PJM transmission owners may not be protected from the under collection of lost regional through-and-out rates has been resolved and is moot.

b. Certification

451. On April 20, 2006, the Presiding Judge certified the Dowagiac Settlement as a contested partial settlement.[543] The Presiding Judge states that the settlement would satisfy all of Dowagiac's monetary obligations under the transitional rate mechanism at issue in this case, including all of ComEd's lost revenue claims payable by Dowagiac and potential obligations resulting from any attempt to shift SECA responsibilities to Dowagiac, as well as all shift-to-shipper claims of Dowagiac against Exelon or its subsidiaries. The Presiding Judge also states that the settlement would not affect any lost revenue claims by ComEd against other parties or the defenses other parties may have against ComEd's lost revenue claims, and it would remove Dowagiac from active participation in these proceedings. The Presiding Judge adds that the settlement is certified because there are no genuine issues of material fact precluding certification of the settlement, and the record contains sufficient evidence from which the Commission may reach a decision on the merits.

452. In response to FirstEnergy's allegations that the settlement could result in non-settling parties paying surcharges or other obligations, the Presiding Judge notes that Dowagiac Settling Parties point out that non-settling parties would not be adversely affected by the settlement. The Presiding Judge states that Dowagiac Settling Parties are correct that, since no other PJM transmission owner is owed lost revenues under the SECA assessed against Dowagiac under the compliance filing, other PJM transmission owners would not be adversely affected by the settlement. The Presiding Judge also states that Dowagiac Settling Parties are correct that non-settling load-serving entities would not be adversely affected by the settlement because none of Dowagiac's obligations under the compliance filings can be shifted to other parties.

453. The Presiding Judge adds that Dowagiac Settling Parties are correct that they are not responsible for protecting non-settling parties from impacts that do not result from the settlement (i.e., the possibility of revenue collection allocated to Dowagiac under a different allocation scheme or some hypothetical change in administrative decisions). In this regard, the Presiding Judge notes that the mere allegation that non-settling parties could be adversely affected by the settlement does not raise a genuine issue of material fact. Lastly, the Presiding Judge finds that the just and reasonable standard of review applies to changes to the settlement.

[543] *Midwest Indep. Transmission Sys. Operator, Inc., et al.*, Docket No. ER05-6-048, *et al.* (Apr. 20, 2006) (unpublished certification of contested partial settlement).

c. **Commission Determination**

454. We note that Dowagiac Settling Parties state that the settlement is a bilateral settlement that would resolve all issues in the proceedings but only between Exelon and Dowagiac and would not adversely affect non-settling parties. Moreover, in its recent filing Exelon adds that all of the issues raised by FirstEnergy have been resolved or are now moot. In this regard, we note that no party to this proceeding has protested Exelon's recent filing or has otherwise disputed its claims. Therefore, we find that the Dowagiac Settlement is uncontested and is, as well, fair and reasonable and in the public interest, and we will approve the Dowagiac Settlement. Our approval of the Dowagiac Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

455. This order will terminate Docket Nos. ER05-6-048, EL04-135-088, EL02-111-105, and EL03-212-101.

3. **Allegheny Power Settlement in Docket No. ER05-6-050, *et al*.**

456. On March 17, 2006, Allegheny Power, on behalf of itself and the other executing parties, Dayton, Dominion, Exelon,[544] PPL, Pepco, Rockland, and UGI (collectively, Allegheny Power Settling Parties), filed a Settlement Agreement (Allegheny Power Settlement). The settlement provides that it would resolve among the respective parties all issues related to the SECA charges on the basis of the imposition of 80 percent of all SECA charges as requested in the various compliance filings. The Allegheny Power Settlement would also resolve additional issues related solely to the allocation of resulting SECA amounts among competing load-serving entities.

457. Specifically, as part of the consideration for settling at the 80-percent level, Allegheny Power Settling Parties agree in section 1.3 of the Allegheny Power Settlement to support an effective date no earlier than February 1, 2008, for any change in the PJM regional rate design that may result from the proceedings in Docket No. EL05-121-000. Section 2.1 would resolve all issues among Allegheny Power Settling Parties by allowing for SECA recovery at the level of 80 percent of the SECA requests contained in the compliance filings. Section 2.2 would resolve a PJM subzone issue, which affects the allocation of SECA responsibility only among those loads within the Classic PJM transmission rate zones and the Allegheny Power zone. Section 2.2.4 states that Allegheny Power Settling Parties would request, in accordance with section 5.1, that the Commission impose the terms of the agreement, including section 2.2, on non-settling load-serving entities, which would be affected by section 2. Section 2.3 provides a mechanism to ensure that Allegheny Power Settling Parties would be kept whole with

[544] Exelon acted on behalf of ComEd and PECO.

respect to any other disputes over subzonal allocations of SECA responsibility. Section 2.3 specifies that any such subzonal allocation issues would not be resolved by the settlement and could be resolved through continuing litigation or separate settlement.

