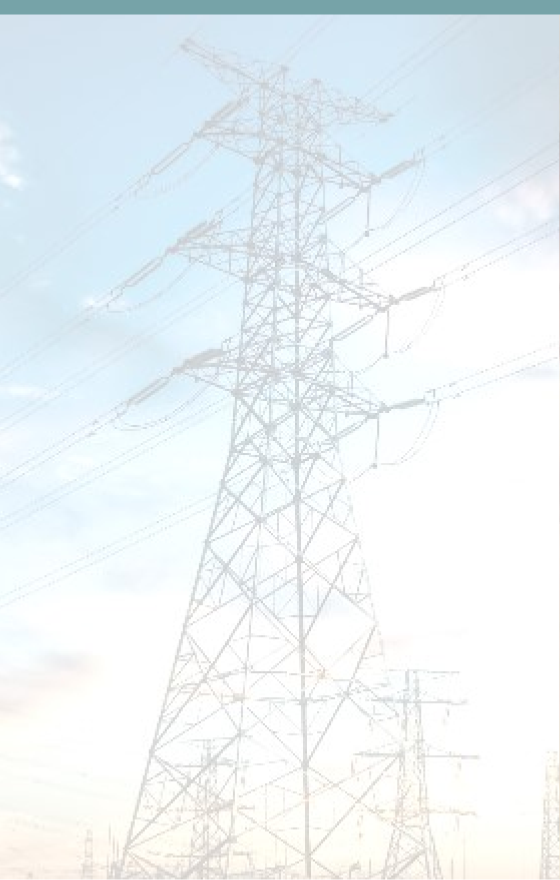
PREPARED BY GDS ASSOCIATES, INC.

Grant County PUD

Point-to-Point Transmission Rate Design

Summary Report

October 8, 2021



GDS Associates, Inc.
ENGINEERS & CONSULTANTS

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1 Development of Transmission Point-to-Point Rate

In anticipation of interest in solar delevopers seeking to interconnect to Grant County Public Utility District's ("Grant PUD") transmission system, the utility has requested that GDS Associates, Inc. ("GDS") assist in development of a transmission point-to-point ("P2P") rate that can be shared with potential developers and charged if an interconnection goes forward. Although Grant PUD does not have a formal Open Access Transmission Tariff ("OATT"), they do have network transmission customers and have an established Transmission Cost of Service ("TCOS") model for network service rates. Therefore, GDS was able to leverage the most recently approved TCOS to develop an appropriate P2P rate.

2 Transmission Cost of Service

The current TCOS was approved by the Grant PUD Commission in Fall 2020. The model uses methods considered the standard in the industry for calculating the revenue requirements for wholesale transmission service and ratemaking principles that been approved by the Federal Energy Regulatory Commission ("FERC"). Even though Grant PUD is not regulated by the FERC, their objective in developing the TCOS was to have a model that could receive FERC approval. The model is based on a 2018 test year.

The wholesale transmission service revenue requirement is composed of operations and maintenance expenses, depreciation expense, a return on rate base, and a discount for revenue credits. The TCOS utilizes Grant PUD financial data for the fiscal year ending 2018. As part of the development of the TCOS, a significant amount of effort was put into reviewing the underlying accounting information that is summarized in Grant PUD's general ledger. Therefore, review of the model will show certain adjustments to booked general ledger values in an attempt to more fairly assign costs and investment to the wholesale transmission function.

2.1 OPERATIONS AND MAINTENANCE EXPENSES

Transmission operating and maintenance expenses are booked in FERC Accounts 560 through 574. For the TCOS, all these costs were directly assigned to the transmission revenue requirements except for Account 565, which is "Transmission of Electricity by Others". In 2018, total transmission operations and maintenance expenses were $6,679,185[1], of which $581,439[2] was booked in Account 565 and removed from the TCOS as these costs are not related to the provision of wholesale transmission service. Therefore, operations and maintenance applicable to wholesale transmission was $6,097,746.

The TCOS also allocates a portion of administrative and general expenses to the transmission function. Of $31,614,708 in total administrative and general expenses in 2018, $4,588,297 were allocated to the

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[1] TCOS, Exhibit IV, Line 30, Column (c)

[2] TCOS, Exhibit IV, Line 20, Column (c)

transmission function. The administrative and general expenses in all accounts except Account 924, Property Insurance, was allocated based on wages and salaries. Property Insurances was allocated based on net plant in service[3]. The proposed allocation of these expenses are consistent with FERC's ratemaking guidelines.

As shown in Table 1, operating and maintenance expenses including allocated administrative and general costs equaled $10,686,043 for wholesale transmission.

TABLE 1: TRANSMISSION OPERATING AND MAINTENANCE EXPENSES

Item	Total Cost	Allocation	Allocator	Transmission Cost
Transmission O&M Net of 565	$6,097,746	Direct Assign	100.0%	$6,097,746
A&G Excluding Acct 924	$30,538,164	Wage & Salary	14.8%	$4,520,798
Acct 924 – Property Insurance	$1,076,544	Net Plant in Service	6.3%	$67,499
Total	$51,273,676			$10,686,043

2.2 DEPRECIATION EXPENSE

Depreciation expense includes $4,379,064 in directly assigned transmission plant depreciation plus an allocation of general plant and intangible plant depreciation. General plant-related depreciation expense is allocated to the transmission function based on wages and salaries. The transmission function was allocated $3,056,055 of the total intangible plant balance of $198,567,970.[4] The current rate of amortization of that asset is 4.46%, therefore 4.46% of the transmission share of intangible plant is included in revenue requirements for depreciation expense. Table 2 below provides a summary of depreciation expenses that are included in the TCOS.

TABLE 2: TRANSMISSION DEPRECIATION EXPENSE

Item	Total Cost	Allocation	Allocator	Transmission Cost
Transmission Plant	$4,379,064	Direct Assign	100.0%	$4,379,064
General Plant	$5,311,836	Wage & Salary	14.8%	$786,350
Intangible Plant	$8,849,329	4.46% of Alloc Plant	1.5%	$136,300
Distribution Plant	$19,942,592	None	0.0%	$0
Total	$38,428,811			$5,301,714

[3] Net plant in service is the booked cost of plant in service less accumulated depreciation.

[4] See TCOS, Exhibit V, Lines 1-10 for further details on this allocation

2.3 RETURN ON RATE BASE

A return on rate base is designed to include revenue recovery of the cost to capitalize investment in plant and to generate working capital. The return is computed by multiplying transmission rate base by a rate of return. Transmission rate base includes net plant in service plus working capital. Working capital includes materials and supplies, prepayments, and cash working capital (cash necessary to cover a short duration of operating expenses and account for the lag between incurrence of expenses versus recovery through rates).

For the transmission system, net plant in service totaled $116,708,213 and working capital totaled $4,009,072 for a total rate base of $120,717,285[5].

The return is based on a weighted average cost of capital that includes both the cost of debt and cost of equity associated with raising capital for Grant PUD. Although Grant PUD is a public utility with no shareholders, including a return on equity portion in the cost of capital is appropriate, as the utility still capitalizes investment in plant through a combination of debt and cash generated from margins, which is reflected as equity on the utility's balance sheet. For the most recently approved transmission cost of service, Grant PUD's Commission approved a weighted average cost of capital of 4.9%, consisting of a cost of debt of 3.5% and a cost of equity of 7.0%.

TABLE 3: RATE OF RETURN

Item	Capitalization Ratio	Cost of Capital	Weighted Average Cost of Capital
Long Term Debt	60.0%	3.5%	2.1%
Proprietary Capital	40.0%	7.0%	2.8%
Weighted Average Cost of Capital	100.0%		4.9%

Applying the 4.9% rate of return to $120 million in rate base results in a return of $5,915,147.

2.4 DISCOUNT FOR REVENUE CREDITS

Grant PUD receives wheeling revenue from several other utilities and these revenues are credited to the wholesale transmission revenue requirements. In 2018, revenue credits total $414,996 and included revenues from Puget Sound Energy ($165,252), Vantage Energy ($142,608), Seattle City Light ($53,568), and Tacoma Power ($53,568).

[5] See TCOS, Exhibit VII for further details on development of the rate base.

2.5 TOTAL REVENUE REQUIREMENT

Given each of the cost elements described above, the total wholesale transmission revenue requirements based on 2018 data is $21,487,908.

TABLE 4: TRANSMISSION REVENUE REQUIREMENTS

Item	Transmission Cost
O&M Expense	$10,686,043
Depreciation	$5,301,714
Return on Rate Base	$5,915,147
Revenue Credits	($414,996)
Total Cost to Serve	$21,487,908

3 Point-to-Point Rate

A network service charge, such as the transmission rate already charged by Grant PUD, is designed to allow use of the transmission system to serve load. A P2P rate likewise makes use of the transmission system but is intended for 3rd party sales or wheeling of power across the transmission system. In a P2P rate, an exact point of receipt and point of delivery is identified. For example, if a developer wished to build a solar power plant that would interconnect to the Grant PUD transmission system so that the power generated by the system could be sold to a third party, then the P2P would be the appropriate rate applied.

Grant PUD's transmission facilities that provide for firm point-to-point and network transmission services are the same. Therefore, regardless of the type of transmission service offered, there is no distinction in the corresponding costs of the transmission facilities that are used to compute the transmission revenue requirement. Consequently, the rate divisor that is used to compute the corresponding firm point-to-point and network rates (e.g., $/kW-mo.) includes both network and firm point-to-point transmission loads. This rate making approach has been approved and widely accepted by FERC.

The wholesale transmission revenue requirements computed in the TCOS, and approved by the Grant PUD Commission, provides the basis for computing a P2P rate. In order to compute a P2P rate, the transmission revenue requirements is divided by the average annual billing demand. During 2018, the Grant PUD billing demands ranged from 659.9 MW to 874.7 MW. Grant PUD's average system billing demand in 2018 is 742.5 MW[6]. Use of the 12-month average is consistent with methods approved by FERC.

The P2P rate is then derived by dividing revenue requirements by the average monthly billing demands of 742.5 MW and expressed on monthly, daily, and hourly bases. The rates are also grossed up by 3.984% to adjust for taxes[7]. The resultant P2P rate produced by the TCOS is $2.51 per kW-month.

TABLE 5: POINT-TO-POINT RATE

Item	Value	Units
Total Revenue Requirement	$21,487,908	
Billing Demand Divisor	742.5	MW
Monthly Rate Before Tax	$2.41	$/kW-month
Tax Adjustment	3.984%	
Monthly P2P Rate	**$2.51**	$/kW-month

[6] Details on development of the billing units can be found in the TCOS, Exhibit XII.
[7] The details supporting the computation of this tax rate can be found in the TCOS, Exhibit IX.

4 Reference Cases Before FERC

The methods used by GDS to compute the TCOS and the recommended point-to-point rate have been used by transmission service providers for several decades and are industry-standard approaches. The methods are employed by regulated and unregulated utilities throughout the United States, including in the western region and have been approved in many cases before FERC.

In the Appendix to this report, GDS has provided case information from three FERC orders that approved the methodology for utilities to use in developing their P2P rates. These same methodologies have been employed by Grant PUD and GDS do compute the P2P rates. The three FERC orders are for Entergy (1998), American Electric Power (1999), and Consumer's Energy (1999).

APPENDIX A

FERC OPINION NO. 430

Docket No. ER95-112

Entergy Services, Inc.

85 FERC ¶ 61,163

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 430

Entergy Services, Inc.	)	Docket Nos. ER95-112-000
	)	ER95-112-002
	)	ER95-112-007
	)	ER96-586-000
	)	ER96-586-002
	)	ER95-1001-001
Entergy Services, Inc. and	)	Docket Nos. EL95-17-000
Entergy Power, Inc.	)	EL95-17-002
Entergy Power Marketing Corp.	)	Docket No. ER95-1615-002
Entergy Services, Inc.	)	Docket No. ER96-2709-001

OPINION AND ORDER ON INITIAL DECISION
AND ON REHEARING AND APPROVING SETTLEMENT

Issued: October 30, 1998

Document Accession #: 19981103-0331   Filed Date: 10/30/1998

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Entergy Services, Inc.	)	Docket Nos. ER95-112-000 ER95-112-002 ER95-112-007 ER96-586-000 ER96-586-002 ER95-1001-001
Entergy Services, Inc. and Entergy Power, Inc.	)	Docket Nos. EL95-17-000 EL95-17-002
Entergy Power Marketing Corp.	)	Docket No. ER95-1615-002
Entergy Services, Inc.	)	Docket No. ER96-2709-001

OPINION NO. 430

APPEARANCES

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Zachary D. Wilson on behalf of The City of Benton, Conway Corporation, The City of North Little Rock, The City of Prescott, The Farmers Electric Cooperative Corporation, and West Memphis Arkansas Utilities Commission

Frederick H. Ritts, A. Hewitt Rose, and Sonnett C. Schmidt on behalf of Sam Rayburn G&T Electric Cooperative, and Northeast Texas Electric Cooperative

Robert C. McDiarmid, Bonnie S. Blair, and Lisa G. Dowden on behalf of Municipal Electric Association of Mississippi and Lafayette Utilities System

Earle H. O'Donnell and O. Julia Weller on behalf of Occidental Chemical Corporation

Ralph J. Gillis and Edward T. Angley on behalf of The Sam Rayburn Municipal Power Agency

Robert Weinberg, Michael R. Postar, and James N. Compton on behalf of South Mississippi Electric Power Association

John J. Bartus, Linda Lee, Stan Berman, Stephen Angle, and Richard J. Miles on behalf of the Federal Energy Regulatory Commission Trial Staff

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, Linda Breathitt,
and Curt Hébert, Jr.

Entergy Services, Inc.	) Docket Nos.	ER95-112-000 ER95-112-002 ER95-112-007 ER96-586-000 ER96-586-002 ER95-1001-001
Entergy Services, Inc. and Entergy Power, Inc.	) Docket Nos.	EL95-17-000 EL95-17-002
Entergy Power Marketing Corp.	) Docket No.	ER95-1615-002
Entergy Services, Inc.	) Docket No.	ER96-2709-001

OPINION NO. 430

OPINION AND ORDER ON INITIAL DECISION
AND ON REHEARING AND APPROVING SETTLEMENT

(Issued October 30, 1998)

In this opinion and order, the Commission addresses requests for rehearing and for clarification filed by numerous parties regarding two Commission orders in the above-referenced dockets. 1/ The Commission will also address the rehearing request of Entergy Services, Inc. (Entergy) filed in Docket No. ER96-2709-001. In addition, this case is before the Commission on exceptions to an Initial Decision issued on May 21, 1996. 2/ As discussed below, we will reverse in part and affirm in part the Initial Decision. Lastly, two partial settlements were filed on September 1, 1995 and on January 18, 1996, respectively. Both were certified as uncontested partial settlements by the Presiding Judge. 3/ The issuance of this opinion and order renders one of the settlements moot, and we will approve the other partial settlement, as discussed below.

1/ Entergy Services, Inc., 70 FERC ¶ 61,006 (1995), and Entergy Services, Inc., 74 FERC ¶ 61,137 (1996).

2/ Entergy Services, Inc., 75 FERC ¶ 63,015 (1996).

3/ 73 FERC ¶ 63,005 (1995) and 74 FERC ¶ 63,013 (1996).

I. Background

A detailed history of these proceedings is provided in the Initial Decision. 4/ In brief, these proceedings involve pre-Order No. 888 open access transmission tariffs filed under section 205 of the Federal Power Act 5/ by Entergy on behalf of certain of its public utility affiliates. 6/ The tariff filings at issue are the outgrowth of a prior Entergy pre-Order No. 888 open access transmission tariff filing in Docket No. ER91-569-000 and a court remand order in Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173 (D.C. Cir. 1994) (Cajun). 7/

A. January 6 Order

On October 31, 1994, Entergy, as agent for its affiliated Operating Companies, filed transmission tariffs in Docket No. ER95-112-000 (First Revised Tariffs). The First Revised Tariffs replaced and supplemented Entergy's initial tariff filing in Docket No. ER91-569-000 by incorporating changes in response to the Cajun remand order. These changes included the elimination of the stranded cost recovery provisions of the earlier tariffs.

On January 6, 1995, we accepted Entergy's First Revised Tariffs for filing, 8/ suspended them subject to refund, and set

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4/ 75 FERC at 65,044-49 (1996).

5/ 16 U.S.C. § 824d (1994).

6/ At the time the Initial Decision was issued, these public utility affiliates were called: Arkansas Power & Light Company, Gulf States Utilities Company, Louisiana Power & Light Company, Mississippi Power & Light Company, and New Orleans Public Service, Inc. (Operating Companies).

7/ On July 12, 1994, the court remanded the case to the Commission for further proceedings. Cajun, 28 F.3d 173. The court held that the Commission had erred in approving Entergy's transmission tariffs in Docket No. ER91-569-000 without first conducting a hearing on disputed issues of material fact concerning the impact of the transmission tariffs on Entergy's market power. Id. at 180. The court also expressed concern about the proposed recovery of stranded investment costs from customers, a point-to-point service limitation, and several other tariff provisions. See id.

8/ Entergy's Network Integration Service Transmission Tariff was made effective January 1, 1995. Entergy's Point-to-Point Transmission Service Tariff was made effective

(continued...)

them for hearing to, inter alia, develop a factual record and to make factual findings on whether the First Revised Tariffs were consistent with the comparability standard established in American Electric Power Service Corporation, 67 FERC ¶ 61,168 at 61,102 (1994). 9/

The January 6 order noted that by eliminating the stranded cost provision and the point-to-point service limitation, the First Revised Tariffs addressed two of the primary concerns of the Cajun remand order. 10/ The Commission stated that intervenors may pursue other concerns raised in Cajun at hearing. 11/ We concluded that "the procedures adopted in this order, in conjunction with our generic stranded cost proceeding, will provide the means for fully addressing the Cajun court's remand." 12/

B. February 14 Order

In the wake of the Commission's issuance of its open access transmission notice of proposed rulemaking, 13/ Entergy filed revised network and point-to-point transmission tariffs in Docket No. ER96-586-000 (Second Revised Tariffs). Entergy stated that the Second Revised Tariffs were intended to eliminate the differences between the First Revised Tariffs and the proposed open access transmission tariffs contained in the Open Access NOPR. The Second Revised Tariffs did not contain new proposed rates for transmission service, but rather adopted the rates already under investigation in Docket No. ER95-112-000. Entergy requested that the Second Revised Tariffs be made effective December 13, 1995, the date of the filing, and the rates be made subject to the outcome of Docket No. ER95-112-000. A companion

8/ (...continued)
January 9, 1995.

9/ Entergy Services, Inc., 70 FERC ¶ 61,006 (1995) (January 6 order).

10/ 70 FERC at 61,008, 61,013.

11/ Id. at 61,013-014.

12/ Id. at 61,014.

13/ Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 60 Fed. Reg. 17,662 (1995), FERC Statutes and Regulations ¶ 32,514 (1995)(Open Access NOPR).

filing in Docket No. ER95-1615-000 by Entergy Power Marketing (Entergy Marketing) sought authorization to sell power at market-based rates.

On February 14, 1996, we accepted the Second Revised Tariffs for filing, suspended them, subject to refund, and consolidated Docket No. ER96-586-000 with ER95-112-000 for the purposes of hearing and decision. 14/ In the February 14 order, we found that the non-rate terms and conditions of the Second Revised Tariffs were consistent with the Open Access NOPR tariffs and served to mitigate Entergy's transmission market power. We also approved Entergy Marketing's application for market-based rates.

Following the issuance of the February 14 order, a hearing was held in the consolidated proceeding, principally addressing certain issues involving the rates initially proposed in the First Revised Tariffs, as modified by a later settlement. (Prior to the hearing, the parties filed two partial settlements, which limited the scope of the hearing.) The Initial Decision was issued on May 21, 1996.

II. Requests for Rehearing

A. January 6 Order

The following parties filed for rehearing and/or clarification of the January 6 order: the South Mississippi Electric Power Association (SMEPA); Cajun Electric Power Cooperative, Inc. (Cajun) 15/ ; the Electricity Consumers Resource Council, et al. (ELCON); the Arkansas Public Service Commission (Arkansas Commission) and Louisiana Public Service Commission (Louisiana Commission); Occidental Chemical Corporation (OCC); Electric Clearinghouse, Inc. (ECI); and NorAm Energy Services, Inc. (NorAm).

1. Reciprocity Provision

SMEPA, ECI, and NorAm request rehearing regarding the First Revised Tariffs' reciprocity provisions. SMEPA argues that issues concerning the reciprocity provisions should have been set

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14/ Entergy Services, Inc., 74 FERC ¶ 61,137 (1996) (February 14 order).

15/ Cajun filed a motion on December 23, 1997, requesting that it be dismissed from these proceedings, among others. This motion was granted by letter order dated February 11, 1998. Therefore, we have not considered and will not address Cajun's briefs and pleadings herein.

for hearing. 16/ ECI and NorAm argue that the January 6 order should have rejected the proposed reciprocity provisions because the provisions require entities such as electric marketers that do not own transmission facilities to provide a transmission-facility-owning proxy to provide reciprocal service.

We find that the parties' requests for rehearing as to the reciprocity provisions contained in the First Revised Tariffs are moot. While we accepted the reciprocity provisions at issue on the grounds that we had previously accepted reciprocity provisions in other agreements, 17/ we do not disagree that we later required different reciprocity provisions in Order No. 888. 18/ However, as we note above, after a short locked-in period, the First Revised Tariffs were superseded by the Second Revised Tariffs, which were modeled on the Open Access NOPR tariffs and made subject to the outcome of the final rule in the Open Access NOPR proceeding. Moreover, at the time that the Second Revised Tariffs were filed, the parties agreed that the only matters remaining for hearing were rate, market power, and implementation issues. 19/ Thus, once the Second Revised Tariffs became effective, reciprocity provisions that conformed to the Open

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16/ SMEPA also seeks clarification that the Commission's rejection of the Entergy's "non-conforming" pricing proposal also applied to any "non-conforming aspects" of Entergy's conforming pricing proposal (namely, "and" pricing). We will so clarify. We did not, in accepting any aspect of Entergy's rates, accept "and" pricing, which is contrary to our precedent. See Northeast Utilities Service Company, 56 FERC ¶ 61,269 (1991), order on reh'g, 58 FERC ¶ 61,070, reh'g denied, 59 FERC ¶ 61,042 (1992), order granting motion to vacate and dismissing request for rehearing, 59 FERC ¶ 61,089 (1992), aff'd in relevant part and remanded in part, Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993); Pennsylvania Electric Company, 58 FERC ¶ 61,278 at 62,871-75, reh'g denied, 60 FERC ¶ 61,034 (1992), aff'd, Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

17/ January 6 order, 70 FERC at 61,010 & n.9.

18/ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

19/ See discussion of Settlement I, in Section IV.A, infra.

Access NOPR tariffs were on file, and the parties were in agreement that reciprocity was no longer at issue. Accordingly, we will dismiss as moot SMEPA's, ECI's, and NorAm's rehearing requests on this issue.