458. Section 3.1 states that, except as provided in section 5.1, the settlement would not resolve issues being litigated in the SECA proceedings involving one or more Allegheny Power Settling Parties, on the one hand, and one or more non-settling parties, on the other hand. Section 4.1 states that the term "affiliate" would mean any two or more entities, one of which controls the other or that are under common control. Section 5.1 states that Allegheny Power Settling Parties agree to file the agreement as a non-contested settlement among Allegheny Power Settling Parties and their affiliates and as a contested offer to resolve the SECA proceedings in Docket No. EL02-111-070, *et al.* Allegheny Power Settling Parties request that the Commission accept the settlement as an agreement among them and impose the agreement on non-settling parties as a contested settlement of all issues in the SECA proceedings to the maximum extent consistent with the Commission's rules respecting treatment of contested settlements, except for issues referred to in sections 2.3 and 2.4, by revising all SECA charges to reflect the same 80-percent SECA charge adjustment described in section 2.1.

459. Section 8.4 also states that the Commission's right to change any charges established under the settlement would be limited to the extent permissible by law in accordance with the *Mobile-Sierra* public interest standard applicable to fixed-rate agreements.

a. <u>Comments</u>

460. Pennsylvania Public Utility Commission (Pennsylvania Commission) asserts that imposing the SECA is contrary to the provisions of the FPA and that discounting the SECA charges by 20 percent under the Allegheny Power Settlement would allow Allegheny Power Settling Parties to collect 80 percent of an unlawful rate. Pennsylvania Commission also contends that the settlement would not resolve load-serving entities' concerns regarding the SECA cost allocation methodology.

461. CMS Energy, Detroit Edison, Wolverine, Duquesne, Trial Staff, WPSC, Midwest ISO TOs,[545] Quest, and AMP-Ohio oppose the settlement because it would impose on non-settling parties all SECA charges to 80 percent of the amounts that are currently on file with the Commission. Multiple TDUs[546] state that they do not take a position on the settlement as among Allegheny Power Settling Parties, but assert that imposing the 80

---

[545] For the purpose of this filing, Midwest ISO TOs did not include ATSI.

[546] For the purpose of this filing, Multiple TDUs also include Dowagiac and Wayne-White Counties Electric Cooperative.

percent result on non-settling parties would violate due process and reasoned decision-making.

462. AEP, Midwest ISO TOs, WPSC, Ormet, Green Mountain, and Constellation argue that the Presiding Judge should not certify the settlement as to them because there are genuine issues of material fact regarding the settlement. Furthermore, they contend that the record does not contain substantial evidence that would permit the Commission to reach a reasoned decision on the merits of the contested issues. AMP-Ohio also argues that Allegheny Power Settling Parties have not provided any support for the SECA charges. Green Mountain maintains that imposing the settlement on it would be unlawful because the imposition of SECA charges constitutes a *per se* violation of the filed rate doctrine and the rule against retroactive ratemaking. Constellation argues that the settlement would not provide an overall just and reasonable result or explain the justness and reasonableness in resolving the Allegheny Power subzonal issue without addressing other subzonal issues and other SECA issues.

463. WPSC and Wisconsin Electric Power Company (Wisconsin Electric) ask that the settlement explicitly state that it would not apply to any party that has already entered into a settlement that resolves all issues in contention as applicable to that party. Multiple TDUs state that it is unclear how section 5.1 would apply to the Dowagiac Settlement.

464. WPSC and Wisconsin Electric also ask that the definition of "affiliate" explicitly exclude Wisconsin Electric and Edison Sault Electric Company because both parties have already entered into a settlement that resolves all of their issues in this case. BG&E argues that the settlement would deprive BG&E of the choice of becoming an Allegheny Power Settling Party based on the partial opposition of other parties because of their affiliate relationship.

465. FirstEnergy states that, contrary to the language of section 5.1, the settlement does not provide for the settlement of the existing transaction dispute. Thus, FirstEnergy asserts that the settlement should be modified to provide that load-serving entities paying regional through-and-out rates for existing transactions would be entitled to a refund at the end of the transition period of any existing transaction charges in excess of their SECA obligations. Madison Gas and Electric Company opposes the Allegheny Power Settlement until it is modified to explicitly require Allegheny Power Settling Parties to refund existing transaction payments that would: (1) exceed a load-serving entity's SECA obligation under the terms of the settlement; and (2) would not be otherwise credited against that load-serving entity's SECA obligation during the transition period.

466. Michigan SCPA and Michigan PPA argue that the settlement should be modified to explain that: (1) participating in the settlement would not extinguish their rights to pursue shift-to-shipper claims; (2) they are not waiving any arguments regarding the legality of the SECA; and (3) if the transmission owners who receive the SECA charges

of Michigan SCPA and Michigan PPA oppose the settlement, then Michigan SCPA and Michigan PPA would not be bound by the terms of the settlement.

467. On April 17, 2006, Allegheny Power Settling Parties filed reply comments in which they clarify that the settlement would not, and is not intended to, have any effect on previously-submitted uncontested settlements; nor is it intended to have any effect on other uncontested settlements that may be submitted prior to the Commission's acceptance of the Allegheny Power Settlement. They also concede that certification as a contested settlement cannot occur in accordance with the Commission's rules until after the issuance of an initial decision that resolves genuine issues of material fact. Thus, they request that the settlement be certified as a non-contested settlement affecting *only* Allegheny Power Settling Parties. Furthermore, they claim that the settlement does not need to be modified because Allegheny Power Settling Parties have met their obligations under section 5.1, while preserving their rights, and the rights of any other party, to file a similar or identical settlement once genuine issues of material fact are resolved.

b. <u>Certification</u>

468. On May 11, 2006, the Presiding Judge certified the Allegheny Power Settlement as a contested partial settlement.[547] The Presiding Judge states that the settlement would resolve the issues between Allegheny Power Settling Parties, including whether Allegheny Power's SECA obligation should be calculated as a subzone rather than a PJM-wide SECA charge, and that the settlement provides that the SECA charges would be reduced by 20 percent of the level requested in the compliance filings. The Presiding Judge adds that Allegheny Power Settling Parties agree to support February 1, 2008, as the effective date for changes in the PJM regional rate design in Docket No. EL05-121-000 and that section 2.2 of the settlement would resolve a subzone issue raised by Allegheny Power. The Presiding Judge notes that the Allegheny Power subzone issue affects the allocation of SECA responsibility among the Classic PJM transmission rate zones and the Allegheny Power zone and that the settlement would set the allocator for the Allegheny Power zone at the halfway point between the load ratio-based allocator in the compliance filings and the import ratio allocator used by Allegheny Power in its testimony and exhibits.

469. The Presiding Judge states that commenters request that the settlement not be certified, to the extent that it would bind non-settling parties, and that Allegheny Power Settling Parties resolved this objection by asking that the settlement be certified only as to them. The Presiding Judge also finds that the modifications that the non-settling parties request in their comments are moot because Allegheny Power Settling Parties agreed not to seek to impose the settlement on non-settling parties. In addition, the Presiding Judge

[547] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 63,031 (2006).

states that, since the settlement would not be imposed on non-settling parties, Midwest ISO TOs would not collect less than the amount that they request in the compliance filings, and because Allegheny Power Settling Parties have agreed not to bind the non-settling parties, the settlement would not force any non-settling party to pay additional costs. The Presiding Judge also states that, since the settlement is limited to Allegheny Power Settling Parties, it would not affect pending settlements of shift-to-shipper claims. Thus, the Presiding Judge finds that the objecting parties fail to raise any genuine issues of material fact sufficient to prevent certification of the settlement or to require modification of the settlement.

470. The Presiding Judge responds to Pennsylvania Commission's allegation that the settlement would fail to protect end users adequately by stating that Pennsylvania Commission fails to show that its objection presents a genuine issue of material fact that should preclude certification of the settlement. The Presiding Judge finds that Pennsylvania Commission's arguments actually concern the Commission's decision to recover lost revenues through SECA charges.

471. Lastly, the Presiding Judge states that the *Mobile-Sierra* public interest standard of review would apply to Commission-initiated changes to the settlement.

c. Commission Determination

472. We agree with the Presiding Judge that Allegheny Power Settling Parties have resolved commenters' objections to the settlement; Allegheny Power Settling Parties' reply comments indicate that the settlement would affect only Allegheny Power Settling Parties and do not seek to impose the settlement on non-settling parties.