2. Impact on Retail Competition

On rehearing, ELCON contends that the January 6 order did not respond to arguments ELCON raised concerning the First Revised Tariffs' impact on retail competition. These arguments were: 1) the First Revised Tariffs' eligibility for service provisions place an unlawful restriction on the right of distribution-only systems to use the tariffs to serve former Entergy retail customers, and 2) the First Revised Tariffs thwart retail competition due to provisions that preclude the tariffs' use for retail wheeling or retail assignment of capacity.

We will dismiss as moot ELCON's request for rehearing regarding the impact on retail competition of certain non-rate terms and conditions in the First Revised Tariff. As we explained in conjunction with the reciprocity provisions of the First Revised Tariffs, after a short locked-in period, these tariffs were superseded by the Second Revised Tariffs, which were modeled on the Open Access NOPR tariffs and made subject to the outcome of the final rule in the Open Access NOPR proceeding. The parties also agreed at that time that the only issues remaining in contention were rate, implementation, and market power issues. Thus, once the Second Revised Tariffs became effective, ELCON's concerns regarding the impact of the First Revised Tariffs on retail competition were moot.

3. Stranded Cost Recovery

OCC seeks clarification to preclude Entergy from attempting to recover stranded costs arising from service taken under the First Revised Tariffs prior to the Commission's approval of an appropriate stranded cost provision. Alternatively, OCC argues that the issue of stranded cost recovery be addressed at hearing. OCC also seeks rehearing as to our finding that it would be premature to investigate whether an unknown stranded cost recovery provision, if any, would fail to mitigate Entergy's transmission market power or might otherwise be unjust and unreasonable or anticompetitive.

The Arkansas Commission and the Louisiana Commission also argue that this proceeding should be held in abeyance until the Commission's rulemaking on stranded costs is completed or, alternatively, the issue of stranded cost recovery should be addressed in this proceeding.

As we understand its request for clarification, OCC seeks assurance that if a party entered into a service agreement with

Entergy under the First Revised Tariffs prior to our approval of a stranded cost recovery provision, that party will not be required to pay any stranded costs during the term of the service agreement, even if we subsequently approve a revised tariff that allows Entergy to recover such costs.

As discussed above, Entergy removed the stranded cost recovery proposal from the First Revised Tariffs to comply with the court's decision in Cajun. We will therefore clarify that Entergy cannot, under the terms of the First Revised Tariffs, impose a stranded cost surcharge on OCC or any other customer. Because the issue is not presented to us herein, we decline to address whether Entergy would be entitled to collect a stranded cost surcharge from OCC or any other customer under the terms of any later open access transmission tariff. In light of this clarification, we will dismiss OCC's request for rehearing as moot. In addition, in light of the fact that a final rule has been issued on stranded cost recovery, we will dismiss as moot the Arkansas Commission's and the Louisiana Commission's requests for rehearing of our decision not to hold an evidentiary hearing on stranded cost recovery.

B. February 14 Order

The following parties requested rehearing and/or clarification of the February 14 order: the Municipal Energy Agency of Mississippi and the Lafayette Utilities System (collectively, MEAM/Lafayette); SMEPA; and the Cities of Benton, North Little Rock, Osceola, and Prescott, Arkansas, the Conway Corporation, the West Memphis Utilities Commission and the Farmers Electric Cooperative Corporation (collectively, ACC).

In addition to its request for rehearing, MEAM/Lafayette also filed an untimely motion to intervene in Docket No. ER96-1615-000. Although MEAM/Lafayette is a party to Docket Nos. ER96-586-000 and ER95-112-000, it is not a party to Docket No. ER95-1615-000 and seeks rehearing of our February 14 order as it applies to Docket No. ER95-1615-000. In support of its motion, MEAM/Lafayette contends that our February 14 order directly affects it in the dockets in which it is a party. For good cause shown, we will grant MEAM/Lafayette's untimely motion to intervene. 20/

Both Entergy and Entergy Marketing filed answers to requests for rehearing of the February 14 order. ACC replied to Entergy's answer. For good cause shown, we will accept the answers and the reply. Given the complexity of this proceeding, we believe that these additional filings assist the Commission by providing useful information and clarifying certain issues.

20/ 18 C.F.R. § 385.214(d) (1998).

MEAM/Lafayette, SMEPA, and ACC raise identical arguments on rehearing. They contend that our February 14 order improperly precluded a hearing on Entergy's market power as required by the court in Cajun. MEAM/Lafayette explains:

> The February 14 order appears to state with respect to Docket No. ER95-1615-000 (a market based sales rate request for Entergy Power Marketing Corp., in which [MEAM/Lafayette] and most of the other Intervenors in the ER95-112-000 docket have not previously been involved) that Entergy's decision to file open-access transmission tariffs consistent with the Commission's pro forma open access tariffs (superseding Docket No. ER95-112-000 tariffs as of December 13, 1995) serves to mitigate its transmission market power. That finding, in turn, was based upon a study as to the generation market power which has never been subject to the hearing process, but which was represented by Entergy in its filing in Docket No. ER95-1615-000 to be reliable because it was to be subject to the hearing process . . . . [21/]

MEAM/Lafayette, SMEPA, and ACC note that, based on the February 14 order's statements with regard to Docket No. ER95-1615-000, the Presiding Judge in Docket Nos. ER95-112-000 and ER96-586-000 concluded that the question of whether Entergy's Second Revised Tariffs mitigated Entergy's market power had been resolved and that there was no longer a need to litigate that issue. The parties argue that the Commission must grant rehearing and order a hearing addressing market power issues associated with Entergy's Second Revised Tariffs.

In the alternative, SMEPA seeks clarification of the February 14 order to permit the parties to Docket Nos. ER95-112-000 and ER98-586-000 to explore the full range of market power concerns associated with Entergy's Second Revised Tariffs. MEAM/Lafayette also seeks rehearing of the Commission's decision to defer litigation of the non-rate terms and conditions (implementation issues) in Entergy's Second Revised Tariffs until after the Commission issued its final rule in the Open Access NOPR. ACC also argues that Entergy's market power analyses are inadequate to justify approval of Entergy Marketing's market-based rate application because the market analyses which were filed in Docket Nos. ER91-569-000, EC92-21-000, ER92-806-000, ER95-112-000, and EL92-17-000 have never been subject to thorough

21/ MEAM/Lafayette Petition for Rehearing at 5 (footnote omitted).

scrutiny in those proceedings and because none of those proceedings is final. 22/

We will deny the rehearing requests of MEAM/Lafayette, SMEPA, and ACC. At the time the February 14 order was issued, the parties were on notice that the Commission intended to address on a generic basis such issues as comparability of service and its role in mitigating transmission market power. In the Open Access NOPR (issued April 7, 1995), we stated that the proposed rule would require all electric utilities owning or controlling transmission facilities to offer non-discriminatory open access transmission services under proposed pro forma tariffs for network and point-to-point services as a remedy for undue discrimination or anti-competitive effects. 23/ We explained:

> In the Open Access NOPR, the Commission is attempting to mitigate the core of market power not only for Entergy, but for all traditional public utilities: control over transmission access. The Commission is generically addressing all aspects of transmission market power, including those specifically identified by the Cajun court (e.g., point-to-point service limitation). Indeed, a fundamental purpose of the Open Access NOPR is to ensure the meaningful access to alternative suppliers that was identified by the Cajun court. Of utmost importance in mitigating market power is the Commission's non-discrimination (comparability) requirement, a requirement that had not been articulated at the time of the Commission's order under review in Cajun, and that is proposed to be codified in the Open Access NOPR proceeding. [24/]

We also stated that the Open Access NOPR would provide a record for addressing the court's concerns in Cajun regarding stranded costs, as well as an opportunity for all participants in the

22/ We note that ACC also contends that Entergy Marketing's February 29, 1996, filing in Docket No. ER95-1615-001 is inadequate. In that filing, Entergy Marketing purported to revise its sales tariffs to comply with our directives regarding the sharing of market information. We find that ACC's concerns regarding the February 29 compliance filing are beyond the scope of this opinion and order.

23/ FERC Stats. & Regs. ¶ 32,514 at 33,078.

24/ Id. at 33,105.

electric industry to present evidence and arguments concerning the recovery of stranded investment costs. 25/

In the wake of the Open Access NOPR, we issued three guidance orders that explained how the final rule would apply to pending cases, including the instant proceedings. 26/ In Guidance Order I, we explained that the terms and conditions contained in the Open Access tariffs were the minimum necessary to ensure transmission services that are not unduly discriminatory and directed, *inter alia*, the Presiding Judge in Docket Nos. ER95-112-000 to take into account the Commission's views in the NOPR. 27/

In Guidance Order II, we stated that:

> In sum, the Commission believes that the minimum non-price terms and conditions of non-discriminatory open-access transmission can best be determined in the Open Access NOPR proceeding, to the benefit of both utilities and customers. While we expect that individual cases may present circumstances requiring case-by-case litigation on rates and implementation issues, limiting the hearings to these utility-specific issues should permit more expedited resolution of such issues. This is in keeping with the Commission's objective of ensuring non-discriminatory open-access transmission services for all wholesale customers as soon as possible, and saving the resources of utilities, customers, and the Commission. [28/]

In Guidance Order III, we again emphasized that the terms and conditions of service applicable to pending or future open access tariff filings that substantially conformed to the Open Access NOPR tariffs (such as Entergy's Second Revised Tariffs)

25/ Id.

26/ Order Providing Guidance Concerning Pending and Future Proceedings Involving Non-Discriminatory Open access Transmission Services, 70 FERC ¶ 61,358 (1995) (Guidance Order I); American Electric Power Service Corporation, et al., 71 FERC ¶ 61,393 (1995) (Guidance Order II); American Electric Power Service Corporation, et al., 74 FERC ¶ 61,287 (1995) (Guidance Order III).

27/ Guidance Order I, 70 FERC at 62,052.

28/ Guidance Order II, 71 FERC at 62,543.

would be subject to the outcome of the final rule. 29/ Thus, our February 14 order merely reaffirmed this fact and clarified that the non-rate terms and conditions of Entergy's proposed transmission services would be resolved on a generic basis in the Open Access NOPR proceeding. 30/

Finally, we note the Cajun court has favorably noted our decision to address stranded costs in a generic proceeding. In denying OCC's motion to enforce the mandate in Cajun, the court stated that:

> Because Entergy Corporation has eliminated the provision for recovery of stranded investment costs from its tariffs, the conditions under which the court's mandate originally issued have since changed. In any event, the FERC's decision to address the stranded investment costs issue in a generic proceeding complies with the spirit of the court's mandate. [31/]

For these reasons, we reject MEAM/Lafayette's, SMEPA's, and ACC's claims that the February 14 order improperly precluded a hearing on Entergy's market power as required by Cajun, and deny rehearing on this issue.

C. December 17, 1997 Letter Order

On August 14, 1996, in Docket No. ER96-2709-000, Entergy, on behalf of the Entergy Operating Companies, filed an application for authorization to engage in wholesale bulk power sales at market-based rates. 32/ As a part of its application, Entergy

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29/ Guidance Order III, 74 FERC at 62,237.

30/ 74 FERC ¶ 61,137 at 61,486.

31/ Cajun Electric Power Cooperative, Inc. v. FERC, No. 92-1461, slip op. at 1 (D.C. Cir. filed May 8, 1996) (emphasis added); see also Louisiana Energy and Power Authority v. FERC, 141 F.3d 364 (D.C. Cir. 1998) (affirming the Commission's finding, without holding an evidentiary hearing, that a public utility's transmission market power had been adequately mitigated through its adoption of an open access transmission tariff that conforms to Order No. 888's generic requirements).

32/ Pursuant to Order No. 888, on July 9, 1996, in Docket No. OA96-158-000, Entergy filed its pro forma open access tariffs which superseded its Second Revised Tariffs,
(continued...)

filed revisions to its Rate Schedule SP, under which it made market-based power sales. On December 17, 1997, a letter order was issued by the Director, Division of Rate Applications, Office of Electric Power Regulation, accepting the revisions for filing (December 17 order). The order stated that "inasmuch as Entergy's market-based rates are being considered in Docket Nos. ER91-569-000, [et al.], revenues collected under the tariff shall be subject to refund and subject to the outcome of the proceedings in Docket No. ER91-569-000, et al."

On rehearing, Entergy argues that the Commission erred in making Rate Schedule SP subject to refund. It claims that the rates could be subject to refund only in Docket No. EL95-17-000, 33/ in which, Entergy maintains, the fifteen-month refund period ended on June 14, 1996, prior to the effective date of its proposed revisions in Docket No. ER96-2709-000.

As we explain herein, we find that there is no need to conduct any further proceedings in Docket No. EL95-17-000 (Section III.B.) and that all issues involving Energy's transmission market power under the Second Revised Tariffs have been resolved (Sections II.B. and III.B.). In addition, Entergy's Order No. 888 open access compliance tariff became effective on July 9, 1996, approximately one month before the revisions to Rate Schedule SP were filed. Therefore, we will grant rehearing, and clarify that there is no refund liability in Docket No. ER96-2709-000.

III. Initial Decision

Briefs on and opposing exceptions to the Initial Decision were filed by Entergy; Northeast Texas Electric Cooperative, Inc. and Sam Rayburn G&T Electric Cooperative (collectively,

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32/ (...continued)
effective July 9, 1996.

33/ Docket No. EL95-17-000 is an investigation under section 206 of the Federal Power Act involving Entergy's market-based power sales. It was established in response to the Commission's concerns about its ability to order refunds of Entergy's market-based power sales rates under section 205 in the event that the Commission were to conclude that Entergy's transmission tariffs did not provide for comparable service, and thus did not adequately mitigate Entergy's transmission market power. January 6 order, 70 FERC at 61,013.

NTEC/SRG&T); Cajun; 34/ OCC; SMEPA; ACC; MEAM/Lafayette; and Commission Trial Staff (Trial Staff).

Having reviewed the record, the Initial Decision, and the briefs, we find that the Initial Decision properly resolved all outstanding issues not discussed herein. 35/ Accordingly, to the extent an issue is not discussed herein, we shall affirm and adopt the Initial Decision as our own decision on that issue.

A. Daily and Hourly, Firm and Non-Firm Rate Design for Point-to-Point Service

Entergy originally proposed to calculate the daily firm and non-firm rate based on a five-day week and the hourly firm and non-firm rate based on a sixteen-hour day (4,160). 36/ During the course of the proceeding, Entergy proposed to include an off-peak hourly rate calculated by dividing the annual rate by the total number of hours in a year (8,760). Entergy's original rate design would remain applicable to the on-peak period.

1. Initial Decision

The Initial Decision found that Entergy had not supported its proposed on-peak/off-peak rate differential and ordered that Entergy develop its hourly rate using the total number of hours in a year (8,760) for all daily and hourly firm and non-firm transmission service. 37/ The Initial Decision found that the cases Entergy and Trial Staff used to support the on-peak/off-peak proposal were settlements and therefore could not be used as precedent. In addition, the Initial Decision concluded that

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34/ As previously noted, Cajun has been dismissed from these proceedings, and we have not addressed its briefs and pleadings herein.

35/ As noted in the Initial Decision, 75 FERC at 65,048, the Revised Joint Final Stipulation of Issues lists the issues to be decided at hearing. We address herein only two: daily and hourly firm and non-firm rate design for point-to-point service and market power. We summarily affirm the Initial Decision's findings on the following issues: calculation of the denominator for the transmission component of non-firm point-to-point service; whether rates for network integration service should be determined on a single-system or subfunctionalized basis; and applicability and calculation of a local facilities rate.

36/ In support, Entergy cites Appalachian Power Company, 39 FERC ¶ 61,296 (1986) (Appalachian or "AEP method").

37/ 75 FERC at 65,054.

Entergy had failed to substantiate the nature of on-peak transmission usage on the Entergy system. 38/

2. Exceptions

On exceptions, Entergy and Trial Staff argue that Commission precedent and the facts in this case support Entergy's on-peak/off-peak proposal. They cite to a number of cases in which the Commission accepted for filing, without hearing or suspension, non-firm transmission rates calculated using the "AEP method". 39/ Trial Staff contends that the Commission's action in the these proceedings indicates a willingness on the Commission's part to use on-peak/off-peak pricing as a way to resolve the competing interests presented in evaluating short-term transmission rates. 40/ In addition, Entergy argues that it has shown through the unrefuted testimony of its witness that the vast majority of point-to-point transmission usage occurred during peak hours. 41/

SMEPA opposes the exceptions of Entergy and Trial Staff on this issue. SMEPA argues that case law does not support the use of the "AEP method" in this case and that its use by Entergy would amount to impermissible value-based pricing. SMEPA further argues that the "AEP method" requires data support which Entergy has not provided. 42/

3. Discussion

We will reverse the Initial Decision's findings regarding the proper rate design for daily and hourly firm and non-firm transmission rates for point-to-point service. We will accept Entergy's modified proposal to calculate its daily firm transmission rate based on a five-day week and its hourly firm transmission rate based on a sixteen-hour day. Consistent with the requirements of the AEP method, we will require that the total charge in any week for daily service cannot exceed the stated weekly rate multiplied by the maximum daily capacity reservation during such week. The total charge in any day for hourly service cannot exceed the stated daily rate multiplied by the maximum hourly capacity reservation during such day. In

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38/ Id. at 65,053.

39/ Entergy Brief on Exceptions at 5 and Trial Staff Brief on Exceptions at 11 (and cases cited therein).

40/ Trial Staff Brief on Exceptions at 7.

41/ Entergy Brief on Exceptions at 8.

42/ SMEPA Brief Opposing Exceptions at 48-81.

addition, the total demand charge in any week pursuant to a reservation of hourly or daily service cannot exceed the weekly rate multiplied by the maximum hourly capacity reservation in any hour during such week. 43/ Correspondingly, the daily and hourly on-peak non-firm transmission rates are ceiling rates capped at the respective firm rates. In addition, we will accept Entergy's off-peak pricing proposal for daily and hourly firm and non-firm transmission rates based on 8,760 hours (365 days for daily service).

Both the case law cited by SMEPA and the findings of the Initial Decision focus on the calculation of an hourly non-firm transmission rate. However, these findings are not applicable to the calculation of daily and hourly firm transmission rates. Firm transmission service is priced to recover 100 percent of the fixed costs associated with providing the service. As such, Entergy's reliance on the "AEP method" is consistent with the premise that firm transmission service should be priced based on the peak periods of usage on the transmission system. In addition, the price caps on the daily and hourly firm rate will ensure that Entergy does not recover more than 100 percent of its transmission-related fixed costs.

Furthermore, the use of daily and hourly firm rates as a ceiling for the respective non-firm rates is reasonable and consistent with Commission precedent. The Commission has refused to require non-firm transmission ceiling rates be lower than the firm transmission rates so long as the transmission provider's open access tariff offers the ability to discount the non-firm transmission rate from the stated firm ceiling rate. 44/

Entergy's off-peak non-firm rate also is reasonable and consistent with Commission precedent. In IES Utilities, 45/ we approved a time-differentiated non-firm rate design with on-peak rates based on a divisor of 4,160 hours and off-peak rates based

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43/ See pro forma tariff, Schedule 7 (Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service) and Schedule 8 (Non-Firm Point-to-Point Transmission Service); Order No. 888-A at 30,540-41.

44/ See Order 888 at 31,743-44; American Electric Power Service Corporation, 82 FERC ¶ 61,090 (1998); Northeast Utilities Service Company, 84 FERC ¶ 61,158 (1998).

45/ IES Utilities, Inc. et al., Opinion No. 419, 81 FERC ¶ 61,187 (1997), order denying reh'g, granting clarification in part and denying clarification in part, 82 FERC ¶ 61,089 (1998), appeal pending, No. 98-1101 (D.C. Cir.) (IES Utilities).

on a divisor of 8,760 hours, 46/ which is similar to Entergy's proposal in this case. In contrast, in Northern States, 47/ we rejected the use of the 4,160 hour rate design for non-firm transmission service because the Commission found that the company had not demonstrated that non-firm transmission usage would be limited to on-peak periods. 48/ Under Entergy's proposal, the issue of when non-firm service will be provided is no longer relevant because off-peak service will no longer be charged an on-peak rate. The use of a separate on-peak/off-peak rate design as proposed by Entergy obviates the need to provide the demonstration required in Northern States.

B. Market Power

1. Initial Decision

Applying the standards then in effect, the Initial Decision found that Entergy's Second Revised Tariffs provided for comparable service and adequately mitigated Entergy's transmission market power. Furthermore, the Initial Decision determined that the transmission rates, as modified in the Initial Decision, will ensure the provision of comparable transmission service. The Initial Decision found that the Commission's issuance of Order No. 888 removed any doubt as to whether Entergy's open access transmission tariffs mitigate transmission market power. 49/

2. Exceptions

On exceptions, MEAM/Lafayette, SMEPA, OCC, and ACC argue that the Initial Decision improperly narrowed the scope of the market power issue by striking testimony, thus preventing a full examination of the impact of Entergy's tariffs on its transmission market power. OCC requests that the Commission reverse the Initial Decision's findings and order a full evidentiary hearing on the issue of whether Entergy's tariffs are

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46/ IES Utilities, 81 FERC at 61,833-34.

47/ Northern States Power Company (Minnesota and Wisconsin), Opinion No. 383, 64 FERC ¶ 61,324 (1993), order denying reh'g and granting clarification, 74 FERC ¶ 61,106 (1996) (Northern States).

48/ Northern States, 74 FERC at 63,401-02.

49/ 75 FERC at 65,059.

sufficient to mitigate its transmission market power in the presence of a stranded cost recovery provision. 50/

SMEPA argues that the issue of Entergy's market power must include an analysis of the rate impact associated with Entergy's apparent suggestion that existing transmission agreements must be terminated prior to service being provided under open access transmission tariffs. 51/ In addition, SMEPA asserts that the Network Operating Agreement (NOA) filed by Entergy as part of the network integration service tariff will contribute to Entergy's ability to exercise market power. 52/

ACC argues that the requirements of Order No. 888 do not provide sufficient assurance that Entergy's market power will be mitigated and that Order No. 888 does not sufficiently answer the concerns raised by the court in Cajun. ACC contends that the Initial Decision erred by striking testimony discussing two examples of Entergy's market power. 53/ ACC argues that these issues should be addressed in order to gain a complete picture of the market power implications of Entergy's proposed tariffs. 54/

Trial Staff and Entergy oppose these exceptions. They each argue that the Initial Decision correctly narrowed the scope of the proceeding. In addition, they assert that Order No. 888 and the Commission's findings in Entergy Services, Inc., 74 FERC ¶ 61,137 at 61,487 (1996), fully support the conclusion that Entergy has fully mitigated any transmission market power it may have possessed.

50/ OCC Brief on Exceptions at 14.

51/ SMEPA Brief on Exceptions at 31.

52/ Aside from the market power issue, SMEPA argues that the Presiding Judge, by striking SMEPA's testimony on the NOA, precluded any consideration as to whether or not the NOA is just and reasonable. Id. at 32.

53/ ACC argues that two factors demonstrate that Entergy is abusing its market power: (1) Entergy's refusal to honor a 1989 Memorandum of Understanding between an Entergy Operating Company and ACC, and (2) the uncertainty over the status of existing ACC/Entergy agreements in the event that ACC were to take service under Entergy's pro forma tariffs.

54/ ACC Brief on Exceptions at 8-20.

3. Discussion

We affirm the Initial Decision's findings that, for the locked-in period during which they were in effect, 55/ Entergy's Second Revised Tariffs met the Commission's then-existing standards for comparability of service and mitigation of transmission market power. We also affirm the Presiding Judge's evidentiary rulings striking evidence related to transmission market power issues.

In discussing the requests for rehearing of the February 14 order with regard to the issue of transmission market power (Section II.B.), we took note of the Commission's decision, as explained in the Open Access NOPR and the related Guidance Orders, to address on a generic basis the issues of comparability of service and its role in mitigating transmission market power and to make all pending proceedings in which utilities had filed proposed open access transmission tariffs, including Docket Nos. ER95-112-000 and ER96-586-000, subject to the outcome of the final rule in the Open Access NOPR. In Guidance Order III, the Commission reiterated that the non-rate terms and conditions of those tariffs would be addressed in the Open Access NOPR proceeding. Thus, non-rate terms and conditions were not to be litigated in case-specific proceedings. 56/

We therefore find that the Initial Decision appropriately narrowed the scope of the transmission market power issue. To the degree that the exceptions of SMEPA, ACC, and OCC attack the Commission's decision to address the issues of comparability of service, mitigation of transmission market power, and stranded cost recovery in a generic proceeding, these exceptions constitute a collateral attack on the Commission's determinations in Order No. 888 and are rejected. We further find that based on the record in this proceeding, the Guidance Orders, and Order No. 888, there is no need for any further proceedings in Docket No. EL95-17-000, a determination which, as noted in the Initial Decision, 57/ has been held in abeyance pending resolution of the proceedings in Docket Nos. ER95-112-000 and ER96-586-000.

55/ As previously noted, the Second Revised Tariffs were superseded by Entergy's Order No. 888 open access compliance tariff as of July 9, 1996.

56/ 74 FERC at 62,238. See also February 14 order, 74 FERC at 61,486 (all non-rate terms and conditions of Entergy's Second Revised Tariffs will be subject to the outcome of the Open Access NOPR proceeding).

57/ 75 FERC at 65,045; see n.33, supra.

With regard to the NOA filed with the network service tariff, while we affirm the Presiding Judge's rejection of SMEPA's testimony concerning the justness and reasonableness of the NOA in this proceeding, we note that this is without prejudice to SMEPA raising the issue at a later date in a separate proceeding. The Second Revised Tariffs filed in these proceedings have been superseded by Entergy's open access compliance tariffs filed in Docket No. OA96-158-000. In the order accepting Entergy's compliance tariffs, we noted that NOAs would be subject to further review when filed for individual service. 58/ Therefore, SMEPA may challenge the justness and reasonableness of Entergy's NOA if and when SMEPA decides to become a network customer of Entergy.

C. Credits for Customer-Owned Transmission Facilities

Entergy had proposed that a network customer receive a credit for existing transmission facilities that are "integrated with and support Entergy's transmission system" consistent with the Open Access NOPR. Entergy proposed credits only for Cajun's facilities, but not for MEAM/Lafayette and NTEC/SRG&T.

1. Initial Decision

Noting that the Commission had issued its order in Florida Municipal Power Agency v. Florida Power and Light Company, 74 FERC ¶ 61,006 (1996), petition for review filed, No. 96-1076 (D.C. Cir. March 3, 1996) (FMPA) prior to the commencement of the trial, the Presiding Judge provided the parties with an opportunity to supplement the record to address the integration test established in FMPA. The Initial Decision ruled that Entergy's criteria were consistent with the integration test established in FMPA. The Initial Decision relied upon extensive evidence, including load flow analyses, to determine that the Commission's criteria for such credits had not been met for customers other than Cajun. 59/

2. Exceptions

MEAM/Lafayette and NTEC/SRG&T filed exceptions. They each argue against the Commission's treatment of credits for customer-owned transmission facilities in Order No. 888 as well as Entergy's application of those principles in the instant case. Both argue in favor of the "rate base" test recently rejected by the Commission. NTEC/SRG&T contends that the Initial Decision

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58/ AEP Service Corporation, et al., 78 FERC ¶ 61,070 at 61,264 (1997), order on reh'g, Carolina Power & Light Co., et al., 82 FERC ¶ 61,204 (1998).

59/ 75 FERC at 65,054-58.

applies the Commission's policy too rigidly. MEAM/Lafayette point out that the record in the case contains several examples of Entergy relying on MEAM/Lafayette transmission facilities, which, they argue, supports their claims of integration under Commission precedent and their eligibility for credits for customer-owned transmission facilities under of Entergy's network service tariff.

On exceptions, Trial Staff argued that reaching the issue of credits was premature. However, on January 2, 1997, Entergy and SRG&T filed a joint stipulation and joint motion to reopen and supplement the record to show that SRG&T was a network customer of Entergy as of January 1, 1997. Entergy and SRG&T contend that the issue of a credit for customer-owned transmission facilities is now ripe for decision in this proceeding. In response, Trial Staff withdrew its objection to the Commission resolving SRG&T's credit issue herein.

We will reopen the record to take notice that SRG&T is a network customer of Entergy as of January 1, 1997. Nonetheless, as we explain below, we affirm the Initial Decision's findings regarding the issue of credits for customer-owned transmission facilities.

3. Discussion

The Initial Decision properly applied the Commission's policy on credits for customer-owned transmission facilities as described in FMPA and Order Nos. 888 and 888-A. Based on load flow studies and other evidence, 60/ the Presiding Judge correctly determined that the existing MEAM/Lafayette and SRG&T facilities failed to meet the Commission's criteria for integrated facilities and therefore were not eligible for credits.

Entergy performed a base case load flow study of its system under normal situations and contingency conditions. Then, Entergy examined how those same base and contingency case conditions would change if Entergy were not connected to the customer systems in question. The results showed that Entergy's other wholesale and retail customers would not be negatively affected if the customer-owned transmission facilities were not present. In other words, the evidence on which the Presiding Judge relied shows that the customer-owned facilities of MEAM/Lafayette or SRG&T do not provide any support to the Entergy system, but rather, the 230 kV Lafayette facilities between the Doc Bonin and Flanders substations interconnect and support

60/ See Exh. Nos. ESI-26 and ESI-28.

another system (that of Central Louisiana Electric Company). 61/ Thus, under the Commission's precedent, MEAM/Lafayette and SRG&T are not eligible for credits under Entergy's network tariff. Accordingly, we affirm the Initial Decision on this issue.

IV. Settlements

As previously noted, the Presiding Judge certified two uncontested partial settlements to the Commission for our approval. We will briefly describe these proposed settlements and our findings relating thereto below.

A. Settlement I

On September 1, 1995, Entergy filed an offer of partial settlement (Settlement I). Settlement I does not address rate issues, but rather resolves certain non-rate issues by incorporating non-rate terms and conditions drawn, with two minor distinctions, from the Open Access NOPR tariffs. 62/ Settlement I also reserved certain issues for hearing. (Some of these issues were the subject of the Initial Decision.)

Entergy requested that proposed effective date for the Settlement I tariffs coincide with the effective date of the Second Revised Tariffs filed in Docket No. ER96-586-000 (December 13, 1995). That is, Entergy requested that the Settlement I tariffs be made effective for a nominal period, to be immediately superseded by the Second Revised Tariffs, effective December 13, 1995. According to Entergy, this was intended to protect the parties' interests in the litigated proceeding. 63/

B. Settlement II

On January 18, 1996, as completed on January 29, 1996, Entergy filed a second offer of partial settlement. Settlement II resolves various rate issues including revised rate formulas for the Second Revised Tariffs and several implementation issues concerning redispatch procedures. The settlement rates, which were made subject to refund and subject to the outcome of the hearing, were proposed to become effective on the effective dates for the First Revised Tariffs, namely, January 1, 1995, for the

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61/ Exh. No. ESI-29.

62/ The exceptions are: (1) only one ancillary service is offered (scheduling and dispatch service); and (2) network integration service customers are allowed to make off-system sales (using as-available transmission service up to their ratio share) at no charge.

63/ Docket No. ER96-586-000 Transmittal Letter at 6.

network tariff and January 9, 1995, for the point-to-point tariff.

C. Comments

Numerous parties filed comments in support of the settlements. 64/ However, OCC filed comments opposing both settlements. The basis of OCC's objection was its opposition to the Commission's ruling in the January 6 order that the stranded cost recovery issue should be decided in the Commission's generic stranded cost rulemaking proceeding rather than the case-specific, instant proceeding. While SMEPA supports both settlements, it objects to Entergy's implementation of the parties' agreement in principle concerning revenue credits from direct assignment facilities.

D. Discussion

1. OCC's Objections

We will approve the settlements notwithstanding OCC's opposition. The Presiding Judge, in analyzing OCC's comments on Settlement I, noted that:

> consistent with the Commission's hearing order and the NOPR, the [issue of the] recovery of stranded investment costs was beyond the scope of the hearing. [65/]

He ruled, therefore, that OCC, in objecting to Settlement I on the ground that a hearing was required on that issue did not present a genuine issue of material fact and therefore held that Settlement I was a partial uncontested offer of settlement. 66/

We agree with the Presiding Judge that OCC's objections concern the propriety of the January 6 order and thus should not preclude approval of the settlements. We address and clarify herein OCC's request for clarification or rehearing of the January 6 order, and we will not address the same arguments in the context of the settlements.

64/ Comments in support of the settlements were filed by Trial Staff, Entergy, SMEPA, ACC, Cajun, NTEC/SRG&T, MEAM, American Forest Paper Association, ECI, and Louisiana Electric Power Authority.

65/ 75 FERC at 65,047.

66/ Id.

2. Settlement I

Entergy requests that the Settlement I Tariffs be nominally suspended and immediately superseded by Entergy's Second Revised Tariff filed in Docket No. ER96-586-000. Entergy's sole procedural reason for requesting that the Settlement I Tariffs still be accepted for filing -- to protect the parties' interests in the litigated proceeding -- is now unnecessary because the hearing has concluded. Accordingly, we find that there is no need for us to address Settlement I, and we will not accept for filing the Settlement I tariffs.

3. Settlement II

With respect to Settlement II, our analysis indicates that Settlement II reflects a reasonable resolution of a number of implementation and ratemaking issues, including the revenue credit issue raised by SMEPA. Accordingly, we will accept Settlement II as filed.

All parties agree that Entergy's transmission system revenue requirement should be reduced to reflect revenue credits associated with direct assignment facilities. SMEPA objects to Entergy's implementation of the agreement in principle.

SMEPA's objection to Entergy's revenue crediting proposal is related to a stipulation to remove step-up transformers from the settlement rates. To implement this stipulation, Entergy's settlement rate formula, among other things, apportions transmission expenses based on the ratio of transmission plant (excluding generator step-up transformers) divided by total transmission plant in service. In this manner, Entergy removes a portion of transmission expenses (based on plant ratios) from the derivation of the settlement tariff rates. Entergy proposes to credit revenues from directly assigned facilities based on the same plant ratios. SMEPA argues that Entergy's proposal improperly excludes some of the revenues associated with direct assignment facilities from the derivation of the settlement rates. SMEPA proposes that all such revenues should be credited in the settlement rate formula. In response, Entergy notes that generator step-up transformers account for 1.7 percent of its total transmission plant: therefore, according to Entergy, SMEPA's proposed adjustment will have a de minimis effect on the proposed settlement rates.

Entergy's revenue credit proposal is consistent with its treatment of transmission expenses (i.e., operating and maintenance, depreciation, administrative and general, and taxes) in the rate formula. Furthermore, Entergy's proposal is consistent with the allocation of all other transmission revenues for short-term transmission service. SMEPA has not demonstrated that the settling parties intended to make an exception in the settlement rate formula for the treatment of direct assignment revenues. Moreover, SMEPA's proposed adjustment creates a mismatch by developing transmission rates with a larger revenue credit vis-a-vis allocated transmission expenses. Therefore, we reject SMEPA's adjustment. 67/

The Commission orders:

(A) SMEPA's, ECI's, NorAm's, OCC's, the Arkansas Commission's, the Louisiana Commission's, and ELCON's requests for rehearing and/or clarification of the January 6 order are hereby dismissed as moot, as discussed in the body of this order.

(B) MEAM/Lafayette's untimely motion to intervene is hereby granted, as discussed in the body of this order.

(C) Entergy's and Entergy Marketing's answers to requests for rehearing and ACC's reply thereto are hereby accepted for filing, as discussed in the body of this order.

(D) MEAM/Lafayette's, SMEPA's, and ACC's requests for rehearing and clarification of the February 14 order are hereby denied, as discussed in the body of this order.

(E) Entergy's request for rehearing of the December 17 order is hereby granted, as discussed in the body of this order.

(F) The Initial Decision issued on May 21, 1996 in this proceeding is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(G) Settlement II, as certified by the Presiding Judge, is hereby approved.

(H) Within 60 days of the date of issuance of this order, Entergy shall make a compliance filing with the Commission. However, if a request for rehearing is filed, Entergy shall make its compliance filing within 30 days of the date the Commission disposes of the request for rehearing.

(I) Within 30 days of the Commission's acceptance of Entergy's submittal required in Ordering Paragraph (H) above, Entergy shall make refunds with interest calculated pursuant to 18 C.F.R. § 35.19a (1997).

67/ Because we are summarily affirming the Initial Decision's rolled-in, single-system approach for calculating the network service rate, we need not address SMEPA's objection to Entergy's proposed allocation of revenue credits under the alternative bifurcated approach for calculating the network service rate.

(J) Entergy is hereby informed of the rate schedule designations shown on Attachment A.

By the Commission.

(S E A L)

David P. Boergers

David P. Boergers,
Secretary.

Attachment A

Entergy Operating Companies
Docket No. ER95-112-000
Rate Schedule Designations

Designation	Description / Effective Date
(1) First Revised Sheet Nos. 102 - 110 under FERC Electric Tariff, Second Revised Volume No. 1 (Supersede Original Sheet Nos. 102 - 110)	Revisions to Point-to-Point Transmission Service Tariff Effective: January 9, 1995
(2) First Revised Sheet Nos. 113 - 119 under FERC Electric Tariff, Second Revised Volume No. 1 (Supersede Original Sheet Nos. 113 - 119)	Revisions to Point-to-Point Transmission Service Tariff Effective: January 9, 1995
(3) Original Sheet Nos. 68 - 90 under FERC Electric Tariff, First Revised Volume No. 2	Revisions to Network Integration Service Tariff Effective: January 1, 1995

Document Content(s)

APPENDIX B

FERC OPINION NO. 440

Docket No. ER93-540

American Electric Power

88 FERC ¶ 61,141

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 440

American Electric Power Service Corporation	)	Docket No. ER93-540-006

OPINION AND ORDER AFFIRMING IN PART AND
REVERSING IN PART INITIAL DECISION

Issued: July 30, 1999

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation) Docket No. ER93-540-006

OPINION NO. 440

APPEARANCES

Edward J. Brady, and Kevin F. Duffy, on behalf of American Electric Power Service Corporation.

James N. Horwood, Mark S. Hegedus, and John W. Bentine, on behalf of American Municipal Power-Ohio, Inc., and Indiana Municipal Power Agency.

Frederick H. Ritts, and Julie B. Greenisen on behalf of Blue Ridge Power Agency.

Don F. Morton, Charles W. Ritz, III, and James A.L. Buddenbaum, on behalf of Wabash Valley Power Association, Inc.

John J. Bartus, Warren C. Wood, Richard L. Miles, and Stan Berman, on behalf of the Federal Energy Regulatory Commission Trial Staff.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

American Electric Power Service Corporation) Docket No. ER93-540-006

OPINION NO. 440

OPINION AND ORDER AFFIRMING IN PART,
AND REVERSING IN PART, INITIAL DECISION

(Issued July 30, 1999)

I. INTRODUCTION

This proceeding is before the Commission on exceptions to an Initial Decision issued in this proceeding on August 7, 1997 (Initial Decision). 1/ In this order, with certain enumerated exceptions, we affirm the findings of the presiding administrative law judge (judge).

II. BACKGROUND

This proceeding began when American Electric Power Service Corporation (AEPSC) 2/ filed a transmission service and ancillary services tariff for Commission approval. The proposed tariff offered firm point-to-point transmission service, for periods as short as one month, to any "eligible utility" as defined therein. The Commission accepted the proposed tariff for filing, suspended its effectiveness and made it subject to refund, summarily disposed of certain matters, and set for hearing the justness and

1/ American Electric Power Service Corporation, 80 FERC ¶ 63,006 (1997).

2/ AEPSC filed the application on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company (collectively "AEP"). AEPSC is a service subsidiary of AEP.

reasonableness of the proposed rates. 3/ Requests for rehearing and clarification were filed by the AEP companies and others. 4/

In its rehearing order, the Commission announced a new "comparability" standard pertaining to open access transmission tariffs. Namely,

> an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system. [67 FERC at 61,490.]

The Commission also ordered that an evidentiary hearing be held on whether the proposed tariff was unduly discriminatory and/or anticompetitive (i.e., regarding AEP's uses of its system, any impediments or consequences of offering comparable service to others, and the costs incurred by AEP in using its transmission system). Id. at 61,490-91.

Before hearings were held, on March 29, 1995, we issued a Notice of Proposed Rulemaking in our open access rulemaking proceeding ("Open Access NOPR") in which we proposed to require all public utilities owning facilities for the transmission of electric energy in interstate commerce to file open-access transmission tariffs. 5/ Attached to the Open Access NOPR were two pro-forma tariffs that set forth the non-price terms and conditions of open access point-to-point and network transmission service. We also issued a pair of orders providing guidance on the disposition of this docket and other pending transmission

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3/ American Electric Power Service Corporation, 64 FERC ¶ 61,279 (1993), order on reh'g and clarification, 67 FERC ¶ 61,168 (1994).

4/ Requests for rehearing or clarification were filed by AEP, Industrial Energy Users-Ohio, American Municipal Power-Ohio Inc. (AMP-Ohio) jointly with Indiana Municipal Power Agency (IMPA), Blue Ridge Power Agency (Blue Ridge), Wabash Valley Power Association, Inc. (WVPA), West Virginia Power Division of UtiliCorp United Inc. (West Virginia Power), and D.C. Tie, Inc. (DC Tie).

5/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514 (1995).

tariff proceedings. 6/ In the Supplemental Guidance Order, public utilities such as AEP, which then were litigating the terms and conditions of comparability, were given the option of revising their tariffs to be consistent with the pro forma tariffs. Upon notice of the filing of such tariffs, the existing proceedings in the pending rate cases were to be held in abeyance awaiting a determination by the Commission of whether there were any genuine issues of material fact warranting further hearing procedures.

The parties in this proceeding held settlement discussions that resulted in a partial settlement that the judge certified to the Commission as a partially contested settlement. AEP's proposal to adopt the non-price terms and conditions of the pro forma tariffs was certified as uncontested. 7/ On February 14, 1996, the Commission issued an order on the partially contested settlement in which we approved AEP's proposal to adopt the non-price terms and conditions of the pro forma tariff, with certain minor modifications proposed by an intervenor and not disputed by AEP. 8/ The Commission also approved the remainder of the settlement (i.e., the pricing aspects) with respect to the participants that did not oppose the settlement. With respect to the remaining participants, the Commission remanded the contested issues to the judge for further proceedings, as deemed necessary, and for preparation of the Initial Decision. 9/

6/ American Electric Power Service Corporation, et al., 70 FERC ¶ 61,358 (1995) ("Guidance Order"), order on reh'g and clarification, 71 FERC ¶ 61,393 (1995) ("Supplemental Guidance Order"). In the Supplemental Guidance Order, the Commission provided for abbreviated filing requirements, less case-by-case litigation, and an expedited approval process for utilities such as AEP, that had voluntarily filed non-discriminatory open access transmission tariffs.

7/ The Open Access NOPR proposed "pro forma tariffs." Order No. 888, issued on April 24, 1996, see note 10 infra, adopted a single pro forma tariff. The AEP partial settlement references "pro forma tariffs" because it predates issuance of Order No. 888.

8/ American Electric Power Service Corporation, 74 FERC ¶ 61,132 (1996).

9/ Id. The order identified the remaining participants as AMP-Ohio, IMPA, Blue Ridge, the Cities of Cleveland and Hamilton, Ohio (Cleveland and Hamilton), the Indiana Office of Utility Consumer Counselor (IUCC), DC Tie, Electric Clearinghouse, Inc. (Electric Clearinghouse), WVPA, and West Virginia Power (collectively, intervenors).

While these proceedings were pending, the Commission issued Order No. 888. 10/ In response to Order No. 888, AEP submitted a revised open access transmission tariff 11/ that superseded the instant tariffs, but which used the same transmission and ancillary service rates at issue in this proceeding.

In response to the Commission's directive in its order on the partial settlement, the judge established additional procedures leading to a "paper hearing" on the remaining issues. The additional procedures included additional discovery, the filing of additional testimony by trial staff, intervenors, and AEP, the filing of a revised Joint Statement of Issues, and the filing of briefs before the judge and the Commission.

III. **DISCUSSION**

A complete list of the litigated issues was presented in the Joint Statement of Issues, and are listed in the Initial Decision. 80 FERC at 65,045-46. In the discussion below, we will focus on the contested issues and those where we reverse the findings in the Initial Decision. 12/

We summarily affirm the Initial Decision on the following issues: (1) credits for customer-owned facilities; 13/ (2) the "long generator leads" and "generator outlet lines" used for AEP

10/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

11/ On July 31, 1997, the Commission accepted the compliance filing for filing, effective July 9, 1996, subject to revision to reflect the outcome of the instant proceeding. Allegheny Power Systems, Inc., et al., 80 FERC ¶ 61,143 at 61,557 (1997).

12/ Our listing of the issues (in the table of contents) generally conforms with the issues identified by the judge in the Initial Decision.

13/ No party filed exceptions to the judge's finding that this issue is beyond the scope of this proceeding. 80 FERC at 65,054.

generation; 14/ (3) the depreciation and non-income tax components of the carrying charge; 15/ (4) the revenue credit flow through; 16/ (5) the Indianapolis Power and Light Sale; 17/ (6) the system sales and buy-sell transactions; 18/ (7) the one mill adder; 19/ (9) Reactive Supply and Voltage Control (VAr) - Refunctionalization of transmission investment; 20/ (10) VAr - Generator and Exciter Systems Costs; 21/ (11) VAr - Accessory Electric Equipment Costs; 22/ (12) VAr - Other Power Production

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14/ The judge stated that the issue of credits should be addressed when a customer requests service. 80 FERC at 65,057. The judge also noted that the Commission determined that the Rockport lines serve a transmission function and should be functionalized to transmission. See id. citing American Electric Power Service Corp., 37 FERC ¶ 63,032 (1987), aff'd in pertinent part, 44 FERC ¶ 61,206 (1988).

15/ This issue is moot because we affirm the judge's use of a net plant methodology.

16/ We deny an intervenor's request to note or take official notice of the figures found in AEP's Account No. 456 as reported in AEP's FERC Form No. 1 because they do not fall within the test period.

17/ The Indianapolis P&L sale began after, and was thus not counted in, AEP's single system peak, therefore, the judge did not include this sale in the 1 CP demand divisor. Instead, the judge adopted a revenue credit proposal.

18/ No party filed exceptions to the judge's finding adopting AIW's proposal to use 8,760 hours to develop the hourly unit rate. 80 FERC at 65,062.