473. In addition, we note that Allegheny Power Settling Parties clarify that the settlement would not have any effect on previously-submitted settlements and is not intended to have any effect on other settlements. We also agree with the Presiding Judge that Pennsylvania Commission's allegation that the settlement would fail to protect end users adequately does not present a genuine issue of material fact but, rather, is a challenge to the legality of the SECA, an issue addressed at length elsewhere in this order and others. In this regard, we note that, in the accompanying rehearing order, we address concerns about the legality of the SECA raised by Pennsylvania Commission and others on rehearing of prior Commission orders and uphold the Commission's decision to establish SECA charges.

474. Therefore, we find that the Allegheny Power Settlement is uncontested and is, as well, fair and reasonable and in the public interest, and we will approve the Allegheny Power Settlement. Our approval of the Allegheny Power Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

475. This order will terminate Docket Nos. ER05-6-050, EL04-135-052, EL02-111-070, and EL03-212-066.

4. FirstEnergy Entities Settlement in Docket No. ER05-6-113, *et al.*

476. On October 29, 2009, FirstEnergy Service on behalf of itself and ATSI, CEI, Ohio Edison, Pennsylvania Power, Toledo Edison, JCPL, MetEd, Penelec, and FirstEnergy Solutions (collectively, FirstEnergy Entities) and Exelon on behalf of ComEd, ExGen, Exelon Energy Company, and PECO (collectively, Exelon Entities) filed a Settlement Agreement and Explanatory Statement (FirstEnergy Entities Settlement). The settlement resolves the SECA obligations between FirstEnergy Entities and Exelon Entities (collectively, Settling Parties).

477. Specifically, section 2.2 of the FirstEnergy Entities Settlement provides that the settlement would not affect the amount of lost revenue that any non-settling transmission owner may claim against any other party to these proceedings, nor would it affect any potential defenses that any other party might have to any claimed lost revenue responsibility. Section 3.1 states that, except as provided in section 3.7, Exelon Entities would accept responsibility with respect to a total monetary obligation to FirstEnergy Entities in the amount of $4,540,667, and FirstEnergy Entities would accept responsibility with respect to a total monetary obligation to Exelon Entities in the amount of $1,658,898. Section 3.5 provides that Exelon Entities would no longer be subject to intra-PJM and inter-RTO SECA charges applicable to any lost revenue claim of any FirstEnergy Entity. Similarly, FirstEnergy Entities would no longer be subject to intra-PJM and inter-RTO SECA charges applicable to any lost revenue claim of any Exelon Entity.

478. Section 3.7 of the FirstEnergy Entities Settlement provides that, to the extent that the final resolution of the SECA proceedings results in a shift or assessment to any FirstEnergy Entity of all or a portion of the SECA obligation that was owed to Exelon by Green Mountain or Quest under the compliance filings set for hearing in the SECA proceedings, such FirstEnergy Entity would pay seventy percent of such SECA obligation that is owed to Exelon. Exelon would waive and instruct PJM and Midwest ISO to credit and not to collect from any of the FirstEnergy Entities or load or other load-serving entities within the combined region any portion of the shifted or reassessed SECA obligation that could have been claimed by Exelon in excess of the seventy percent of such SECA obligation.

479. Section 6.4 of the FirstEnergy Entities Settlement provides that the settlement could be amended only by agreement in writing of all parties. The standard of review for any modifications to the settlement requested by a party that are not agreed to by all parties shall be the public interest standard as set forth in *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1 of Snohomish County, Washington*, 128 S. Ct. 2733 (2008). The standard of review for any modifications to the settlement requested by a non-party

to the settlement and the Commission would be the most stringent standard permissible under applicable law.

a. **Comments**

480. On November 18, 2009, Quest and Integrys Energy Services, Inc. (Integrys Energy) filed comments. Quest and Integrys Energy state that they are concerned that section 3.7 of the FirstEnergy Entities Settlement was not in any of the settlements filed to date in these proceedings. Thus, Quest and Integrys Energy ask that the Commission confirm that FirstEnergy Service and Exelon cannot preclude the recovery of SECA amounts ultimately found to be due to Quest and Integrys Energy based on a subsequent Commission or court order. They add that, although the settlement contains similar provisions (e.g., sections 2.2 and 3.5) to settlements that Quest and Integrys Energy have protested in the past, the Commission already assured Quest and Integrys Energy that those provisions cannot bar recoveries by Quest and Integrys Energy of overpayments, and thus, they will not protest them.