19/ No party filed exceptions to the judge's finding rejecting the one-mill adder. Id. at 65,070.

20/ The judge found that AEP does not have to refunctionalize its transmission investment because Order No. 888 established "Reactive Supply and Voltage Control from Generation Sources" as one of the six ancillary services.

21/ The judge found that 24 percent of the investment in turbogenerators represents generators and exciter system costs.

22/ Examples of accessory electric equipment are: control cables, power cables, switching equipment, and station grounding. The judge approved AEP's figure of 10 percent for accessory electric equipment, which are treated in 16
(continued...)

Investment; 23/ (13) VAr - jointly-owned units; 24/ (14) Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response) - CCD Units; 25/ and (15) Energy Imbalances - Charges for Over-Scheduled Power. 26/ We find that the Initial Decision properly decided these issues and the arguments on exceptions have failed to persuade us that the Initial Decision erred or that additional discussion is necessary.

A. TRANSMISSION RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

The issue here is the same as that previously addressed by the Commission in Kentucky Utilities Company, Opinion No. 432, 85 FERC ¶ 61,274 at 62,100-05 (1998) (KU), i.e., whether a levelized or non-levelized rate design is appropriate for developing the companies' rates for unbundled transmission service.

The non-levelized method generally will recover higher costs in the early years of a facility's life and increasingly lower costs in later years. By contrast, the levelized gross plant method will recover costs in equal (or levelized) increments each year of a facility's life.

22/ (...continued) separate sub-accounts.

23/ No party filed exceptions to the judge's finding that 0.15 percent is an appropriate allocation factor for other power production investment.

24/ The judge determined that jointly-owned units are appropriately included in the costs used to determine the VAr charge. The jointly-owned generating units here at issue are owned by Columbus Southern Power Company (an AEP affiliate), along with Cincinnati Gas & Electric Company and Dayton Power & Light Company (collectively, the "CCD" units). See 80 FERC at 65,080.

25/ The judge ruled that "CCD" units are appropriately included in the costs used to determine the spinning reserve charge.

26/ The judge determined that AEP should pay 90 percent of its decremental costs for overscheduled energy outside the bandwidth.

Positions of the Parties

AEP proposed a rate for its transmission service based on the levelized gross plant approach described above. AEP argued that it has used this approach consistently for decades. 27/ AEP further asserted that it did not propose to switch the rate design methodology for any customers other than a subset of existing and potential transmission customers (i.e., requirements customers).

WVPA, IUCC, Blue Ridge, AMP-Ohio, and trial staff argued against AEP's proposed levelized gross plant approach because:

(1) under AEP's transmission tariff, transmission customers will not be charged rates that are comparable to AEP's own use of its transmission system, and the rates therefore will discriminate against transmission customers in violation of the Commission's comparability standard;

(2) factors that supported the use of the levelized gross plant approach in cases where it was adopted are absent here; 28/ and

(3) given that AEP's system is composed of facilities with varying levels of depreciation, and the levelized gross plant method does not adjust for such depreciation, the levelized gross plant approach would produce excessive revenues for AEP.

Initial Decision

The judge found that AEP's proposed levelized gross plant methodology of calculating transmission rates results in a switch from the non-levelized net plant methodology for its requirements customers, as well as its retail customers. The judge found that, as a result of this switch,

> AEP's requirements customers (as well as retail customers who may switch to transmission service) will be paying depreciation a second time leading to an overrecovery of AEP's costs. [80 FERC at 65,052.]

27/ AEP asserts that, historically, many of its interchange service rates were developed based on the levelized gross plant approach. See Ex. A-101.

28/ For example, in Southern California Edison Company, Opinion No. 341, 50 FERC ¶ 61,138 at 61,412 (1990) (SoCal Edison), and Jersey Central Power & Light Company, et al., 38 FERC ¶ 61,275 at 61,927 (1987) (Jersey Central), the company historically had used the levelized approach.

The judge also found that AEP did not demonstrate that its proposal meets the Commission's comparability standard as set forth in the Commission's Transmission Pricing Policy Statement. 29/ In this regard, the judge explained that AEP uses a non-levelized net plant approach for its native load customers while proposing a levelized gross plant approach for non-native load customers. He concluded that,

> [b]ecause AEP's open access tariff does not offer third parties access on the same or comparable basis [as AEP's use of its system], AEP's levelized approach violates the Commission's comparability standard. [80 FERC at 65,053.]

Moreover, the judge found that Commission precedent does not support AEP's proposal to use the levelized gross plant method for transmission service. In particular, the judge noted that AEP's citations to SoCal Edison and Jersey Central are inapposite because the circumstances in those cases are distinguishable from those present here, where AEP is proposing to switch depreciation methods after nearly one-third of AEP's transmission system already has been depreciated without making adjustments to prevent overrecoveries. The judge found the non-levelized net plant methodology appropriate to design rates for AEP's wholesale transmission service.

Exceptions

AEP filed an exception to the judge's rejection of its proposed levelized gross plant transmission rate design. AEP claims that the judge erred in failing to recognize that: (1) the Commission has previously found that the gross plant and net plant methods recover identical costs over the lives of the assets, and the rate differences between the two methods is simply the result of a timing difference in cost recovery; (2) AEP was not proposing a "change" in its rate design method; (3) AEP's use of the levelized method will not result in an overrecovery of its revenue requirement; and (4) comparability does not require use of the net plant methodology.

Blue Ridge, AI, WVPA, and trial staff filed briefs opposing AEP's exception on this issue.

29/ Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, FERC Stats. & Regs. ¶ 31,005 at 31,141-44 (1994), order on reconsideration, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

Discussion

We deny AEP's exception, and affirm the judge's rejection of AEP's proposed switch to a levelized gross plant rate design. While reasonable results can be produced using either levelized or non-levelized rate methods, depending on the circumstances, see, e.g., KU, 85 FERC at 62,103-05, here we find that, based on the record before us and the circumstances presented in this case, the use of a levelized gross plant rate design by AEP would not produce a just and reasonable result. Specifically, we note that AIW and trial staff witnesses testified that this switch would result in an overrecovery of costs by allowing AEP to recover anew depreciation expense that it has already recovered. See, e.g., Exs. AIW-11 at 24-31; AIW-17; S-71 through S-84. 30/ We are not convinced by AEP's opposing arguments on this issue (e.g., AEP did not provide any studies demonstrating that there would not be higher rates if the levelized method is adopted, and AEP did not substantiate its claims that it will be adding new transmission plant in the future). See Exs. A-53 at 4 and A-100 at 7.

AEP relies on our order in SoCal Edison in support of its use of a levelized gross plant rate design because AEP has historically provided under certain circumstances long-term stand-alone transmission service under levelized rates, a circumstance that AEP states persuaded the Commission to allow requirements customers to be switched to a levelized rate in SoCal Edison. We reject AEP's argument. As we explained in Consumers Energy Company, 85 FERC ¶ 61,100 at 61,366-67 (1998) (Consumers Energy), the approach we took in SoCal Edison is no longer appropriate. We believe that the concerns that led to our decisions in Consumers Energy, and also in KU, 85 FERC at 62,104-05, dictate that we no longer follow SoCal Edison.

As we found in KU, and restated in Allegheny Power Service Corp., 85 FERC ¶ 61,275 at 62,117 (1998) (APS), where a utility proposes to switch from a non-levelized net plant rate design method, "[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method." 85 FERC at 62,103-05. Just as in KU and APS, AEP has not persuaded us here that the switch in current bundled requirements service is appropriate in the circumstances of this case because: (1) AEP's system is composed of facilities with varying levels of depreciation and

30/ AIW and trial staff claimed that AEP's proposed switch in methods would increase the transmission revenue requirement by $44.5 and $61.2 million, respectively. See Joint Statement of Issues at 3; and Exs. S-72 and S-74.

(2) AEP's proposed levelized gross plant method does not account for such variations. 31/

Based on the foregoing, we reject AEP's proposal to develop its transmission tariff rate using a levelized gross plant method, and we will require AEP to recalculate its tariff rates based on a non-levelized net plant method.

As we stated in Consumers Energy, 85 FERC at 61,367, "[i]t is not our intention to prohibit the use of the levelized approach in every instance. As noted at the outset, the Commission believes that a levelized methodology may produce just and reasonable rates under different circumstances." Here, AEP has not persuaded us that its proposed change in approach is appropriate in the circumstances of this case.

2. **Definition of Investment Base**

a. Transmission/Subtransmission "Distribution Use Facilities" Exclusions

Positions of the Parties

AEP asserted that its transmission system is operated on a fully-integrated basis and therefore it included in rate base all of its facilities classified as transmission. A secondary issue involves customer-owned facilities, and AEP did not give a credit for any customer-owned facilities.

AIW 32/ opposed this treatment, arguing that customer-owned facilities with comparable functions to AEP's facilities should be considered part of the grid, and that customers with such comparable facilities should receive credits for their own facilities that function in the same manner as AEP's facilities to integrate loads and resources. AIW claimed that AEP's proposal misdefines the transmission grid for purposes of recognizing which facilities will be deemed part of the

31/ The judge's third reason (that AEP's proposed transmission tariff does not offer third parties access to its transmission system on a comparable basis to AEP's use of its own system) is no longer applicable.

32/ Earlier in this proceeding, joint testimony was presented by AMP-Ohio, IMPA, and WVPA. The judge referred to them collectively as "AIW." 80 FERC at 65,048. The judge, in the Initial Decision uses this same abbreviation to refer to AMP-Ohio and IMPA. To clarify when WVPA is not being referred to, we will refer to AMP-Ohio and IMPA together as "AI" and will use "AIW" when referring collectively to AMP-Ohio, IMPA, and WVPA.

transmission grid, and for purposes of establishing a rate for the use of the transmission owners' facilities. AIW argued that the Commission must define the grid in one of two ways, and that under either definition AEP's approach here must be rejected. First, AIW asserted that the Commission could define the grid broadly to include all facilities that are actually used to provide service under AEP's tariff. 33/ Alternatively, AIW stated that the Commission could adopt a narrow definition of the grid that encompasses only the backbone transmission facilities that are necessary to carry any party's power from a delivery point to a receipt point on bulk transmission facilities. AIW contended that if this definition is adopted, some facilities that AEP includes in its rate base should be removed.

AEP and trial staff argued that the costs of all transmission facilities in both the network and point-to-point tariff should be "rolled-in" in developing the tariff rates. 34/ AEP and trial staff contended that AIW is attempting to insert its claims for a credit for customer-owned facilities into the issue of what is AEP's appropriate rate base for transmission. AEP and trial staff asserted that the issue of what facilities AEP should include in its rate base is different from the issue of what customer facilities are entitled to a credit. Both AEP and trial staff supported the rolled-in approach and argued that the question of credits for customer-owned facilities should not be addressed in this proceeding.

Initial Decision

The judge found that AIW's comparability and other arguments "should be appropriately advanced in a different proceeding." 80 FERC at 65,055. He also rejected arguments by AIW that certain AEP facilities should be eliminated from transmission rate base because they do not serve a network function. Based on these findings, the judge concluded that AEP's rolled-in approach should be adopted.

33/ AIW contended that this definition of the grid would better serve the goal of creating workable competitive power supply markets by eliminating discriminatory transmission pricing and encouraging all transmission owners to participate in regional transmission grids.

34/ Rolled-in transmission rates are based on the costs of the entire transmission system and reflect the fact that, when there is an integrated system, all of the facilities in the system are deemed to contribute to each use of the system.

Exceptions

AI argued on exceptions that, under Order Nos. 888 and 888-A, the standard for inclusion of transmission facilities in rate base is the same standard as for inclusion of customer-owned facilities. AI Brief on Exceptions at 10. That is,

> the Transmission Provider must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. [Id. at 9.]

AI claims that the Initial Decision failed to comply with this standard because it failed to explicitly identify what AEP transmission facilities are providing transmission service to its power and transmission customers and it failed to identify what customer-owned facilities are eligible for credits.

AI further argues that the Commission should provide an "advisory opinion" on the issue of credits for customer-owned facilities. AI Brief on Exceptions at 23-36.

With regard to AI's first point, while AEP agrees that any facilities that are not used and useful in providing transmission service should be excluded from rate base, it maintains that all of the facilities included in its rate base meet that test and are thus properly includable. AEP Brief Opposing Exceptions at 7-8.

Regarding AI's second point, AEP argues that the judge correctly found that this issue is not properly before the Commission in this case. AEP contends that this is confirmed by explicit language in Order No. 888, where the Commission stated that "cost credits related to customer-owned facilities . . . are more appropriately addressed on a case-by-case basis where individual claims for credits may be evaluated against a specific set of facts." Id. at 5, citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743. AEP and trial staff contend that the Commission does not have before it any specific claim for credits for customer-owned facilities and therefore cannot evaluate such a request.

Trial staff also argues that the judge correctly found that the issue of customer credits should be treated when a service agreement is negotiated, and that this issue is beyond the scope of this proceeding.

Discussion

We affirm the judge's finding on this issue with regard to AI's first point. In Kentucky Power Company and Ohio Power Company, 64 FERC ¶ 61,112 at 61,923 (1993) (Kentucky & Ohio), we stated, "[u]nder our pricing policy, it is proper for AEP companies to develop their rates on the basis of a rolled-in, system average for all grid facilities they use for transmission, not just the lines that are at delivery voltage." Accordingly, we agree with AEP's rolled-in approach to rate base and we reject AI's contention that these facilities must be more explicitly identified.

As to AI's second point, its arguments here are the same as those raised to the judge by AIW regarding its eligibility for credits for customer-owned facilities, and we do not find these claims persuasive. As we stated in Order Nos. 888 and 888-A, and in other recent orders, the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis. 35/ As noted by AEP and trial staff, AI identified customer-owned facilities in this proceeding, but did not offer any support to justify a credit for such facilities. Thus, we affirm the judge's findings to accept AEP's rate base without any adjustment for customer credits.

b. Accumulated Deferred Income Taxes - Rockport 2 Plant Sale/Leaseback

Background information explaining this issue was presented in the Initial Decision, where the judge stated that:

> AEP's Rockport 2 plant was sold in 1989 for $1.7 billion and leased back for an initial term of 33 years. The gain from the sale of the plant was deferred and is being amortized, with the related taxes, over the term of the lease. AEP functionalized Accumulated Deferred Income Taxes (ADIT) based on a gross plant allocator. AEP took all of its company-wide ADIT and assigned a portion of them to the transmission function based on a fraction with plant in service related to transmission in the numerator and total plant in service in the denominator. ADIT is used to reduce the investment base for purposes of setting a transmission rate. [80 FERC at 65,055, footnote omitted.]

Positions of the Parties

AIW asserted that it is inequitable and contrary to Commission precedent to include in transmission rate base those costs related to the ADIT associated with the Rockport 2 plant

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35/ See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743; Order No. 888-A, FERC Stats. & Regs. ¶ 31,049 at 30,271; and Allegheny Power Systems, 80 FERC ¶ 61,143 at 61,539 (1997).

sale/leaseback (Account No. 190), 36/ but not credit transmission customers with any offsetting gains related to that same sale/leaseback. 37/ Consequently, AIW proposed adjusting the functionalization of ADIT to remove ADIT relating to the Rockport 2 plant sale/leaseback. AIW claimed that the Commission previously addressed the proper ratemaking treatment of the costs and gains associated with the Rockport 2 plant sale/leaseback in Blue Ridge, where the Commission held that "ratepayers . . . are entitled to . . . the entire benefit of the sale/leaseback." 57 FERC at 61,373.

AEP's witness stated that AIW's proposed adjustment is a piecemeal approach and that, if ADIT was uniformly removed from all transmission plant, this would increase transmission plant in rate base by more than $33 million. AEP is quite willing to make this adjustment.

Trial staff agreed with AEP that AIW's proposal should be rejected because it is piecemeal. Trial staff claimed that AIW chose one item (the Rockport 2 plant sale/leaseback) and directly assigned that item to generation, and then used the plant ratio fraction for everything else. Trial staff asserts that this approach is selective and unfair. Trial staff supports AEP's original calculation.

Initial Decision

The judge found that, notwithstanding AIW's arguments to the contrary, Blue Ridge is inapposite here. In Blue Ridge, the Commission held that ratepayers are entitled to the gain from the Rockport sale/leaseback and that the shareholders are not. The issue in that proceeding did not involve ADITs. Conversely, in this proceeding, the issue is the allocation of ADITs among groups of ratepayers. Thus, the judge found that Blue Ridge does not support AIW's position. 80 FERC at 65,055.

Exceptions

AI filed exceptions to the Initial Decision where it raised arguments similar to those raised by AIW before the judge.

36/ Account No. 190 is a rate base addition; thus, by reducing the costs from this account that are included in rate base, the transmission customers' rates will be lowered. See Exs. AIW-1 at 16-17 and AIW-4.

37/ See AI Brief on Exceptions at 36-39, citing Blue Ridge Power Agency, et al. v. Appalachian Power Company, 57 FERC ¶ 61,100 at 61,373 (1991) (Blue Ridge).

AEP and trial staff opposed AI's exception and asserted similar arguments to those they had advanced before the judge.

Discussion

We agree with the judge that AI's reliance on Blue Ridge is misplaced here. In Blue Ridge, we addressed whether ratepayers or shareholders should receive the gain on the Rockport 2 sale/leaseback, 57 FERC at 61,373, while here the issue concerns the proper allocation of ADITs between different groups of ratepayers (i.e., transmission vs. requirements customers). We find that AI is proposing a piecemeal approach that improperly focuses on a change to only one component of ADIT. AI has failed to sponsor an alternative allocation method for ADITs. Thus, we deny AI's exception and affirm the Initial Decision.

c. Generator Step-Up (GSU) Transformers

A GSU transformer is an electrical device that transforms power from a lower voltage to a higher voltage. The GSU transformers in question in this proceeding are those which step-up voltages at the generation level to higher voltages at the transmission level.

Positions of the Parties

AEP maintained that GSUs should be included in transmission rates because they perform a transmission function. AEP also argued that the inclusion of GSUs in transmission rate base is supported by Commission precedent. 38/

AI, WVPA, Blue Ridge, and trial staff argued that part of the function of GSUs is production-related and that AEP should not charge its transmission-only customers production-related costs. These participants also argued that Commission decisions supporting inclusion of GSUs in transmission rate base pre-date Order No. 888 where the Commission required utilities to offer unbundled open access transmission service. Thus, these participants argued that the cost of GSUs should be excluded from AEP's transmission rates.

Initial Decision

The judge approved AEP's proposal to continue recovering the costs of its GSUs through its transmission tariff rates. The judge found (80 FERC at 65,056-57) that this proposal was supported by Commission precedent that provides that the purpose of these facilities is to transform, or step-up, generation for

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38/ AEP cited Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 at 61,352 (1988).

the purpose of transmitting power "in bulk with less loss and at less cost . . . ." 39/ While acknowledging that the precedent he relied on was from the "pre-unbundling" era, the judge nevertheless found it to be on point because, as in the instant case, it involved transmission-only service. The judge further found that trial staff and intervenors failed to counter AEP's assertion that its classification is in accord with the Uniform System of Accounts. 80 FERC at 65,057.

Exceptions

AI, Blue Ridge, WVPA, and trial staff filed exceptions to the Initial Decision raising arguments similar to those they raised at hearing.

AEP opposed each of these exceptions.

Discussion

In the past, the Commission functionalized a utility's entire cost of GSU transformers as transmission-related and allowed the utility to recover these costs through its rolled-in transmission rate. However, in KU we decided to reverse our policy in light of the Commission's unbundling of transmission and wholesale generation services in Order No. 888. As we stated in KU, given our actions in Order No. 888,

> we believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their appropriate share of the cost of services which they use. [85 FERC at 62,111.]

Our reexamination of GSU costs in KU persuaded us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates. Those same findings are applicable here. We therefore reverse the Initial Decision to reflect our revised policy on the recovery of GSU costs, as more fully articulated in KU.

3. **Return on Equity**

After the paper hearing, the parties to this proceeding filed a Stipulation and Agreement (Stipulation) resolving the

39/ The judge cited Minnesota Power & Light Company, Opinion No. 12, 3 FERC ¶ 61,045 at 61,137 (1978), among other cases, for this proposition.

overall rate of return. 40/ Ex. Jt-3. The parties agreed that the overall rate of return to be used to calculate transmission rates in this proceeding would be 9.33 percent. Id. The judge did not rule on this issue; he neither accepted nor rejected the Stipulation. We accept the stipulated rate of return for the following reasons: (1) it does not exceed the upper bound of the ranges of reasonableness advocated by AEP and trial staff; (2) our analysis indicates that the stipulated rate of return is sufficient to assure confidence in the financial integrity of the company, to allow AEP to attract capital, and to provide investors with an adequate return; and (3) no party filed exceptions to it. Thus, we find that the stipulated overall rate of return is just and reasonable. 41/

4. Revenue Credits v. Demand Divisor Increase

There are two basic "off-system" ratemaking treatments: cost allocation and revenue credit. Cost allocation treats the transaction as part of the system load, with a portion of the system costs allocated to the off-system sale. Under this method, the demand divisor is increased to include the off-system transaction. Revenue crediting does not allocate costs to the off-system sale. Rather, on-system customers receive a credit for the revenues associated with the off-system sales. Thus, the off-system sale is not included in the demand divisor.

Positions of the Parties

As noted by the judge, "[t]his issue concerns whether AEP should increase its non-firm rate divisor to reflect full transmission system capability, which would make revenue crediting for non-firm rates unnecessary." 80 FERC at 65,060.

AEP advocated reflecting the demand of multi-year point-to-point transmission service in the demand divisor, while crediting other transmission revenues against its cost-of-service. Specifically, AEP proposes credits to the cost-of-service for revenues from transmission of electricity by others, interruptible service revenues and system sales revenues related to the transmission function.

40/ The signatories of the stipulation are AEP, AMP-Ohio, IMPA, Blue Ridge, WVPA, Indiana Office of Utility Consumer Counselor, and trial staff.

41/ See Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923); FPC v. Hope Natural Gas Company, 320 U.S. 591, 605 (1944).

AIW opposed revenue crediting, and instead argued that, with respect to non-firm rates, the appropriate cost divisor is transmission system capability as measured by AEP's generating capacity plus firm, long-term transactions. AIW asserted that the use of revenue credits to offset the non-firm revenue requirement is inappropriate because revenues from the use of excess capacity of the transmission system are already accounted for in the demand divisor.

Trial staff opposed both the AEP and AIW approaches, and argued that AEP should include all firm transmission service demand in the demand divisor, and credit only revenues from non-firm transmission service against the cost of service, as this would be consistent with Commission's precedent. Specifically, trial staff contended that its approach is consistent with Order No. 888 wherein the Commission stated that it would allow point-to-point firm transmission rates to be based on adjusted monthly system peak loads, which it defined as:

> the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with <u>all</u> firm point-to-point service customers plus the monthly contract demand reservations for <u>all</u> firm point-to-point service. [<u>42</u>/]

<u>Initial Decision</u>

The judge found that trial staff's proposed method was supported by the provisions of Order No. 888. He therefore adopted trial staff's proposal stating that:

> a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes. [<u>43</u>/]

<u>Exceptions</u>

AI filed exceptions to the judge's findings, arguing that the judge failed to address its proposal that the denominator for this service should be set at an amount equal to "AEP's generating capacity plus firm contract demands." AI Brief on Exceptions at 53. In essence, AI contends that: (1) the Commission recognizes that most non-firm service is less valuable

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<u>42</u>/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

<u>43</u>/ 80 FERC at 65,061, <u>citing</u> Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

and should be priced below the level of firm service; and (2) this should be accomplished through the use of a larger divisor, and therefore a lower rate.

AEP and trial staff oppose AI's exception. Trial staff agrees with AI's first contention, but not the second. Trial staff states that where the non-firm rate is a ceiling, or "up-to" rate capped at the firm rate (as here), the Commission has consistently allowed this treatment. Trial staff contends that the use of the same divisor for both non-firm and firm services and capping the non-firm rate at the firm rate is consistent with Commission precedent, the Commission's Pricing Policy Statement, and Order No. 888. 44/

Discussion

We reject AI's argument that the Initial Decision did not squarely address its proposal. As noted by the judge, we resolved this issue in Order No. 888, where we concluded that it is appropriate for non-firm service to be priced using up-to rates with the ceiling rate set at the firm service rate. 45/ In addition, we agree with trial staff that AEP should include the demand for all firm transmission service in the demand divisor, and only credit revenues from non-firm transmission against the cost of service. Thus, we conclude that AI's exceptions raise no arguments not already considered and rejected by the judge, and we affirm the findings of the judge on this issue.

5. **Demand Divisor**

This issue involves the development of the demand divisor for firm transmission rates.

Background

Initially, AEP proposed a non-customer-specific firm point-to-point transmission rate based on a 12 CP demand divisor. 46/

44/ Trial Staff Brief Opposing Exceptions at 58-60, citing, e.g., Central Maine Power Company, 54 FERC ¶ 61,206 at 61,612 (1991); Transmission Pricing Policy, FERC Stats. & Regs. ¶ 31,005 at 31,137 (1994); and Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

45/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

46/ 64 FERC at 62,977. Demand allocation determines the charge allocated to a class of customers. Under the 12-month coincident peak method, commonly known as the 12 CP method, demand is allocated by taking the hour of highest usage (the (continued...)

In our order setting AEP's filing for hearing, we summarily rejected AEP's proposal, citing our precedent in Southern Company Services, 61 FERC ¶ 61,339 (1992) (Southern). We gave AEP the option of developing a "customer-specific" rate by allocating AEP's total transmission-related revenue requirement using a customer-specific revenue requirement using those customers' 12 coincident peaks and billing determinants, or to develop a non-customer-specific rate using a 1 CP demand divisor. AEP elected to maintain its non-customer specific approach, but nonetheless filed a request for rehearing, asking us to allow it to use a 12 CP demand divisor in conjunction with a non-customer-specific revenue requirement. We denied rehearing on this issue and directed AEP to use the annual system peak (1 CP) as the demand divisor. 67 FERC at 61,487. AEP complied with the Commission order and filed a 1 CP demand divisor. 47/ AEP did not file a petition for review of the Commission's orders.

Positions of the Parties

Notwithstanding that the issue was rejected by summary disposition and was not set for hearing, AEP attempted to preserve and litigate this issue at hearing and continued to advocate a 12 CP demand divisor throughout the proceeding. AEP argued that in Order No. 888 the Commission changed its policy with respect to the use of a 12-CP demand divisor when a tariff allows full flexibility for point-to-point service. AEP contended that its tariff (filed in connection with its offer of settlement and Order No. 888) allows this full flexibility, and the use of a 12 CP demand divisor is thus appropriate. AEP Initial Brief at 26-27.

Initially, trial staff supported AEP's request to use a 12 CP allocator based largely on the reasons given by AEP. Trial staff argued that Commission precedent supports the use of a 12 CP divisor when the average of the 12 monthly peaks to the single peak is more than 84 percent of the single system peak. Trial staff asserted that this average for AEP's system is 89.9 percent. Trial Staff Initial Brief at 49.

46/ (...continued) coincident peak) in twelve consecutive months, determining the percentage of peak use by each customer class during each of the twelve months, and averaging the resulting percentages for each customer class. By contrast, the 1 CP method allocates demand among customer charges based on the annual coincident peak.

47/ AEP proposed a 1 CP demand divisor of 17,753 MW, reflecting its 1992 internal peak minus its interruptible loads and generator direct loads, plus 1,258 MW of firm contract demand. Ex. A-22.

AIW argued that the Commission's orders setting this proceeding for hearing summarily dismissed the 12 CP divisor as an issue in this proceeding. Thus, AIW asserted the adoption of a 12 CP rate at this late date would be both unfair and legally impermissible in this proceeding. Blue Ridge and WVPA also argued that the 12 CP v. 1 CP issue is no longer within the scope of this proceeding.

In addition to opposing AEP's 12 CP proposal on procedural grounds, intervenors also opposed the method AEP used to develop its 1 CP divisor. AIW argued that AEP's 1 CP calculation should be adjusted to include: (1) an additional 329 MW of demand associated with long-term transmission contracts; (2) 890 MW of generator direct loads served by AEP; 48/ and (3) the Buckeye Power Cooperative (Buckeye) load as a long-term load. 49/

Blue Ridge and WVPA argued that the peak demand used as the divisor should be 35,000 MW, which is the projection of AEP's transmission system capability. Blue Ridge and WVPA base this argument on a technical paper prepared by an AEP engineer stating that the system was designed to serve an expected load of 35,000 MW. 50/ However, if this approach is rejected in favor of using an annual system peak, then alternatively Blue Ridge advocated using AEP's 1993-94 winter peak (25,194 MW). Blue Ridge

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48/ AIW and trial staff argued that another 890 MW should be added to AEP's 1 CP demand divisor to reflect certain generator direct served loads (two specific retail loads, see AEP Brief Opposing Exceptions at 22), because the transmission facilities serving the two specific retail loads are routinely included in AEP's transmission planning and load flow studies. Exs. S-72; AIW-20; and AIW-11 at 39-43.

49/ AEP opposed including in the demand divisor firm transmission service AEP provides to Buckeye. AEP acknowledged that this is a resource/load integration type transaction, but it then argued that this transmission should not be included in the demand divisor because resource/load integration type service is not offered under its open access tariff. Ex. AEP-55. AIW argued that AEP's position is no longer valid because AEP is now offering network integration service. Therefore, AIW contended that the Buckeye loads should be included in the demand divisor. Ex. AIW-11 at 38-39. The Buckeye load is 937 MW, which AEP included as load for purposes of a 12 CP divisor.

50/ By comparison, the judge found that the single system peak during the test year was 18,598 MW (80 FERC at 65,064) and AEP's highest system peak occurred in 1993-1994, when total load reached 25,174 MW (80 FERC at 65,065).

contended that this peak represents AEP's proven transmission system capability, and is "a more credible proxy for transmission system capability than use of a test year peak exceeded in prior or subsequent years." Blue Ridge Initial Brief at 18.

Initial Decision

The judge noted that the Commission had considered the issue of 1 CP vs. 12 CP in both its hearing order and its order on rehearing in this proceeding, and that the Commission had rejected AEP's proposed use of the 12 CP method in both instances. The judge also found that, while Order No. 888 now allows utilities to use a 12 CP demand divisor in their point-to-point tariffs, it did not mandate the use of this method. Thus, the judge rejected AEP's proposed 12 CP methodology. 80 FERC at 65,066. 51/

The judge found the appropriate divisor to be 17,753 MW as calculated by AEP using a 1 CP demand divisor. The judge rejected Blue Ridge's contention that the peak should be based on the 1993-94 winter peak because the proceeding is based on 1992 test year costs.

Exceptions

While supporting the Initial Decision's adoption of a 1 CP approach, Blue Ridge filed exceptions arguing that the judge erred by relying on AEP's test-year peak figures to obtain the demand divisor and by failing to consider alternatives suggested by Blue Ridge and other interveners. In particular, Blue Ridge argues that the judge failed to consider peak loads subsequent to the test year (e.g., the 1993-94 winter peak) as a measure of system capability. Blue Ridge argues that consideration of these loads would yield a demand divisor of 25,194 MW, an amount that Blue Ridge claims represents AEP's proven transmission capability. 52/

AI and WVPA filed exceptions to the Initial Decision reiterating the arguments they made before the judge in support of their proposed 1 CP divisor.

AEP also filed exceptions to the Initial Decision and argues that the Commission is not legally precluded from using a 12 CP

51/ The judge did not dispute that AEP may propose a 12 CP methodology in future proceedings, but agreed with AIW that this would require a new section 205 filing.

52/ Blue Ridge Brief on Exceptions at 12-15. This figure is the highest monthly peak demand AEP had reached as of the date Blue Ridge filed its initial testimony.

divisor, and that the evidence AEP has submitted here supports the use of a 12 CP divisor.

Trial staff filed exceptions to the judge's method of calculating the single peak, arguing that it is inconsistent with both Order No. 888 and the methodology adopted by the judge in the Initial Decision. 53/ Trial staff further argues that the rationale underlying the 1 CP figure adopted by the judge is inconsistent with the determinations reached by the judge elsewhere in the Initial Decision. 54/ Trial Staff Brief on Exceptions at 20-24. However, trial staff supported the judge's determination that AEP should be precluded, for procedural reasons, from use of the 12 CP divisor in this proceeding. Trial Staff Brief Opposing Exceptions at 29-30.

AEP, AI, WVPA, Blue Ridge, and trial staff filed briefs opposing exceptions.

Discussion

We find AEP's efforts to preserve and litigate this issue at hearing unavailing. We therefore reject AEP's exception advocating the use of a 12 CP divisor, and we affirm the judge's adoption of a 1 CP divisor in this proceeding.

We summarily rejected AEP's 12 CP proposal in both our initial hearing order (64 FERC at 62,976-77) and in our order on rehearing (67 FERC at 61,487). 55/ By summary disposition, we made a final determination resolving this issue and removing the issue from further consideration in this proceeding. Any timely challenge to this final determination would have had to have been made in a petition for review to the U.S. Court of Appeals,

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53/ Trial staff's calculation started with AEP's monthly firm peak load, then subtracted the monthly coincident peaks associated with all firm point-to-point customers and added the monthly contract demand reservations for firm point-to-point service. This results in a 1 CP demand divisor of 19,537 MW.

54/ For example, in his ruling on the treatment of revenue credits, the judge ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

55/ The hearing order also gave AEP guidance on what cost support should be submitted in a new filing seeking the use of a 12 CP demand divisor. 64 FERC at 62,977.

seeking appeal of this determination. However, no such appeal was filed.

Moreover, to allow AEP to pursue this issue now would be unfair to Intervenors who, based on our prior orders, quite properly understood that this issue was no longer within the scope of this proceeding. 56/ Thus, regardless of any subsequent changes in Commission policy, it would be unfair and prejudicial to the other parties -- and a violation of their due process rights -- for us to consider anew the merits of AEP's 12 CP proposal at this late stage of the proceeding. 57/

While AEP correctly notes that in Order No. 888 we revised the policy we earlier had enunciated in Southern (and which we relied on in our earlier orders to dismiss AEP's 12 CP proposal), AEP fails to consider two important factors that relate to this change in policy. First, as noted by the judge, 80 FERC at 65,066, in Order No. 888 we did not give transmission providers an automatic and immediate right to develop their rates using a 12 CP divisor; rather, we stated that commencing with the ordered improvements in the tariff services we would no longer summarily reject filings on this basis but would instead allow transmission providers seeking a 12 CP divisor to make a filing with the Commission supporting such a proposal and to pursue this at hearing. 58/ Following the Commission's issuance of Order No. 888, AEP had the option of filing a new section 205 rate case, seeking Commission approval to use a 12 CP demand divisor in conjunction with non-customer-specific rates. It chose not to do so.

AEP instead chose to continue to raise this issue in the instant proceeding (based on our issuance of Order No. 888), even though Order No. 888 was issued nearly three years after the Commission's hearing order removing the 12 CP issue from this proceeding. However, as discussed above, due to the finality of our decision on this issue in this proceeding, we reject this

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56/ See AI Initial Brief at 56-57; AI Brief Opposing Exceptions at 31-33; WVPA Brief Opposing Exceptions at 15-16; and Blue Ridge Brief Opposing Exceptions at 12-14,

57/ This is true regardless of the judge's decision to receive into evidence AEP testimony in support of a 12 CP proposal. It is within the purview of the Commission, not of the judge, to define the scope of a proceeding and the Commission already had reached a determination on the 12 CP issue when it set this case for hearing before a judge.

58/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,737-38. See also Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,263.

effort. For these reasons, we reject AEP's proposal to allow it to develop its point-to-point transmission rates using a 12 CP divisor.

AEP advocated a 1 CP demand divisor of 17,753 MW, which was adopted by the judge, but, as pointed out by AIW and trial staff, this number is inconsistent with other determinations in the Initial Decision. We reject 17,753 MW as 1 CP demand divisor. Trial staff proposed a 1 CP demand divisor of 19,537 MW, which is derived by adding the following: (1) 16,495 MW - adjusted internal peak load; 59/ (2) 799 MW - for firm contract demand; (3) 1,304 MW - for firm transmission for others; (4) 890 MW - for two specific retail loads; 60/ and (5) 49 MW - for the Indianapolis P&L sale. We adopt trial staff's proposed 1 CP demand divisor with one modification. 61/ We affirmed the judge's decision to treat the Indianapolis P&L sale as a revenue credit; therefore, we modify trial staff's proposal by adopting 19,488 MW (19,537 MW minus 49 MW) as the 1 CP demand divisor.

6. Appalachian Pricing Method Issues

Appalachian pricing is a rate design method approved by the Commission for short-term service expected to be taken only during peak periods. The hourly charge is developed assuming usage of 16 hours a day, five days a week, 52 weeks a year (i.e., 4,160 hours per year) in contrast to the 8,760 total hours in a year. 62/ Under this rate design, 100 percent of the annual cost of service is equally distributed to each of the 52 weeks in a year; 100 percent of the weekly cost is equally distributed to five of the seven days in a week (Saturday and Sunday are off-peak days and are excluded); and 100 percent of the daily (weekday) cost is equally distributed to 16 of the 24 hours in a

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59/ See Exhibit A-24.

60/ Trial staff claimed that the Buckeye load of 937 MW is included in the 1,304 MW. Trial Staff Brief Opposing Exceptions at 34.

61/ We start with AEP's proposed internal peak load of 16,495 MW (item 1). We add to this trial staff's proposed adjustments for long-term firm transmission service (items 2 and 3) and 890 MW (item 4) for two specific retail loads (as argued by AIW and trial staff). We subtract 49 MW (item 5), based on our findings on the Indianapolis P&L sale.

62/ See Appalachian Power Company, 39 FERC ¶ 61,296 (1987) (Appalachian).

day (the other 8 hours are off-peak hours and are excluded). 63/ In addition, to prevent over-recovery, this rate is accompanied by a proviso that no customer can be charged more than the equivalent daily or weekly rate (e.g., charges for hourly usage are capped at the equivalent daily rate). 39 FERC at 61,964-65. The Appalachian rate design method was established on the theory that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. Id. at 61,965.

Positions of the Parties

AEP proposed to use the Appalachian method for developing its hourly and daily transmission rates for short-term transmission service. Trial staff generally supported AEP, arguing that it is appropriate for AEP to develop its on-peak hourly and daily rates using the Appalachian method, but only if it also offers off-peak service with hourly and daily rates developed using seven days for daily service and 8,760 hours for hourly service.

AIW and Blue Ridge contended that the Appalachian method should be abandoned and a pricing method that encourages economically efficient transactions should be used instead. They further contended that trial staff's approach is not sufficient because the only reasonable method for time-differentiation is to reduce the off-peak rates, not to raise the on-peak rate even further above the cost of service (which they claim would be the result of trial staff's proposal). AIW argued that AEP should use system capacity as the denominator to calculate the non-firm rate because they contended that system capacity represents a conservative measure of AEP's actual capability. In addition, an AIW witness proposed a six day divisor for daily service.

Initial Decision

The judge found trial staff's peak/off-peak proposal to be a reasonable adjustment to the Appalachian method for this proceeding. He stated:

> Staff's proposal achieves the Commission goal of recovering [costs] from those who take service at the time of the peak 4,160 hours while off-peak rates are based upon a distribution of annual costs over all 8,760 hours. [80 FERC at 65,069.]

63/ The use of a five day week, 16 hour day and 52 week year results in 4,160 peak hours in a year.

Thus, the judge reasoned, customers using short-term transmission service during off-peak hours do not constrict the system during the critical load period and should pay less than they would under the Appalachian method. Therefore, the judge found that trial staff's proposal would result in just and reasonable rates, and he adopted it. Id.

Exceptions

AI and WVPA claim that the Initial Decision is internally inconsistent because on the one hand it rejects using the Appalachian method in developing hourly rates for short-term transmission system sales and buy/sell transactions, while on the other hand it approves the Appalachian method for non-firm transmission rates. 64/ AI and WVPA argue that the Commission should find that an 8,760 hour year should be used in determining on-peak non-firm hourly rates for both revenue credits and unit rates in the Open Access Tariff. 65/ AEP and trial staff oppose AI's and WVPA's exceptions.

Discussion

The theory behind Appalachian pricing is that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. 39 FERC at 61,965. We have previously determined that Appalachian pricing is not warranted where it has not been shown that 16 hours is a good proxy for total daily usage.

We disagree with AI's and WVPA's contention that the Initial Decision is internally inconsistent because it uses the Appalachian method for non-firm transmission rates but not for certain revenue credits. AI and WVPA are referring to bundled non-firm, short-term system power sales transactions that AEP engaged in during the 1992 test year. AEP reflected a credit of $25.8 million for the transmission component of the non-firm short-term system power sales to which AI refers. These transactions occurred prior to open access. Therefore, AEP did not separately calculate a transmission component for these bundled power sales, but instead estimated a transmission revenue credit, thereby reducing the cost of service by the estimated

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64/ AI and WVPA ask us to compare the judge's finding basing credits for buy/sell and off-system sales on an 8,760 hour test year (which we affirmed summarily, see note 18 supra) to his ruling using a 4,160 hour year for determining the on-peak non-firm transmission rate (80 FERC at 65,068-69).

65/ WVPA Brief on Exceptions at 22; AI Brief on Exceptions at 58-60.

transmission credit. The Initial Decision approved the estimate as reasonable, 80 FERC at 65,062, and we affirm this finding for the reasons stated by the judge. Intervenors have not contended that AEP's proposal would result in unjust and unreasonable rates or in an overrecovery of costs. Instead, they argue it is inconsistent with other findings made in the Initial Decision. As mentioned above, we disagree. Therefore, there is no impediment to accepting AEP's proposal and rejecting the arguments of AI and WVPA.

Accordingly, we affirm the finding of the judge on this issue.

B. **ANCILLARY SERVICES RATES**

1. **Levelized Gross Plant Method v. Non-Levelized Net Plant Method**

Positions of the Parties

AEP recommended using the levelized gross plant methodology to determine rates for ancillary service. AEP explained that its reasoning for using this methodology is the same as discussed for base transmission rates. However, AEP believed that where services are available from third parties, rates should be market-based rather than cost-based. AEP Initial Brief at 32.

AIW argued that ancillary services rates should be developed using non-levelized net plant methodology.

Trial staff argued that three of the six ancillary services -- Regulation and Frequency Response Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service -- are not monopoly services because transmission customers can provide these services and put a downward pressure on the prices offered by AEP. Moreover, trial staff argued that AEP's levelized gross plant rates are "up to" rates that AEP can discount on a non-discriminatory basis. Based on this, trial staff concluded that developing rates for these three ancillary services on a levelized gross plant is not unreasonable.

Initial Decision

The judge found that the non-levelized net plant methodology for developing ancillary services rates is appropriate for the same reasons as discussed with respect to transmission rates.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative and determine that AEP's proposal to price these ancillary services using the levelized gross plant method is reasonable. We have repeatedly approved the use of the levelized gross plant method of pricing as a reasonable approach. Although in this proceeding, as in KU, we have rejected company proposals to use a levelized gross plant method to price transmission tariff rates, this was because these cases involved company proposals to switch pricing methods (from a non-levelized net plant pricing to a levelized gross plant pricing) in mid-stream for what were similar transmission services. It is this switching of methods, and not the levelized gross plant method itself, that we find has led to the development of rates that have not been shown to be just and reasonable. Conversely, here there is no switching of methods involved because these ancillary services are new services that were not previously provided as separate services. This is a key distinction that makes the KU precedent on the pricing of transmission rates inapposite here.

For these reasons, and because no party has shown that the ancillary rates produced by AEP's levelized gross plant method are otherwise unjust, unreasonable or unduly discriminatory, we adopt AEP's pricing approach.

2. **Scheduling, System Control and Dispatch Service**

We agree with the judge that there are no remaining issues involving this ancillary service. 80 FERC at 65,071. Ex. Jt-1 at 21. The per unit rates will be affected by the cost divisor ultimately found just and reasonable, which we find is the same divisor we found proper for the base transmission rate -- 19,488 MW. See section III.A.5 above.

3. **Reactive Supply and Voltage Control (VAr)**

a. Active and Reactive Allocation Factor

Positions of the Parties

AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function." AEP Initial Brief at 37. While both AEP and trial staff generally agreed on the methodology to calculate allocation factor applicable to reactive production, 66/ they disagreed on the location at which the reactive capability should be measured. Depending on the measuring point location chosen, costs will be shifted between customers taking transmission service and native load customers. AEP asserted that the name-plate reactive capability at the generator terminals should be used. 67/ Trial staff explained that some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs, before it reaches the transmission system. 68/ Accordingly, trial staff argued that the Commission should not use the generator's nameplate reactive capability, but instead should use the reactive capability at the GSU terminals available to the transmission system. Ex. S-88. Thus, while AEP proposed a reactive power allocation factor of 21 percent, trial staff recommended only 11.47 percent.

AEP, however, maintained that the GSUs should remain a part of the transmission system. Also, even if GSUs are functionalized to production, AEP argued that despite the reactive power losses associated with auxiliary loads and GSUs, the generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Reply Brief at 43.

Initial Decision

The judge found merit in AEP's argument that there must be enough reactive power remaining at the transmission terminal to provide the voltage control support on the system. Accordingly, he determined that AEP's proposed 21 percent allocation factor for reactive power measured at the generator terminals was just and reasonable. 69/

66/ The parties agreed to use the formula $MVAr^2/MVA^2$ to determine the allocation factor.

67/ AEP maintains that reactive capability should be measured at generator terminals (the low-voltage side of the GSU), while trial staff maintains that it should be measured at the GSU terminals nearest to the transmission system (the high-voltage side of the GSU).

68/ As noted earlier, trial staff argued that the GSUs should be refunctionalized to production.

69/ 80 FERC at 65,079. The judge found that the GSUs perform transmission functions. Id. He therefore did not reach trial staff's contentions that relied on the facilities (continued...)