481. On November 24, 2009, Settling Parties filed reply comments. They state that the Commission approved two settlements in these proceedings with nearly identical language to section 3.7. They also assert that Quest and Integrys Energy do not protest sections 2.2 and 3.5 here because the Commission has already found their arguments unfounded and addressed by the terms of the settlements and has assured that those provisions cannot bar recoveries by Quest and Integrys Energy of overpayments. Thus, the Settling Parties maintain that the confirmation that Quest and Integrys Energy seek here is already covered by the plain terms of the FirstEnergy Entities Settlement. In this regard, they also explain that the settlement resolves issues solely between FirstEnergy Entities and Exelon Entities and that the settlement does not impact non-settling parties' rights in any way. Therefore, they state that the settlement cannot bar the recovery of SECA amounts found to be due to Quest and Integrys Energy based on a subsequent Commission or court order or bar the recovery of any amounts found to be owing from any transmission owner.

b. **Commission Determination**

482. Quest and Integrys Energy ask that the Commission confirm that the FirstEnergy Entities Settlement cannot preclude the recovery of SECA amounts ultimately found to be due to Quest and Integrys Energy based on a subsequent Commission or court order. Settling Parties acknowledge that the confirmation that Quest and Integrys Energy request is already provided for by the plain terms of the settlement. We agree. Section 2.2 of the FirstEnergy Entities Settlement states that "[t]his [s]ettlement [a]greement does not in any manner affect the amount of lost revenue any non-settling transmission owner may claim against any other party to these proceedings…" The Commission previously

addressed similar concerns raised by Quest and found that a similar provision provided protection against adverse effects on non-settling parties.[548] Likewise, in these proceedings, we find that Article II, specifically section 2.2, provides protection against adverse effects on non-settling parties.

483. Moreover, we agree with Settling Parties that the settlement would resolve issues solely between FirstEnergy Entities and Exelon Entities and that the settlement would not impact non-settling parties' rights. Therefore, the settlement cannot preclude the recovery of SECA amounts ultimately found to be due to Quest and Integrys Energy based on a subsequent Commission or court order or preclude the recovery of any amounts found to be owing from any transmission owner.[549]

484. We find that the FirstEnergy Entities Settlement is, thus, uncontested and is, as well, fair and reasonable and in the public interest, and we will approve the FirstEnergy Entities Settlement. Our approval of the FirstEnergy Entities Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

485. This order will terminate Docket Nos. ER05-6-113, EL04-135-116, EL02-111-134, and EL03-212-130.

P. Other Issues Raised by the Parties

1. Retroactive Ratemaking

486. The Initial Decision states that it does not address whether the SECA constitutes retroactive ratemaking or violates the filed rate doctrine because these issues are pending before the Commission on rehearing and become moot due to the substantive findings in the Initial Decision.

487. AEP, Dayton, and Exelon assert that the Initial Decision correctly declines to address these matters because they were beyond the scope of the hearing.[550]

---

[548] December 2008 Order, 125 FERC ¶ 61,332 at P 13, 14 (*citing* July 2003 Order, 120 FERC ¶ 61,009 at P 19 & n.8, P 24, 29).

[549] We also note that Quest and Integrys Energy's claim that they may be adversely affected by the FirstEnergy Entities Settlement is unsubstantiated and speculative and, thus, does not raise issues of material fact. *Id.* P 15.

[550] AEP, Dayton, and Exelon Brief Opposing Exceptions to the Initial Decision at 13.

488. BG&E and Green Mountain argue, however, that the SECA as proposed in the compliance filings violates retroactive ratemaking and filed rate principles and that the Initial Decision errs in not considering these arguments.[551]

489. We agree with the Initial Decision's finding that these issues were outside of the scope of the hearing. Whether the SECA violates retroactive ratemaking or filed rate principles was an issue before the Commission on rehearing and is addressed in our companion order.

2. Timing of Compliance Filings

490. Classic PJM TOs argue that the Initial Decision errs in requiring compliance filings within thirty days of a Commission order on the Initial Decision. Classic PJM TOs argue that they need more time to collect and coordinate information to prepare accurate compliance filings.[552]

491. Compliance filings to revise the SECA charges to adopt the adjustments ordered herein are due within 90 days of the date of this order. We expect Midwest ISO TOs and the PJM transmission owners to work cooperatively to coordinate their filings, so that all adjustments are incorporated in a single round of compliance filings.

The Commission orders:

(A) The March 10 Partial Decision, April 13 Partial Decision, and Initial Decision are hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) Compliance filings are hereby due within 90 days of the date of this order, as discussed in the body of this order.

---

[551] *See, e.g.*, BG&E Brief on Exceptions to the Initial Decision at 2.

[552] Classic PJM TOs Brief on Exceptions to the Initial Decision at 16.

(C) The Settlements addressed in the body of this order are hereby approved, as discussed in the body of this order. The subdockets in which the settlements were filed are hereby terminated.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A – Parties and Abbreviations

Parties that submitted Briefs on Exceptions to the March 10 Partial Decision:

- American Electric Power Service Corporation (AEP),[553] Dayton Power and Light Company (Dayton), and Exelon Corporation (Exelon)[554]
- American Municipal Power – Ohio, Inc., (AMP-Ohio)
- FirstEnergy Service Company (FirstEnergy Service)[555]
- Midwest ISO Transmission Owners (Midwest ISO TOs)[556]
- Commission Trial Staff (Trial Staff)

---

[553] AEP submitted the filing on behalf of certain operating companies of AEP: Appalachian Power Co. (Appalachian Power), Columbus Southern Power Co. (Columbus Southern Power), Indiana Michigan Power Co. (Indiana Michigan Power), Kentucky Power Co. (Kentucky Power), Kingsport Power Co. (Kingsport Power), Ohio Power Co. (Ohio Power), and Wheeling Power Co. (Wheeling Power).

[554] Exelon submitted the filing on behalf of its operating subsidiaries: Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana (collectively, ComEd) and PECO Energy Co. (PECO).

[555] In this proceeding, FirstEnergy Service submits its filings on behalf of its affiliated operating public utility companies: Jersey Central Power and Light Co. (JCPL), Metropolitan Edison Co. (MetEd), and Pennsylvania Electric Co. (Penelec); Ohio Edison Co. (Ohio Edison), The Cleveland Electric Illuminating Co. (CEI), The Toledo Edison Co. (Toledo Edison), Pennsylvania Power Co.(Pennsylvania Power), and American Transmission Systems, Inc. (ATSI).

[556] Midwest ISO TOs consist of: Alliant Energy Corporate Services, Inc., on behalf of its operating company affiliate Interstate Power and Light Co.; Ameren Services Co. (Ameren), as agent for Union Electric Co., Central Illinois Public Service Co., Central Illinois Light Co., and Illinois Power Co.; American Transmission Co., LLC; ATSI; City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Duke Energy Shared Services, Inc. (Duke) for Cincinnati Gas & Electric Co., PSI Energy, Inc., and The Union Light, Heat and Power Co.; E.ON U.S. LLC for Louisville Gas and Electric Co. and Kentucky Utilities Co.; Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier); Indianapolis Power & Light Co.; Manitoba Hydro; Michigan Electric Transmission Co., LLC (METC); Minnesota Power and its subsidiary Superior Water, L&P; Montana-Dakota Utilities Co.; Northern Indiana Public Services Co. (NIPSCO); Northern States Power Co. (Minnesota) and Northern States Power Co. (Wisconsin); Otter Tail Corp.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Co.; and Wabash Valley Power Association, Inc.

<u>Parties that submitted Briefs Opposing Exceptions to the March 10 Partial Decision:</u>

- Aquila Merchant Services, Inc. (Aquila)
- The Detroit Edison Company and DTE Energy Trading, Inc. (DTET) (collectively, Detroit Edison)
- Duquesne Light Company (Duquesne)
- FirstEnergy Service
- AMP-Ohio; Craig-Botetourt Electric Cooperative, Four TDUs,[557] Nordic Marketing, LLC, Six Michigan Cities,[558] Virginia Municipal Electric Association No. 1, and Wisconsin Public Power, Inc. (collectively, Multiple TDUs); Green Mountain Energy Co. (Green Mountain); Michigan Public Power Agency (Michigan PPA); Michigan South Central Power Agency (Michigan SCPA); Ormet Primary Aluminum Corp. (Ormet); Quest Energy, LLC (Quest); and WPS Energy Services, Inc. (WPS Energy) (collectively, Indicated SECA Payers)

<u>Parties that submitted Briefs on Exceptions to the April 13 Partial Decision:</u>

- AEP,[559] Dayton, and Exelon[560]
- AMP-Ohio[561]
- Detroit Edison
- FirstEnergy Service
- Midwest ISO TOs
- Trial Staff

---

[557] Four TDUs include: Blue Ridge Power Agency, Central Virginia Electric Cooperative, Indiana Municipal Power Agency, and Old Dominion Electric Co. (Old Dominion).