Exceptions

Trial staff filed exceptions arguing again that, during the step up of power and energy from the generator terminal voltage to transmission voltage, some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs. In its exceptions, trial staff reiterates its position that the critical issue here is whether GSUs perform a transmission function or a generation function. Trial staff argues that the judge erroneously determined that the GSUs should be assigned to the transmission function, and that, consequently, the reactive power losses in the GSUs belong to the transmission function. However, trial staff contends that the judge's finding was erroneous. Trial staff states that, in the event the Commission reverses the judge on GSUs, it should adopt the trial staff's reactive power allocation factor of 11.47 percent. Trial Staff Brief on Exceptions at 32-33.

In its Brief Opposing Exceptions, AEP disagrees with trial staff's contention that the functionalization of GSUs to transmission or production is controlling on this issue because the allocation factor is based on capability. AEP argues that, irrespective of the location at which reactive power capability is measured, the generating equipment must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Brief Opposing Exceptions at 37-38.

Discussion

We adopt the judge's finding that 21 percent is the appropriate allocation factor to segregate the costs of reactive (VAr) production from those of active (Watt) production. We are not persuaded by trial staff's assertion that the reactive capability of the generators should be reduced by the VArs consumed by GSUs and auxiliary loads before developing an allocation factor. We agree with AEP (and the judge) that the allocation factor should be based on the capability of the generators to produce VArs and that this capability should be measured at the generator terminals. We find merit in AEP's assertion that a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission

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69/ (...continued)
being deemed to perform generation functions.

system. 70/ See AEP Reply Brief at 43. For these reasons, and for the reasons stated by the judge in the Initial Decision, we affirm the judge's ruling on this issue in the Initial Decision.

b. Unrelated O&M Expenses

Positions of the Parties

AEP proposed to include all O&M expenses that are directly and indirectly related to the production of reactive power in its carrying charge rate 71/ of 22.1 percent. AEP claimed that its methodology excludes O&M expenses unrelated to reactive power production. Exs. A-28 at 1; and A-95. Trial staff agreed. Trial Staff Reply Brief at 39.

AIW argued that AEP's method will lead to an overrecovery of its O&M expenses because in developing its carrying charge, AEP improperly included costs from O&M accounts that have no direct relation to the production of reactive power. AIW also argued that AEP's method allocates O&M expenses on a different basis than it allocates plant costs related to VAr production. In addition, AIW argued that AEP should remedy the problem by performing an account-by-account analysis of which O&M costs are actually related to the production of reactive power, and that only those costs should be included in the development of the fixed charge rate. Ex. AIW-11 at 58. AIW Initial Brief at 70-71.

AEP disagreed with AIW's argument that O&M expenses indirectly related to production equipment should be excluded from the development of the carrying charge rate because they do not directly contribute to reactive power production. AEP Initial Brief at 39-40. AEP further stated, "[t]here is no production equipment [that] does not contribute to reactive power production." Ex. A-53 at 43.

Initial Decision

The judge ruled that AIW's method of allocating O&M expenses related to reactive power production is superior to AEP's method because AIW logically assigned O&M expenses to the VAr producing equipment in the same proportion as its investment in such equipment. The judge found that AEP had not justified why O&M

70/ However, we will require AEP to recalculate the transmission loss factor to exclude real power losses that take place in GSUs.

71/ Carrying charge is a component of revenue requirements that provides for the return of and on capital invested in plant, taxes, and insurance premiums.

expenses related to VAr production should be allocated on a different basis than the plant costs related to VAr production, and he thus rejected AEP's proposal (which would have produced higher rates). The judge found AIW's approach to be reasonable because it provided for a consistent treatment of the plant costs and O&M expenses related to VAr production. The judge also found that AEP's argument (that there is no production equipment that does not contribute to reactive power production) is unavailing because the issue here does not concern the total exclusion of the O&M expenses from the VAr charge, but instead involves the proper allocation of O&M expenses to the VAr charge. However, the judge noted that in accordance with his ruling that the non-levelized net plant method is appropriate for developing ancillary services rates, the issue of allocation of O&M expenses is moot because there will be no carrying charge under the non-levelized method. 80 FERC at 65,081-82.

<u>Exceptions</u>

No party filed exceptions on this issue.

<u>Discussion</u>

In accordance with our ruling approving AEP's use of a levelized gross plant rate design for developing the ancillary services rates, the proper allocation of reactive power O&M expenses is no longer moot. We affirm the judge's finding that AIW's method of allocating reactive power O&M expenses is superior to AEP's method for the reasons stated in the Initial Decision.

4. **<u>Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response)</u>**

a. <u>Pricing for Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service</u>

<u>Positions of the Parties</u>

AEP proposed to allocate the minimum East Central Reliability Council (ECAR) requirement of a 6 percent operating reserve level as follows: 1.5 percent for Regulation and Frequency Response Service; 1.5 percent for Spinning Reserve Service; and 3 percent for Supplemental Reserve Service. AEP Initial Brief at 40-41.

While no party took issue with AEP's allocation of 3 percent for Supplemental Reserve Service, trial staff, AIW, and IUCC disagreed with AEP's method of dividing the 3 percent ECAR minimum Spinning Reserve in equal amounts between Regulation and

Frequency Response and Spinning Reserve. 72/ Noting that there are no industry guidelines available on this matter, and that AEP failed to provide data to track moment-to-moment variations (which would have enabled the parties to more accurately allocate this 3 percent figure), trial staff developed its own 4-step method based on AEP's hour-to-hour load deviations. In developing its 4-step method, trial staff made four "simplifying assumptions." 73/ Using that method, trial staff calculated 1 percent for Regulation and Frequency Response Service and 2 percent for Spinning Reserve Service. 74/ AEP opposed trial staff's proposed allocation and methodology, contending that several of the underlying assumptions made by trial staff served to understate the amount of capacity needed for regulation and frequency response service to follow load.

Initial Decision

The judge rejected AEP's criticism of trial staff's approach as conclusory and found that AEP neither provided data to track moment-to-moment variations nor any evidence to support its claim that trial staff's estimate for regulation and frequency response service was understated. The judge also noted that although AEP stated in its Initial Brief that it would discuss this issue in detail in its Reply Brief, AEP's Reply Brief does not even address operating reserves. AEP Initial Brief at 41. The judge then held that until a standard is developed and endorsed by the Commission, trial staff's formula is reliable to calculate the level of Regulation and Frequency Response Service for AEP. Thus, the judge allowed AEP to recover 1 percent of its production costs for the provision of Regulation and Frequency Response Service and 2 percent for the provision of Spinning Reserve Service.

Exceptions

AEP filed exceptions to the judge's decision and argues that trial staff's four "simplifying assumptions" are not representative of actual AEP operating conditions. AEP asserts that, in addition to a Spinning Reserve requirement of three

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72/ The parties agreed that AEP carries a total of 6 percent of capacity to provide for the following three ancillary services: (1) Regulation and Frequency Response Service, (2) Spinning Reserve Service, and (3) Supplemental Reserve Service.

73/ Trial staff's "simplifying assumptions" are described in Trial Staff's Brief Opposing Exceptions at 40.

74/ Trial Staff Initial Brief at 65. AI Initial Brief at 71. IUCC Initial Brief at 30-31.

percent, an additional three percent is required for Regulation and Frequency Response Service merely to follow the load trend (for a total of six percent). Nevertheless, AEP proposes only to recover a Regulation and Frequency Response Reserve of 1.5 percent and a Spinning Reserve of 1.5 percent (for a total of three percent). AEP Brief on Exceptions at 34.

Trial staff argues that a proper breakdown between Regulation and Frequency Response Service and Spinning Reserve Service is important because a customer has fewer options available for obtaining Regulation and Frequency Response Service. Trial staff points out that while both services can be obtained from a source other than the transmission provider, Regulation and Frequency Response Service can only be provided by generators that are operated under Automatic Generation Control or some NERC-approved method that enables the generator to instantaneously follow load, thus creating technical limitations on a purchaser's ability to obtain this service from a provider other than the transmission provider. Trial staff argues that such limitations do not exist for competitively obtaining Spinning Reserve Service. Trial Staff Brief Opposing Exceptions at 36-43.

Discussion

We reverse the judge and, based on the evidence presented in the record, approve AEP's proposal that the pricing of Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service should be allocated based on 1.5 percent, 1.5 percent, and 3.0 percent of production costs, respectively. As noted above, there were no industry guidelines for the pricing of these ancillary services at the time this case was litigated, and thus AEP attempted to allocate the ECAR minimum requirement among these services. No participant has demonstrated that AEP's proposal is unreasonable, and indeed, the fact that the different approaches used by AEP and trial staff each produces a combined rate of 3.0 percent for Regulation and Frequency Response Service and Spinning Reserve Service corroborates the reasonableness of AEP's overall end result, based on the evidence presented in the record. AEP is only required to show that its proposal is reasonable; not that its proposal is the only reasonable result on this record, or that its proposal is superior to all other proposals. 75/ For these reasons, we adopt AEP's proposal.

b. Other Production Facilities

Positions of the Parties

AEP did not seek to include GSUs in developing its ancillary services rate because it included GSUs in developing its base transmission rate. However, trial staff argued that GSUs are used in providing generation-based ancillary services to transmission customers, and therefore, the cost of GSUs should be included in the rate for those ancillary services. 76/ Trial Staff Initial Brief at 72-73. AIW opposed trial staff's proposal to include GSUs in the charges for AEP's generation-based ancillary services, arguing that these services are provided at the generation bus and do not require the use of GSUs. AI Initial Brief at 71-72. Ex. AIW-46 at 20.

Initial Decision

The judge determined that, consistent with his finding that GSUs perform a transmission function, GSU costs already are allocated to transmission customers. He held, therefore, that GSUs should not be included as a cost for any of the ancillary services.

Discussion

As discussed above, in section III.A.2.c, our reexamination of GSU costs in KU persuaded us that the costs of a GSU

75/ See City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984), cert. denied, 467 U.S. 917 (1984) (utility need establish only that its proposed rate design is reasonable, not that it is superior to all alternatives); MCI Telecommunications Inc. v. FCC, 627 F.2d 322, 340 (D.C. Cir. 1980) (the standard of "just and reasonable" does not require that the rates be perfect); New England Power Company, Opinion No. 352-A, 54 FERC ¶ 61,055 at 61,198, aff'd sub nom. Town of Norwood, Mass. v. FERC, 962 F.2d 20 (D.C. Cir. 1992) (a proposed rate design need only be shown to be just and reasonable, not superior to all alternatives).

76/ The generation-based ancillary services referred to by trial staff are: (1) Reactive Supply and Voltage Control; (2) Regulation and Frequency Response Reserve Service; (3) Operating Reserve - Spinning Reserve Service; and (4) Operating Reserve - Supplemental Reserve Service.

transformer should be directly assigned to its related generating unit, not rolled into transmission rates. In KU, we stated that:

> GSUs also perform an important function in the provision of a new category of services we identified in Order No. 888, ancillary services (e.g., Operating Reserve, Regulation and Frequency Response Service, Reactive Supply and Voltage Control). Ancillary services supplied from generation resources cannot be provided without reliance upon GSUs, regardless of where power is coming from or going to.
>
> In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using these facilities. [85 FERC at 62,112].

Therefore, we find that it is appropriate to include the cost of GSUs in developing rates for all ancillary services that are supplied from generation sources. Accordingly, we reverse the judge's finding in the Initial Decision that GSUs should not be included as a cost for any of the ancillary services, and we instead adopt trial staff's proposal to include GSU costs in ancillary services rates.

5. **Energy Imbalances**

Order No. 888-A defines Energy Imbalance Service as follows:

> Energy Imbalance Service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to make up the difference . . . by adjusting its energy deliveries to eliminate the imbalance. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus, the Final Rule established an hourly energy deviation band of +/- 1.5 percent (with a minimum of 1 MW) for energy imbalance. [77/]

77/ FERC Stats. & Regs. ¶ 31,048 at 30,229. In Order No. 888-A, the Commission clarified the definition of Energy Imbalance Service provided in Order No. 888, FERC Stats. & Regs. ¶ 31,038 at 31,960-61.

a. Deadband

Positions of the Parties

AEP offered a deviation band (also known as a "deadband") of 1.5 percent, consistent with the figure we required in Order No. 888. 78/ AIW argued that the deadband of 1.5 percent is too small and discriminates against smaller systems. AI Initial Brief at 42, AI Reply Brief at 62.

Trial staff argued that AEP complied with the Commission requirements by establishing a deadband of +/- 1.5 percent. Trial Staff Initial Brief at 73-74.

Initial Decision

The judge rejected arguments made by AIW and ruled that AEP properly included a deadband of +/- 1.5 percent, as required by Order No. 888. 80 FERC at 65,085.

Exceptions

AIW filed exceptions, generally reiterating its arguments made before the judge. 79/ In opposing AIW's exceptions on this issue, trial staff argues that changing the size of the deadband would amount to changing a term and condition of the Order No. 888 *pro forma* tariff, which is beyond the scope of this proceeding. AEP and trial staff point out that Order No. 888-A, while keeping the deadband at +/- 1.5 percent, modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW to address the concerns raised by smaller systems such as AIW.

Discussion

We affirm the judge. In Order No. 888-A, we addressed the issue of the size of the deviation band in detail. There, we held that a bandwidth of 1.5 percent promotes good scheduling practices by transmission customers and that the implementation

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78/ When the energy imbalance is within the prescribed bandwidth, the energy may be returned in kind. When the energy imbalance is outside the bandwidth, specific rates are applicable as discussed below.

79/ AI Brief on Exceptions at 71-72; WVPA Brief on Exceptions at 23-24.

of scheduled transactions should not overly burden others. 80/ Also, as noted by AEP and trial staff, in Order No. 888-A we modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW. 81/ We therefore conclude, as did the judge, that AEP's proposals on bandwidth comply with the requirements of Order Nos. 888 and 888-A. Accordingly, we affirm the judge's finding on this issue for the reasons set forth in the Initial Decision.

b. Charges for Under-Scheduled Power

Positions of the Parties

AEP argued that a transmission customer should pay a charge of 100 mills/kWh for under-scheduled energy outside the deadband. 82/ Trial staff supported this charge stating that such a charge would act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load.

AIW argued that all under-scheduled energy should be returned in kind. However, AIW asserted that a 100 mills/kWh charge may be reasonable for under-scheduled energy which exceeds the 7.5 percent (i.e., 1.5 percent for the deviation band plus 6 percent for operating reserve services) the customer purchases from AEP or supplies itself.

Initial Decision

The judge found AIW's position that all under-scheduled power be returned in kind to be inconsistent with the Order No. 888 provision that requires a separately stated charge for such under-scheduled power. The judge also found that AEP's 100 mills/kWh charge was reasonable because such a charge accounts for the fact that the imbalances occur on an hourly basis. The judge ruled that AIW's interpretation that customers that buy operating reserves from AEP are entitled to a 7.5 percent deadband is not correct, and that Order No. 888 provides for several ways in which the customer may reduce or eliminate the need for energy imbalance service, such as dynamic scheduling.

80/ See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,232-33.

81/ Id.

82/ 100 mills/kWh was the rate utilities typically charged their customers for emergency power service, and in Detroit Edison Company, Opinion No. --, 88 FERC ¶ 61,--- (1999) (Detroit Edison), we recently found that energy imbalance service is similar to emergency power service.

Exceptions

AI argues that a 100 mills/kWh charge might be reasonable if the deadband is expanded to include operating reserves. However, AI contends that since the judge did not expand the deadband to include operating reserves, the charge should be no greater than AEP's out-of-pocket costs. AI and WVPA argue that the charge for energy outside the deadband is too high and not cost-justified. AI Brief on Exceptions at 72; and WVPA Brief on Exceptions at 14, 22-24.

Discussion

As we explained above, "Energy Imbalance Service" is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over a single hour. We did not intend it to be used as a substitute for operating reserves. See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,230. Furthermore, we find that a 100 mills/kWh charge for underscheduled energy outside the deadband is reasonable because such a charge will act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load. In addition, in Detroit Edison we recently found that energy imbalance service is similar to emergency power service, and that 100 mills/kWh is the rate utilities typically have charged their customers for emergency power service. Accordingly, we affirm the judge's finding on this issue.

6. **Losses**

a. Reserve Margin

Positions of the Parties

AEP proposed a 20 percent reserve margin in calculating costs associated with capacity required to make up for losses. AEP explained that: (1) losses are similar to firm load; (2) losses cannot be controlled and are not subject to curtailment; and (3) transmission customers do not have to buy loss service from AEP and instead are free to make alternative arrangements to supply losses. AEP Initial Brief at 43; Ex. A-28.

AIW disagreed with AEP's proposal and argued that a transmission customer is required to provide spinning and supplemental operating reserves for the full amount of its load and losses under AEP's tariff Schedules 5 and 6. Therefore, AIW asserted that an obligation to pay for a separate 20 percent reserve margin is essentially a double charge.

Initial Decision

The judge ruled that although the transmission customers have alternative ways of supplying losses, a 20 percent reserve margin for losses on top of spinning and supplemental operating reserves of 6 percent would amount to double counting of reserves. Therefore, the judge determined that a 14 percent reserve margin is appropriate in this case for calculating capacity costs for losses.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative. Notwithstanding the fact that there were no exceptions filed to the judge's determination that a 14 percent reserve margin is appropriate, we find no basis for AEP's contention that any reserve margin is cost-justified for loss service. First, AEP has sponsored no studies or quantitative evidence showing that a reserve margin of any amount is cost-justified for loss service, and there is no Commission precedent supporting such a charge. Second, in Order No. 888 we neither required customers to take such a service from their transmission providers or for transmission providers to provide such a service. There is no basis for AEP to assess a charge under its open access tariff for a service that is not even offered under that tariff. Finally, we disagree with AEP's claim that losses are similar to firm load. In fact, AEP's provision of loss services is discretionary both for AEP and its customers. Thus, we find no justification for AEP's imposition of a charge for reserves for loss service.

b. Transmission Loss Factor

Positions of the Parties

AEP proposed a transmission loss factor of 3.6 percent. AIW contended that AEP's loss factor is excessive arguing that: (1) AEP did not provide any support that losses from theoretical load flow and other studies represent actual system losses; and (2) losses on AEP's local area network and distribution system (facilities below 69 KV) should be excluded from this loss factor calculation because many of AEP's transmission customers provide losses on their own local area networks and distribution system. To rebut AIW's claim that it was improper for AEP to roll-in the local area networks and distribution losses, AEP argued that its charging of losses associated with all transmission facilities used to provide service is in accordance with Commission policy favoring rolled-in pricing. 83/ Trial staff did not contest AEP's loss factor.

Initial Decision

The judge determined that AEP's loss factor of 3.6 percent is reasonable. The judge rejected AIW's claim regarding local area network and distribution use stating that AIW did not present any evidence to prove its claim, nor did it offer any evidence showing what percentage should be assigned to that portion of the losses allegedly associated with the distribution function. He held that AIW did not provide any arguments to rebut AEP's reliance on Kentucky Power. Specifically, that case affirmed a prior Commission order 84/ approving an increase in the AEP loss factor from 2.0 percent to 3.6 percent. The Commission held in Appalachian II that:

> AEP's proposal is entirely consistent with the Commission's requirements for charging customers for transmission losses. . . . Customers' service is provided by and priced on the basis of the AEP integrated transmission system . . . . [85/]

Exceptions

AI filed exceptions in which it generally reiterates the same arguments made by AIW before the judge. AI Brief on Exceptions at 72-73.

Discussion

We affirm the judge's finding, adopting a loss factor of 3.6 percent, for the reasons set forth in the Initial Decision. However, we note that the AEP study includes all facilities including GSUs. Because we have ruled that GSUs should be assigned to production, we will require AEP to recalculate the transmission loss factor to exclude real power losses attributable to GSUs.

83/ AEP cited Kentucky & Ohio in support of its claim. AEP Initial Brief at 43. In Kentucky & Ohio, the Commission specifically approved the rolled-in method with respect to losses on the AEP System. 64 FERC at 61,923.

84/ Appalachian Power Company, et al., 63 FERC ¶ 61,165 (1993) (Appalachian II).

85/ Id. at 62,149.

The Commission orders:

(A) The Initial Decision issued in this proceeding on August 7, 1997 is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) AEP is hereby directed to submit a compliance filing within 60 days of the date of issuance of this order. However, if a request for rehearing is filed, AEP shall make its compliance filing within 30 days of the date the Commission disposes of the request for rehearing.

(C) Within 30 days of acceptance of the compliance filing, AEP shall make refunds, together with interest calculated pursuant to 18 C.F.R. § 35.19a (1999). Within 15 days of the date of payment of refunds, AEP shall file a report showing the computation of refunds and interest paid. A copy of the refund report shall also be sent to the affected state commissions.

By the Commission.

(S E A L)

David P Boergers
David P. Boergers,
Secretary.

UNITED STATES OF AMERICA88 ferc • 61, 141
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 440

American Electric Power Service Corporation	)	Docket No. ER93-540-006

OPINION AND ORDER AFFIRMING IN PART AND
REVERSING IN PART INITIAL DECISION

Issued: July 30, 1999

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation) Docket No. ER93-540-006

OPINION NO. 440

APPEARANCES

Edward J. Brady, and Kevin F. Duffy, on behalf of American Electric Power Service Corporation.

James N. Horwood, Mark S. Hegedus, and John W. Bentine, on behalf of American Municipal Power-Ohio, Inc., and Indiana Municipal Power Agency.

Frederick H. Ritts, and Julie B. Greenisen on behalf of Blue Ridge Power Agency.

Don F. Morton, Charles W. Ritz, III, and James A.L. Buddenbaum, on behalf of Wabash Valley Power Association, Inc.

John J. Bartus, Warren C. Wood, Richard L. Miles, and Stan Berman, on behalf of the Federal Energy Regulatory Commission Trial Staff.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt H,bert, Jr.

American Electric Power Service Corporation) Docket No. ER93-540-006

OPINION NO. 440

OPINION AND ORDER AFFIRMING IN PART,
AND REVERSING IN PART, INITIAL DECISION

(Issued July 30, 1999)

I. INTRODUCTION

This proceeding is before the Commission on exceptions to an Initial Decision issued in this proceeding on August 7, 1997 (Initial Decision). 1/ In this order, with certain enumerated exceptions, we affirm the findings of the presiding administrative law judge (judge).

II. BACKGROUND

This proceeding began when American Electric Power Service Corporation (AEPSC) 2/ filed a transmission service and ancillary services tariff for Commission approval. The proposed tariff offered firm point-to-point transmission service, for periods as short as one month, to any "eligible utility" as defined therein. The Commission accepted the proposed tariff for filing, suspended its effectiveness and made it subject to refund, summarily disposed of certain matters, and set for hearing the justness and

1/ American Electric Power Service Corporation, 80 FERC • 63,006 (1997).

2/ AEPSC filed the application on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company (collectively "AEP"). AEPSC is a service subsidiary of AEP.

reasonableness of the proposed rates. 3/ Requests for rehearing and clarification were filed by the AEP companies and others. 4/

In its rehearing order, the Commission announced a new "comparability" standard pertaining to open access transmission tariffs. Namely,

> an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system. [67 FERC at 61,490.]

The Commission also ordered that an evidentiary hearing be held on whether the proposed tariff was unduly discriminatory and/or anticompetitive (i.e., regarding AEP's uses of its system, any impediments or consequences of offering comparable service to others, and the costs incurred by AEP in using its transmission system). Id. at 61,490-91.

Before hearings were held, on March 29, 1995, we issued a Notice of Proposed Rulemaking in our open access rulemaking proceeding ("Open Access NOPR") in which we proposed to require all public utilities owning facilities for the transmission of electric energy in interstate commerce to file open-access transmission tariffs. 5/ Attached to the Open Access NOPR were two pro-forma tariffs that set forth the non-price terms and conditions of open access point-to-point and network transmission service. We also issued a pair of orders providing guidance on the disposition of this docket and other pending transmission

3/ American Electric Power Service Corporation, 64 FERC • 61,279 (1993), order on reh'g and clarification, 67 FERC • 61,168 (1994).

4/ Requests for rehearing or clarification were filed by AEP, Industrial Energy Users-Ohio, American Municipal Power-Ohio Inc. (AMP-Ohio) jointly with Indiana Municipal Power Agency (IMPA), Blue Ridge Power Agency (Blue Ridge), Wabash Valley Power Association, Inc. (WVPA), West Virginia Power Division of UtiliCorp United Inc. (West Virginia Power), and D.C. Tie, Inc. (DC Tie).

5/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. • 32,514 (1995).

tariff proceedings. 6/ In the Supplemental Guidance Order, public utilities such as AEP, which then were litigating the terms and conditions of comparability, were given the option of revising their tariffs to be consistent with the pro forma tariffs. Upon notice of the filing of such tariffs, the existing proceedings in the pending rate cases were to be held in abeyance awaiting a determination by the Commission of whether there were any genuine issues of material fact warranting further hearing procedures.

The parties in this proceeding held settlement discussions that resulted in a partial settlement that the judge certified to the Commission as a partially contested settlement. AEP's proposal to adopt the non-price terms and conditions of the pro forma tariffs was certified as uncontested. 7/ On February 14, 1996, the Commission issued an order on the partially contested settlement in which we approved AEP's proposal to adopt the non-price terms and conditions of the pro forma tariff, with certain minor modifications proposed by an intervenor and not disputed by AEP. 8/ The Commission also approved the remainder of the settlement (i.e., the pricing aspects) with respect to the participants that did not oppose the settlement. With respect to the remaining participants, the Commission remanded the contested issues to the judge for further proceedings, as deemed necessary, and for preparation of the Initial Decision. 9/

6/ American Electric Power Service Corporation, et al., 70 FERC • 61,358 (1995) ("Guidance Order"), order on reh'g and clarification, 71 FERC • 61,393 (1995) ("Supplemental Guidance Order"). In the Supplemental Guidance Order, the Commission provided for abbreviated filing requirements, less case-by-case litigation, and an expedited approval process for utilities such as AEP, that had voluntarily filed non-discriminatory open access transmission tariffs.

7/ The Open Access NOPR proposed "pro forma tariffs." Order No. 888, issued on April 24, 1996, see note 10 infra, adopted a single pro forma tariff. The AEP partial settlement references "pro forma tariffs" because it pre-dates issuance of Order No. 888.

8/ American Electric Power Service Corporation, 74 FERC • 61,132 (1996).

9/ Id. The order identified the remaining participants as AMP-Ohio, IMPA, Blue Ridge, the Cities of Cleveland and Hamilton, Ohio (Cleveland and Hamilton), the Indiana Office of Utility Consumer Counselor (IUCC), DC Tie, Electric Clearinghouse, Inc. (Electric Clearinghouse), WVPA, and West Virginia Power (collectively, intervenors).

While these proceedings were pending, the Commission issued Order No. 888. 10/ In response to Order No. 888, AEP submitted a revised open access transmission tariff 11/ that superseded the instant tariffs, but which used the same transmission and ancillary service rates at issue in this proceeding.

In response to the Commission's directive in its order on the partial settlement, the judge established additional procedures leading to a "paper hearing" on the remaining issues. The additional procedures included additional discovery, the filing of additional testimony by trial staff, intervenors, and AEP, the filing of a revised Joint Statement of Issues, and the filing of briefs before the judge and the Commission.

III. DISCUSSION

A complete list of the litigated issues was presented in the Joint Statement of Issues, and are listed in the Initial Decision. 80 FERC at 65,045-46. In the discussion below, we will focus on the contested issues and those where we reverse the findings in the Initial Decision. 12/

We summarily affirm the Initial Decision on the following issues: (1) credits for customer-owned facilities; 13/ (2) the "long generator leads" and "generator outlet lines" used for AEP

10/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. • 31,036 (1996); order on reh g, Order No. 888-A, FERC Stats. & Regs. • 31,048 (1997), order on reh g, Order No. 888-B, 81 FERC • 61,248 (1997), order on reh g, Order No. 888-C, 82 FERC • 61,046 (1998).

11/ On July 31, 1997, the Commission accepted the compliance filing for filing, effective July 9, 1996, subject to revision to reflect the outcome of the instant proceeding. Allegheny Power Systems, Inc., et al., 80 FERC • 61,143 at 61,557 (1997).

12/ Our listing of the issues (in the table of contents) generally conforms with the issues identified by the judge in the Initial Decision.

13/ No party filed exceptions to the judge's finding that this issue is beyond the scope of this proceeding. 80 FERC at 65,054.

generation; 14/ (3) the depreciation and non-income tax components of the carrying charge; 15/ (4) the revenue credit flow through; 16/ (5) the Indianapolis Power and Light Sale; 17/ (6) the system sales and buy-sell transactions; 18/ (7) the one mill adder; 19/ (9) Reactive Supply and Voltage Control (VAr) - Refunctionalization of transmission investment; 20/ (10) VAr - Generator and Exciter Systems Costs; 21/ (11) VAr - Accessory Electric Equipment Costs; 22/ (12) VAr - Other Power Production

14/ The judge stated that the issue of credits should be addressed when a customer requests service. 80 FERC at 65,057. The judge also noted that the Commission determined that the Rockport lines serve a transmission function and should be functionalized to transmission. See id. citing American Electric Power Service Corp., 37 FERC • 63,032 (1987), aff'd in pertinent part, 44 FERC • 61,206 (1988).

15/ This issue is moot because we affirm the judge's use of a net plant methodology.

16/ We deny an intervenor's request to note or take official notice of the figures found in AEP's Account No. 456 as reported in AEP's FERC Form No. 1 because they do not fall within the test period.

17/ The Indianapolis P&L sale began after, and was thus not counted in, AEP's single system peak, therefore, the judge did not include this sale in the 1 CP demand divisor. Instead, the judge adopted a revenue credit proposal.

18/ No party filed exceptions to the judge's finding adopting AIW's proposal to use 8,760 hours to develop the hourly unit rate. 80 FERC at 65,062.

19/ No party filed exceptions to the judge's finding rejecting the one-mill adder. Id. at 65,070.

20/ The judge found that AEP does not have to refunctionalize its transmission investment because Order No. 888 established "Reactive Supply and Voltage Control from Generation Sources" as one of the six ancillary services.

21/ The judge found that 24 percent of the investment in turbogenerators represents generators and exciter system costs.

22/ Examples of accessory electric equipment are: control cables, power cables, switching equipment, and station grounding. The judge approved AEP's figure of 10 percent for accessory electric equipment, which are treated in 16
(continued...)

Investment; 23/ (13) VAr - jointly-owned units; 24/ (14) Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response) - CCD Units; 25/ and (15) Energy Imbalances - Charges for Over-Scheduled Power. 26/ We find that the Initial Decision properly decided these issues and the arguments on exceptions have failed to persuade us that the Initial Decision erred or that additional discussion is necessary.

A. TRANSMISSION RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

The issue here is the same as that previously addressed by the Commission in Kentucky Utilities Company, Opinion No. 432, 85 FERC • 61,274 at 62,100-05 (1998) (KU), i.e., whether a levelized or non-levelized rate design is appropriate for developing the companies' rates for unbundled transmission service.

The non-levelized method generally will recover higher costs in the early years of a facility's life and increasingly lower costs in later years. By contrast, the levelized gross plant method will recover costs in equal (or levelized) increments each year of a facility's life.

22/ (...continued)
separate sub-accounts.

23/ No party filed exceptions to the judge's finding that 0.15 percent is an appropriate allocation factor for other power production investment.

24/ The judge determined that jointly-owned units are appropriately included in the costs used to determine the VAr charge. The jointly-owned generating units here at issue are owned by Columbus Southern Power Company (an AEP affiliate), along with Cincinnati Gas & Electric Company and Dayton Power & Light Company (collectively, the "CCD" units). See 80 FERC at 65,080.

25/ The judge ruled that "CCD" units are appropriately included in the costs used to determine the spinning reserve charge.

26/ The judge determined that AEP should pay 90 percent of its decremental costs for overscheduled energy outside the bandwidth.

Positions of the Parties

AEP proposed a rate for its transmission service based on the levelized gross plant approach described above. AEP argued that it has used this approach consistently for decades. 27/ AEP further asserted that it did not propose to switch the rate design methodology for any customers other than a subset of existing and potential transmission customers (i.e., requirements customers).

WVPA, IUCC, Blue Ridge, AMP-Ohio, and trial staff argued against AEP's proposed levelized gross plant approach because:

(1) under AEP's transmission tariff, transmission customers will not be charged rates that are comparable to AEP's own use of its transmission system, and the rates therefore will discriminate against transmission customers in violation of the Commission's comparability standard;

(2) factors that supported the use of the levelized gross plant approach in cases where it was adopted are absent here; 28/ and

(3) given that AEP's system is composed of facilities with varying levels of depreciation, and the levelized gross plant method does not adjust for such depreciation, the levelized gross plant approach would produce excessive revenues for AEP.

Initial Decision

The judge found that AEP's proposed levelized gross plant methodology of calculating transmission rates results in a switch from the non-levelized net plant methodology for its requirements customers, as well as its retail customers. The judge found that, as a result of this switch,

> AEP's requirements customers (as well as retail customers who may switch to transmission service) will be paying depreciation a second time leading to an overrecovery of AEP's costs. [80 FERC at 65,052.]

27/ AEP asserts that, historically, many of its interchange service rates were developed based on the levelized gross plant approach. See Ex. A-101.

28/ For example, in Southern California Edison Company, Opinion No. 341, 50 FERC • 61,138 at 61,412 (1990) (SoCal Edison), and Jersey Central Power & Light Company, et al., 38 FERC • 61,275 at 61,927 (1987) (Jersey Central), the company historically had used the levelized approach.

The judge also found that AEP did not demonstrate that its proposal meets the Commission's comparability standard as set forth in the Commission's Transmission Pricing Policy Statement. 29/ In this regard, the judge explained that AEP uses a non-levelized net plant approach for its native load customers while proposing a levelized gross plant approach for non-native load customers. He concluded that,

> [b]ecause AEP's open access tariff does not offer third parties access on the same or comparable basis [as AEP's use of its system], AEP's levelized approach violates the Commission's comparability standard. [80 FERC at 65,053.]

Moreover, the judge found that Commission precedent does not support AEP's proposal to use the levelized gross plant method for transmission service. In particular, the judge noted that AEP's citations to SoCal Edison and Jersey Central are inapposite because the circumstances in those cases are distinguishable from those present here, where AEP is proposing to switch depreciation methods after nearly one-third of AEP's transmission system already has been depreciated without making adjustments to prevent overrecoveries. The judge found the non-levelized net plant methodology appropriate to design rates for AEP's wholesale transmission service.

Exceptions

AEP filed an exception to the judge's rejection of its proposed levelized gross plant transmission rate design. AEP claims that the judge erred in failing to recognize that: (1) the Commission has previously found that the gross plant and net plant methods recover identical costs over the lives of the assets, and the rate differences between the two methods is simply the result of a timing difference in cost recovery; (2) AEP was not proposing a "change" in its rate design method; (3) AEP's use of the levelized method will not result in an overrecovery of its revenue requirement; and (4) comparability does not require use of the net plant methodology.

Blue Ridge, AI, WVPA, and trial staff filed briefs opposing AEP's exception on this issue.

29/ Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, FERC Stats. & Regs. • 31,005 at 31,141-44 (1994), order on reconsideration, 71 FERC • 61,195 (1995) (Transmission Pricing Policy Statement).

Discussion

We deny AEP's exception, and affirm the judge's rejection of AEP's proposed switch to a levelized gross plant rate design. While reasonable results can be produced using either levelized or non-levelized rate methods, depending on the circumstances, see, e.g., KU, 85 FERC at 62,103-05, here we find that, based on the record before us and the circumstances presented in this case, the use of a levelized gross plant rate design by AEP would not produce a just and reasonable result. Specifically, we note that AIW and trial staff witnesses testified that this switch would result in an overrecovery of costs by allowing AEP to recover anew depreciation expense that it has already recovered. See, e.g., Exs. AIW-11 at 24-31; AIW-17; S-71 through S-84. 30/ We are not convinced by AEP's opposing arguments on this issue (e.g., AEP did not provide any studies demonstrating that there would not be higher rates if the levelized method is adopted, and AEP did not substantiate its claims that it will be adding new transmission plant in the future). See Exs. A-53 at 4 and A-100 at 7.

AEP relies on our order in SoCal Edison in support of its use of a levelized gross plant rate design because AEP has historically provided under certain circumstances long-term stand-alone transmission service under levelized rates, a circumstance that AEP states persuaded the Commission to allow requirements customers to be switched to a levelized rate in SoCal Edison. We reject AEP's argument. As we explained in Consumers Energy Company, 85 FERC • 61,100 at 61,366-67 (1998) (Consumers Energy), the approach we took in SoCal Edison is no longer appropriate. We believe that the concerns that led to our decisions in Consumers Energy, and also in KU, 85 FERC at 62,104-05, dictate that we no longer follow SoCal Edison.

As we found in KU, and restated in Allegheny Power Service Corp., 85 FERC • 61,275 at 62,117 (1998) (APS), where a utility proposes to switch from a non-levelized net plant rate design method, "[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method." 85 FERC at 62,103-05. Just as in KU and APS, AEP has not persuaded us here that the switch in current bundled requirements service is appropriate in the circumstances of this case because: (1) AEP's system is composed of facilities with varying levels of depreciation and

30/ AIW and trial staff claimed that AEP's proposed switch in methods would increase the transmission revenue requirement by $44.5 and $61.2 million, respectively. See Joint Statement of Issues at 3; and Exs. S-72 and S-74.

(2) AEP's proposed levelized gross plant method does not account for such variations. 31/

Based on the foregoing, we reject AEP's proposal to develop its transmission tariff rate using a levelized gross plant method, and we will require AEP to recalculate its tariff rates based on a non-levelized net plant method.

As we stated in Consumers Energy, 85 FERC at 61,367, "[i]t is not our intention to prohibit the use of the levelized approach in every instance. As noted at the outset, the Commission believes that a levelized methodology may produce just and reasonable rates under different circumstances." Here, AEP has not persuaded us that its proposed change in approach is appropriate in the circumstances of this case.

2. Definition of Investment Base

a. Transmission/Subtransmission "Distribution Use Facilities" Exclusions

Positions of the Parties

AEP asserted that its transmission system is operated on a fully-integrated basis and therefore it included in rate base all of its facilities classified as transmission. A secondary issue involves customer-owned facilities, and AEP did not give a credit for any customer-owned facilities.

AIW 32/ opposed this treatment, arguing that customer-owned facilities with comparable functions to AEP's facilities should be considered part of the grid, and that customers with such comparable facilities should receive credits for their own facilities that function in the same manner as AEP's facilities to integrate loads and resources. AIW claimed that AEP's proposal misdefines the transmission grid for purposes of recognizing which facilities will be deemed part of the

31/ The judge's third reason (that AEP's proposed transmission tariff does not offer third parties access to its transmission system on a comparable basis to AEP's use of its own system) is no longer applicable.

32/ Earlier in this proceeding, joint testimony was presented by AMP-Ohio, IMPA, and WVPA. The judge referred to them collectively as "AIW." 80 FERC at 65,048. The judge, in the Initial Decision uses this same abbreviation to refer to AMP-Ohio and IMPA. To clarify when WVPA is not being referred to, we will refer to AMP-Ohio and IMPA together as "AI" and will use "AIW" when referring collectively to AMP-Ohio, IMPA, and WVPA.

transmission grid, and for purposes of establishing a rate for the use of the transmission owners' facilities. AIW argued that the Commission must define the grid in one of two ways, and that under either definition AEP's approach here must be rejected. First, AIW asserted that the Commission could define the grid broadly to include all facilities that are actually used to provide service under AEP's tariff. 33/ Alternatively, AIW stated that the Commission could adopt a narrow definition of the grid that encompasses only the backbone transmission facilities that are necessary to carry any party's power from a delivery point to a receipt point on bulk transmission facilities. AIW contended that if this definition is adopted, some facilities that AEP includes in its rate base should be removed.

AEP and trial staff argued that the costs of all transmission facilities in both the network and point-to-point tariff should be "rolled-in" in developing the tariff rates. 34/ AEP and trial staff contended that AIW is attempting to insert its claims for a credit for customer-owned facilities into the issue of what is AEP's appropriate rate base for transmission. AEP and trial staff asserted that the issue of what facilities AEP should include in its rate base is different from the issue of what customer facilities are entitled to a credit. Both AEP and trial staff supported the rolled-in approach and argued that the question of credits for customer-owned facilities should not be addressed in this proceeding.

Initial Decision

The judge found that AIW's comparability and other arguments "should be appropriately advanced in a different proceeding." 80 FERC at 65,055. He also rejected arguments by AIW that certain AEP facilities should be eliminated from transmission rate base because they do not serve a network function. Based on these findings, the judge concluded that AEP's rolled-in approach should be adopted.

33/ AIW contended that this definition of the grid would better serve the goal of creating workable competitive power supply markets by eliminating discriminatory transmission pricing and encouraging all transmission owners to participate in regional transmission grids.

34/ Rolled-in transmission rates are based on the costs of the entire transmission system and reflect the fact that, when there is an integrated system, all of the facilities in the system are deemed to contribute to each use of the system.

Exceptions

AI argued on exceptions that, under Order Nos. 888 and 888-A, the standard for inclusion of transmission facilities in rate base is the same standard as for inclusion of customer-owned facilities. AI Brief on Exceptions at 10. That is,

> the Transmission Provider must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. [Id. at 9.]

AI claims that the Initial Decision failed to comply with this standard because it failed to explicitly identify what AEP transmission facilities are providing transmission service to its power and transmission customers and it failed to identify what customer-owned facilities are eligible for credits.

AI further argues that the Commission should provide an "advisory opinion" on the issue of credits for customer-owned facilities. AI Brief on Exceptions at 23-36.

With regard to AI's first point, while AEP agrees that any facilities that are not used and useful in providing transmission service should be excluded from rate base, it maintains that all of the facilities included in its rate base meet that test and are thus properly includable. AEP Brief Opposing Exceptions at 7-8.

Regarding AI's second point, AEP argues that the judge correctly found that this issue is not properly before the Commission in this case. AEP contends that this is confirmed by explicit language in Order No. 888, where the Commission stated that "cost credits related to customer-owned facilities . . . are more appropriately addressed on a case-by-case basis where individual claims for credits may be evaluated against a specific set of facts." Id. at 5, citing Order No. 888, FERC Stats. & Regs. • 31,036 at 31,743. AEP and trial staff contend that the Commission does not have before it any specific claim for credits for customer-owned facilities and therefore cannot evaluate such a request.

Trial staff also argues that the judge correctly found that the issue of customer credits should be treated when a service agreement is negotiated, and that this issue is beyond the scope of this proceeding.

Discussion

We affirm the judge's finding on this issue with regard to AI's first point. In Kentucky Power Company and Ohio Power Company, 64 FERC • 61,112 at 61,923 (1993) (Kentucky & Ohio), we stated, "[u]nder our pricing policy, it is proper for AEP companies to develop their rates on the basis of a rolled-in, system average for all grid facilities they use for transmission, not just the lines that are at delivery voltage." Accordingly, we agree with AEP's rolled-in approach to rate base and we reject AI's contention that these facilities must be more explicitly identified.

As to AI's second point, its arguments here are the same as those raised to the judge by AIW regarding its eligibility for credits for customer-owned facilities, and we do not find these claims persuasive. As we stated in Order Nos. 888 and 888-A, and in other recent orders, the question of credits for customer-owned facilities is best resolved on a fact-specific, case-by-case basis. 35/ As noted by AEP and trial staff, AI identified customer-owned facilities in this proceeding, but did not offer any support to justify a credit for such facilities. Thus, we affirm the judge's findings to accept AEP's rate base without any adjustment for customer credits.

b. Accumulated Deferred Income Taxes - Rockport 2 Plant Sale/Leaseback

Background information explaining this issue was presented in the Initial Decision, where the judge stated that:

> AEP s Rockport 2 plant was sold in 1989 for $1.7 billion and leased back for an initial term of 33 years. The gain from the sale of the plant was deferred and is being amortized, with the related taxes, over the term of the lease. AEP functionalized Accumulated Deferred Income Taxes (ADIT) based on a
>
> gross plant allocator. AEP took all of its company-wide ADIT and assigned a portion of them to the transmission function based on a fraction with plant in service related to transmission in the numerator and total plant in service in the denominator. ADIT is used to reduce the investment base for purposes of setting a transmission rate. [80 FERC at 65,055, footnote omitted.]

Positions of the Parties

AIW asserted that it is inequitable and contrary to Commission precedent to include in transmission rate base those costs related to the ADIT associated with the Rockport 2 plant

35/ See Order No. 888, FERC Stats. & Regs. • 31,036 at 31,743; Order No. 888-A, FERC Stats. & Regs. • 31,049 at 30,271; and Allegheny Power Systems, 80 FERC • 61,143 at 61,539 (1997).

sale/leaseback (Account No. 190), 36/ but not credit transmission customers with any offsetting gains related to that same sale/leaseback. 37/ Consequently, AIW proposed adjusting the functionalization of ADIT to remove ADIT relating to the Rockport 2 plant sale/leaseback. AIW claimed that the Commission previously addressed the proper ratemaking treatment of the costs and gains associated with the Rockport 2 plant sale/leaseback in Blue Ridge, where the Commission held that "ratepayers . . . are entitled to . . . the entire benefit of the sale/leaseback." 57 FERC at 61,373.

AEP's witness stated that AIW's proposed adjustment is a piecemeal approach and that, if ADIT was uniformly removed from all transmission plant, this would increase transmission plant in rate base by more than $33 million. AEP is quite willing to make this adjustment.

Trial staff agreed with AEP that AIW's proposal should be rejected because it is piecemeal. Trial staff claimed that AIW chose one item (the Rockport 2 plant sale/leaseback) and directly assigned that item to generation, and then used the plant ratio fraction for everything else. Trial staff asserts that this approach is selective and unfair. Trial staff supports AEP's original calculation.

Initial Decision

The judge found that, notwithstanding AIW's arguments to the contrary, Blue Ridge is inapposite here. In Blue Ridge, the Commission held that ratepayers are entitled to the gain from the Rockport sale/leaseback and that the shareholders are not. The issue in that proceeding did not involve ADITs. Conversely, in this proceeding, the issue is the allocation of ADITs among groups of ratepayers. Thus, the judge found that Blue Ridge does not support AIW's position. 80 FERC at 65,055.

Exceptions

AI filed exceptions to the Initial Decision where it raised arguments similar to those raised by AIW before the judge.