[558] Six Michigan Cities include: City of Bay City, Michigan, (Bay City) and Michigan Public Power Rate Payers Association, which includes the Cities of Chelsea, Eaton Rapids, Hart, Portland, and St. Louis.

[559] AEP submitted the filing on behalf of certain operating companies of AEP. *See supra* n.550.

[560] Exelon submitted the filing on behalf of its operating subsidiaries. *See supra* n.551.

[561] AMP-Ohio filed a notice to withdraw its Brief on Exceptions to the April 13 Partial Decision, as applicable to its shift-to-shipper claim against Detroit Edison.

<u>Parties that submitted Briefs Opposing Exceptions to the April 13 Partial Decision:</u>

- AMP-Ohio
- Constellation Energy Commodities Group, Inc. (CCG)
- Duquesne
- FirstEnergy Service
- Michigan PPA and Michigan SCPA
- Ormet

<u>Parties that submitted Briefs on Exceptions to the Initial Decision:</u>

- AEP
- AEP, Dayton, and Exelon
- Allegheny Electric Cooperative, Inc. (Allegheny) and Southern Maryland Electric Cooperative, Inc. (Southern Maryland)
- AMP-Ohio, on behalf of itself and its members
- Baltimore Gas and Electric Company (BG&E)
- Certain Classic PJM Transmission Owners (Classic PJM TOs)[562]
- CCG and Constellation NewEnergy, Inc. (collectively, Constellation)
- Dayton
- Duquesne
- Exelon[563]
- FirstEnergy Service and FirstEnergy Solutions Corporation (FirstEnergy Solutions) (collectively, FirstEnergy)
- Green Mountain
- Michigan PPA
- Michigan SCPA
- Mirant Corporation (Mirant)
- Midwest ISO TOs[564]

---

[562] Classic PJM TOs for this filing consist of: West Penn Power Co., Monongahela Power Co. and The Potomac Edison Co. (collectively, Allegheny Power); PPL Electric Utilities Corp. (PPL); Pepco Holdings, Inc. on behalf of its affiliates Potomac Electric Power Co., Delmarva Power & Light Co., and Atlantic City Electric Co. (collectively, Pepco); Public Service Electric and Gas Co. (PSEG); BG&E; Rockland Electric Co. (Rockland); UGI Utilities, Inc. – Electric Division (UGI); Penelec, MetEd, and JCPL.

[563] Exelon submitted the filing on behalf of ComEd and PECO.

[564] For the purpose of this filing, Midwest ISO TOs also include International Transmission Co. (ITC).

- Ormet
- Quest, Strategic Energy, LLC (Strategic), and WPS Energy
- Southwestern Electric Cooperative, Inc. (Southwestern)
- Trial Staff
- Virginia Electric and Power Company (Dominion)

<u>Parties that submitted Briefs Opposing Exceptions to the Initial Decision:</u>

- AEP,[565] Dayton, and Exelon[566]
- Allegheny and Southern Maryland
- AMP-Ohio, on behalf of itself and its members
- BG&E
- Classic PJM TOs[567]
- CMS Energy Resource Management Company (CMS Energy)
- Constellation
- Detroit Edison
- Dominion
- Duquesne
- FirstEnergy
- Four TDUs
- Green Mountain
- Hoosier
- Michigan PPA
- Michigan SCPA
- Midwest Independent Transmission System Operator, Inc. (Midwest ISO)
- Midwest ISO TOs[568]
- Ormet
- Quest, Strategic, and WPS Energy
- Six Michigan Cities

---

[565] AEP submitted the filing on behalf of certain operating companies of AEP. *See supra* n.550.

[566] Exelon submitted the filing on behalf of its operating companies. *See supra* n.551.

[567] Classic PJM TOs for this filing consist of: Allegheny Power, PPL, Pepco, PSEG, BG&E, Rockland, and UGI.

[568] For the purpose of this filing, Midwest ISO TOs also include ITC.