36/ Account No. 190 is a rate base addition; thus, by reducing the costs from this account that are included in rate base, the transmission customers' rates will be lowered. See Exs. AIW-1 at 16-17 and AIW-4.

37/ See AI Brief on Exceptions at 36-39, citing Blue Ridge Power Agency, et al. v. Appalachian Power Company, 57 FERC • 61,100 at 61,373 (1991) (Blue Ridge).

AEP and trial staff opposed AI's exception and asserted similar arguments to those they had advanced before the judge.

Discussion

We agree with the judge that AI's reliance on Blue Ridge is misplaced here. In Blue Ridge, we addressed whether ratepayers or shareholders should receive the gain on the Rockport 2 sale/leaseback, 57 FERC at 61,373, while here the issue concerns the proper allocation of ADITs between different groups of ratepayers (i.e., transmission vs. requirements customers). We find that AI is proposing a piecemeal approach that improperly focuses on a change to only one component of ADIT. AI has failed to sponsor an alternative allocation method for ADITs. Thus, we deny AI's exception and affirm the Initial Decision.

c. Generator Step-Up (GSU) Transformers

A GSU transformer is an electrical device that transforms power from a lower voltage to a higher voltage. The GSU transformers in question in this proceeding are those which step-up voltages at the generation level to higher voltages at the transmission level.

Positions of the Parties

AEP maintained that GSUs should be included in transmission rates because they perform a transmission function. AEP also argued that the inclusion of GSUs in transmission rate base is supported by Commission precedent. 38/

AI, WVPA, Blue Ridge, and trial staff argued that part of the function of GSUs is production-related and that AEP should not charge its transmission-only customers production-related costs. These participants also argued that Commission decisions supporting inclusion of GSUs in transmission rate base pre-date Order No. 888 where the Commission required utilities to offer unbundled open access transmission service. Thus, these participants argued that the cost of GSUs should be excluded from AEP's transmission rates.

Initial Decision

The judge approved AEP's proposal to continue recovering the costs of its GSUs through its transmission tariff rates. The judge found (80 FERC at 65,056-57) that this proposal was supported by Commission precedent that provides that the purpose of these facilities is to transform, or step-up, generation for

38/ AEP cited Niagara Mohawk Power Corp., 42 FERC • 61,143 at 61,352 (1988).

the purpose of transmitting power "in bulk with less loss and at less cost . . . ." 39/ While acknowledging that the precedent he relied on was from the "pre-unbundling" era, the judge nevertheless found it to be on point because, as in the instant case, it involved transmission-only service. The judge further found that trial staff and intervenors failed to counter AEP's assertion that its classification is in accord with the Uniform System of Accounts. 80 FERC at 65,057.

Exceptions

AI, Blue Ridge, WVPA, and trial staff filed exceptions to the Initial Decision raising arguments similar to those they raised at hearing.

AEP opposed each of these exceptions.

Discussion

In the past, the Commission functionalized a utility's entire cost of GSU transformers as transmission-related and allowed the utility to recover these costs through its rolled-in transmission rate. However, in KU we decided to reverse our policy in light of the Commission's unbundling of transmission and wholesale generation services in Order No. 888. As we stated in KU, given our actions in Order No. 888,

> we believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their appropriate share of the cost of services which they use. [85 FERC at 62,111.]

Our reexamination of GSU costs in KU persuaded us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates. Those same findings are applicable here. We therefore reverse the Initial Decision to reflect our revised policy on the recovery of GSU costs, as more fully articulated in KU.

3. Return on Equity

After the paper hearing, the parties to this proceeding filed a Stipulation and Agreement (Stipulation) resolving the

39/ The judge cited Minnesota Power & Light Company, Opinion No. 12, 3 FERC • 61,045 at 61,137 (1978), among other cases, for this proposition.

overall rate of return. 40/ Ex. Jt-3. The parties agreed that the overall rate of return to be used to calculate transmission rates in this proceeding would be 9.33 percent. Id. The judge did not rule on this issue; he neither accepted nor rejected the Stipulation. We accept the stipulated rate of return for the following reasons: (1) it does not exceed the upper bound of the ranges of reasonableness advocated by AEP and trial staff; (2) our analysis indicates that the stipulated rate of return is sufficient to assure confidence in the financial integrity of the company, to allow AEP to attract capital, and to provide investors with an adequate return; and (3) no party filed exceptions to it. Thus, we find that the stipulated overall rate of return is just and reasonable. 41/

4. Revenue Credits v. Demand Divisor Increase

There are two basic "off-system" ratemaking treatments: cost allocation and revenue credit. Cost allocation treats the transaction as part of the system load, with a portion of the system costs allocated to the off-system sale. Under this method, the demand divisor is increased to include the off-system transaction. Revenue crediting does not allocate costs to the off-system sale. Rather, on-system customers receive a credit for the revenues associated with the off-system sales. Thus, the off-system sale is not included in the demand divisor.

Positions of the Parties

As noted by the judge, "[t]his issue concerns whether AEP should increase its non-firm rate divisor to reflect full transmission system capability, which would make revenue crediting for non-firm rates unnecessary." 80 FERC at 65,060.

AEP advocated reflecting the demand of multi-year point-to-point transmission service in the demand divisor, while crediting other transmission revenues against its cost-of-service. Specifically, AEP proposes credits to the cost-of-service for revenues from transmission of electricity by others, interruptible service revenues and system sales revenues related to the transmission function.

40/ The signatories of the stipulation are AEP, AMP-Ohio, IMPA, Blue Ridge, WVPA, Indiana Office of Utility Consumer Counselor, and trial staff.

41/ See Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923); FPC v. Hope Natural Gas Company, 320 U.S. 591, 605 (1944).

AIW opposed revenue crediting, and instead argued that, with respect to non-firm rates, the appropriate cost divisor is transmission system capability as measured by AEP's generating capacity plus firm, long-term transactions. AIW asserted that the use of revenue credits to offset the non-firm revenue requirement is inappropriate because revenues from the use of excess capacity of the transmission system are already accounted for in the demand divisor.

Trial staff opposed both the AEP and AIW approaches, and argued that AEP should include all firm transmission service demand in the demand divisor, and credit only revenues from non-firm transmission service against the cost of service, as this would be consistent with Commission's precedent. Specifically, trial staff contended that its approach is consistent with Order No. 888 wherein the Commission stated that it would allow point-to-point firm transmission rates to be based on adjusted monthly system peak loads, which it defined as:

> the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service. [42/]

Initial Decision

The judge found that trial staff's proposed method was supported by the provisions of Order No. 888. He therefore adopted trial staff's proposal stating that:

> a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes. [43/]

Exceptions

AI filed exceptions to the judge's findings, arguing that the judge failed to address its proposal that the denominator for this service should be set at an amount equal to "AEP's generating capacity plus firm contract demands." AI Brief on Exceptions at 53. In essence, AI contends that: (1) the Commission recognizes that most non-firm service is less valuable

42/ Order No. 888, FERC Stats. & Regs. • 31,036 at 31,738.

43/ 80 FERC at 65,061, citing Order No. 888, FERC Stats. & Regs. • 31,036 at 31,738.

and should be priced below the level of firm service; and (2) this should be accomplished through the use of a larger divisor, and therefore a lower rate.

AEP and trial staff oppose AI's exception. Trial staff agrees with AI's first contention, but not the second. Trial staff states that where the non-firm rate is a ceiling, or "up-to" rate capped at the firm rate (as here), the Commission has consistently allowed this treatment. Trial staff contends that the use of the same divisor for both non-firm and firm services and capping the non-firm rate at the firm rate is consistent with Commission precedent, the Commission's Pricing Policy Statement, and Order No. 888. 44/

Discussion

We reject AI's argument that the Initial Decision did not squarely address its proposal. As noted by the judge, we resolved this issue in Order No. 888, where we concluded that it is appropriate for non-firm service to be priced using up-to rates with the ceiling rate set at the firm service rate. 45/ In addition, we agree with trial staff that AEP should include the demand for all firm transmission service in the demand divisor, and only credit revenues from non-firm transmission against the cost of service. Thus, we conclude that AI's exceptions raise no arguments not already considered and rejected by the judge, and we affirm the findings of the judge on this issue.

5. Demand Divisor

This issue involves the development of the demand divisor for firm transmission rates.

Background

Initially, AEP proposed a non-customer-specific firm point-to-point transmission rate based on a 12 CP demand divisor. 46/

44/ Trial Staff Brief Opposing Exceptions at 58-60, citing, e.g., Central Maine Power Company, 54 FERC • 61,206 at 61,612 (1991); Transmission Pricing Policy, FERC Stats. & Regs. • 31,005 at 31,137 (1994); and Order No. 888, FERC Stats. & Regs. • 31,036 at 31,743-44.

45/ Order No. 888, FERC Stats. & Regs. • 31,036 at 31,743-44.

46/ 64 FERC at 62,977. Demand allocation determines the charge allocated to a class of customers. Under the 12-month coincident peak method, commonly known as the 12 CP method, demand is allocated by taking the hour of highest usage (the
(continued...)

In our order setting AEP's filing for hearing, we summarily rejected AEP's proposal, citing our precedent in Southern Company Services, 61 FERC • 61,339 (1992) (Southern). We gave AEP the option of developing a "customer-specific" rate by allocating AEP's total transmission-related revenue requirement using a customer-specific revenue requirement using those customers' 12 coincident peaks and billing determinants, or to develop a non-customer-specific rate using a 1 CP demand divisor. AEP elected to maintain its non-customer specific approach, but nonetheless filed a request for rehearing, asking us to allow it to use a 12 CP demand divisor in conjunction with a non-customer-specific revenue requirement. We denied rehearing on this issue and directed AEP to use the annual system peak (1 CP) as the demand divisor. 67 FERC at 61,487. AEP complied with the Commission order and filed a 1 CP demand divisor. 47/ AEP did not file a petition for review of the Commission's orders.

Positions of the Parties

Notwithstanding that the issue was rejected by summary disposition and was not set for hearing, AEP attempted to preserve and litigate this issue at hearing and continued to advocate a 12 CP demand divisor throughout the proceeding. AEP argued that in Order No. 888 the Commission changed its policy with respect to the use of a 12-CP demand divisor when a tariff allows full flexibility for point-to-point service. AEP contended that its tariff (filed in connection with its offer of settlement and Order No. 888) allows this full flexibility, and the use of a 12 CP demand divisor is thus appropriate. AEP Initial Brief at 26-27.

Initially, trial staff supported AEP's request to use a 12 CP allocator based largely on the reasons given by AEP. Trial staff argued that Commission precedent supports the use of a 12 CP divisor when the average of the 12 monthly peaks to the single peak is more than 84 percent of the single system peak. Trial staff asserted that this average for AEP's system is 89.9 percent. Trial Staff Initial Brief at 49.

46/ (...continued)
coincident peak) in twelve consecutive months, determining the percentage of peak use by each customer class during each of the twelve months, and averaging the resulting percentages for each customer class. By contrast, the 1 CP method allocates demand among customer charges based on the annual coincident peak.

47/ AEP proposed a 1 CP demand divisor of 17,753 MW, reflecting its 1992 internal peak minus its interruptible loads and generator direct loads, plus 1,258 MW of firm contract demand. Ex. A-22.

AIW argued that the Commission's orders setting this proceeding for hearing summarily dismissed the 12 CP divisor as an issue in this proceeding. Thus, AIW asserted the adoption of a 12 CP rate at this late date would be both unfair and legally impermissible in this proceeding. Blue Ridge and WVPA also argued that the 12 CP v. 1 CP issue is no longer within the scope of this proceeding.

In addition to opposing AEP's 12 CP proposal on procedural grounds, intervenors also opposed the method AEP used to develop its 1 CP divisor. AIW argued that AEP's 1 CP calculation should be adjusted to include: (1) an additional 329 MW of demand associated with long-term transmission contracts; (2) 890 MW of generator direct loads served by AEP; 48/ and (3) the Buckeye Power Cooperative (Buckeye) load as a long-term load. 49/

Blue Ridge and WVPA argued that the peak demand used as the divisor should be 35,000 MW, which is the projection of AEP's transmission system capability. Blue Ridge and WVPA base this argument on a technical paper prepared by an AEP engineer stating that the system was designed to serve an expected load of 35,000 MW. 50/ However, if this approach is rejected in favor of using an annual system peak, then alternatively Blue Ridge advocated using AEP's 1993-94 winter peak (25,194 MW). Blue Ridge

48/ AIW and trial staff argued that another 890 MW should be added to AEP's 1 CP demand divisor to reflect certain generator direct served loads (two specific retail loads, see AEP Brief Opposing Exceptions at 22), because the transmission facilities serving the two specific retail loads are routinely included in AEP's transmission planning and load flow studies. Exs. S-72; AIW-20; and AIW-11 at 39-43.

49/ AEP opposed including in the demand divisor firm transmission service AEP provides to Buckeye. AEP acknowledged that this is a resource/load integration type transaction, but it then argued that this transmission should not be included in the demand divisor because resource/load integration type service is not offered under its open access tariff. Ex. AEP-55. AIW argued that AEP's position is no longer valid because AEP is now offering network integration service. Therefore, AIW contended that the Buckeye loads should be included in the demand divisor. Ex. AIW-11 at 38-39. The Buckeye load is 937 MW, which AEP included as load for purposes of a 12 CP divisor.

50/ By comparison, the judge found that the single system peak during the test year was 18,598 MW (80 FERC at 65,064) and AEP's highest system peak occurred in 1993-1994, when total load reached 25,174 MW (80 FERC at 65,065).

contended that this peak represents AEP's proven transmission system capability, and is "a more credible proxy for transmission system capability than use of a test year peak exceeded in prior or subsequent years." Blue Ridge Initial Brief at 18.

Initial Decision

The judge noted that the Commission had considered the issue of 1 CP vs. 12 CP in both its hearing order and its order on rehearing in this proceeding, and that the Commission had rejected AEP's proposed use of the 12 CP method in both instances. The judge also found that, while Order No. 888 now allows utilities to use a 12 CP demand divisor in their point-to-point tariffs, it did not mandate the use of this method. Thus, the judge rejected AEP's proposed 12 CP methodology. 80 FERC at 65,066. 51/

The judge found the appropriate divisor to be 17,753 MW as calculated by AEP using a 1 CP demand divisor. The judge rejected Blue Ridge's contention that the peak should be based on the 1993-94 winter peak because the proceeding is based on 1992 test year costs.

Exceptions

While supporting the Initial Decision's adoption of a 1 CP approach, Blue Ridge filed exceptions arguing that the judge erred by relying on AEP's test-year peak figures to obtain the demand divisor and by failing to consider alternatives suggested by Blue Ridge and other interveners. In particular, Blue Ridge argues that the judge failed to consider peak loads subsequent to the test year (e.g., the 1993-94 winter peak) as a measure of system capability. Blue Ridge argues that consideration of these loads would yield a demand divisor of 25,194 MW, an amount that Blue Ridge claims represents AEP's proven transmission capability. 52/

AI and WVPA filed exceptions to the Initial Decision reiterating the arguments they made before the judge in support of their proposed 1 CP divisor.

AEP also filed exceptions to the Initial Decision and argues that the Commission is not legally precluded from using a 12 CP

51/ The judge did not dispute that AEP may propose a 12 CP methodology in future proceedings, but agreed with AIW that this would require a new section 205 filing.

52/ Blue Ridge Brief on Exceptions at 12-15. This figure is the highest monthly peak demand AEP had reached as of the date Blue Ridge filed its initial testimony.

divisor, and that the evidence AEP has submitted here supports the use of a 12 CP divisor.

Trial staff filed exceptions to the judge's method of calculating the single peak, arguing that it is inconsistent with both Order No. 888 and the methodology adopted by the judge in the Initial Decision. 53/ Trial staff further argues that the rationale underlying the 1 CP figure adopted by the judge is inconsistent with the determinations reached by the judge elsewhere in the Initial Decision. 54/ Trial Staff Brief on Exceptions at 20-24. However, trial staff supported the judge's determination that AEP should be precluded, for procedural reasons, from use of the 12 CP divisor in this proceeding. Trial Staff Brief Opposing Exceptions at 29-30.

AEP, AI, WVPA, Blue Ridge, and trial staff filed briefs opposing exceptions.

Discussion

We find AEP's efforts to preserve and litigate this issue at hearing unavailing. We therefore reject AEP's exception advocating the use of a 12 CP divisor, and we affirm the judge's adoption of a 1 CP divisor in this proceeding.

We summarily rejected AEP's 12 CP proposal in both our initial hearing order (64 FERC at 62,976-77) and in our order on rehearing (67 FERC at 61,487). 55/ By summary disposition, we made a final determination resolving this issue and removing the issue from further consideration in this proceeding. Any timely challenge to this final determination would have had to have been made in a petition for review to the U.S. Court of Appeals,

53/ Trial staff's calculation started with AEP's monthly firm peak load, then subtracted the monthly coincident peaks associated with all firm point-to-point customers and added the monthly contract demand reservations for firm point-to-point service. This results in a 1 CP demand divisor of 19,537 MW.

54/ For example, in his ruling on the treatment of revenue credits, the judge ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

55/ The hearing order also gave AEP guidance on what cost support should be submitted in a new filing seeking the use of a 12 CP demand divisor. 64 FERC at 62,977.

seeking appeal of this determination. However, no such appeal was filed.

Moreover, to allow AEP to pursue this issue now would be unfair to Intervenors who, based on our prior orders, quite properly understood that this issue was no longer within the scope of this proceeding. 56/ Thus, regardless of any subsequent changes in Commission policy, it would be unfair and prejudicial to the other parties -- and a violation of their due process rights -- for us to consider anew the merits of AEP's 12 CP proposal at this late stage of the proceeding. 57/

While AEP correctly notes that in Order No. 888 we revised the policy we earlier had enunciated in Southern (and which we relied on in our earlier orders to dismiss AEP's 12 CP proposal), AEP fails to consider two important factors that relate to this change in policy. First, as noted by the judge, 80 FERC at 65,066, in Order No. 888 we did not give transmission providers an automatic and immediate right to develop their rates using a 12 CP divisor; rather, we stated that commencing with the ordered improvements in the tariff services we would no longer summarily reject filings on this basis but would instead allow transmission providers seeking a 12 CP divisor to make a filing with the Commission supporting such a proposal and to pursue this at hearing. 58/ Following the Commission's issuance of Order No. 888, AEP had the option of filing a new section 205 rate case, seeking Commission approval to use a 12 CP demand divisor in conjunction with non-customer-specific rates. It chose not to do so.

AEP instead chose to continue to raise this issue in the instant proceeding (based on our issuance of Order No. 888), even though Order No. 888 was issued nearly three years after the Commission's hearing order removing the 12 CP issue from this proceeding. However, as discussed above, due to the finality of our decision on this issue in this proceeding, we reject this

56/ See AI Initial Brief at 56-57; AI Brief Opposing Exceptions at 31-33; WVPA Brief Opposing Exceptions at 15-16; and Blue Ridge Brief Opposing Exceptions at 12-14,

57/ This is true regardless of the judge's decision to receive into evidence AEP testimony in support of a 12 CP proposal. It is within the purview of the Commission, not of the judge, to define the scope of a proceeding and the Commission already had reached a determination on the 12 CP issue when it set this case for hearing before a judge.

58/ Order No. 888, FERC Stats. & Regs. • 31,036 at 31,737-38. See also Order No. 888-A, FERC Stats. & Regs. • 31,048 at 30,263.

effort. For these reasons, we reject AEP's proposal to allow it to develop its point-to-point transmission rates using a 12 CP divisor.

AEP advocated a 1 CP demand divisor of 17,753 MW, which was adopted by the judge, but, as pointed out by AIW and trial staff, this number is inconsistent with other determinations in the Initial Decision. We reject 17,753 MW as 1 CP demand divisor. Trial staff proposed a 1 CP demand divisor of 19,537 MW, which is derived by adding the following: (1) 16,495 MW - adjusted internal peak load; 59/ (2) 799 MW - for firm contract demand; (3) 1,304 MW - for firm transmission for others; (4) 890 MW - for two specific retail loads; 60/ and (5) 49 MW - for the Indianapolis P&L sale. We adopt trial staff's proposed 1 CP demand divisor with one modification. 61/ We affirmed the judge's decision to treat the Indianapolis P&L sale as a revenue credit; therefore, we modify trial staff's proposal by adopting 19,488 MW (19,537 MW minus 49 MW) as the 1 CP demand divisor.

6. Appalachian Pricing Method Issues

Appalachian pricing is a rate design method approved by the Commission for short-term service expected to be taken only during peak periods. The hourly charge is developed assuming usage of 16 hours a day, five days a week, 52 weeks a year (i.e., 4,160 hours per year) in contrast to the 8,760 total hours in a year. 62/ Under this rate design, 100 percent of the annual cost of service is equally distributed to each of the 52 weeks in a year; 100 percent of the weekly cost is equally distributed to five of the seven days in a week (Saturday and Sunday are off-peak days and are excluded); and 100 percent of the daily (weekday) cost is equally distributed to 16 of the 24 hours in a

59/ See Exhibit A-24.

60/ Trial staff claimed that the Buckeye load of 937 MW is included in the 1,304 MW. Trial Staff Brief Opposing Exceptions at 34.

61/ We start with AEP's proposed internal peak load of 16,495 MW (item 1). We add to this trial staff's proposed adjustments for long-term firm transmission service (items 2 and 3) and 890 MW (item 4) for two specific retail loads (as argued by AIW and trial staff). We subtract 49 MW (item 5), based on our findings on the Indianapolis P&L sale.

62/ See Appalachian Power Company, 39 FERC • 61,296 (1987) (Appalachian).

day (the other 8 hours are off-peak hours and are excluded). 63/ In addition, to prevent over-recovery, this rate is accompanied by a proviso that no customer can be charged more than the equivalent daily or weekly rate (e.g., charges for hourly usage are capped at the equivalent daily rate). 39 FERC at 61,964-65. The Appalachian rate design method was established on the theory that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. Id. at 61,965.

Positions of the Parties

AEP proposed to use the Appalachian method for developing its hourly and daily transmission rates for short-term transmission service. Trial staff generally supported AEP, arguing that it is appropriate for AEP to develop its on-peak hourly and daily rates using the Appalachian method, but only if it also offers off-peak service with hourly and daily rates developed using seven days for daily service and 8,760 hours for hourly service.

AIW and Blue Ridge contended that the Appalachian method should be abandoned and a pricing method that encourages economically efficient transactions should be used instead. They further contended that trial staff's approach is not sufficient because the only reasonable method for time-differentiation is to reduce the off-peak rates, not to raise the on-peak rate even further above the cost of service (which they claim would be the result of trial staff's proposal). AIW argued that AEP should use system capacity as the denominator to calculate the non-firm rate because they contended that system capacity represents a conservative measure of AEP's actual capability. In addition, an AIW witness proposed a six day divisor for daily service.

Initial Decision

The judge found trial staff's peak/off-peak proposal to be a reasonable adjustment to the Appalachian method for this proceeding. He stated:

> Staff's proposal achieves the Commission goal of recovering [costs] from those who take service at the time of the peak 4,160 hours while off-peak rates are based upon a distribution of annual costs over all 8,760 hours. [80 FERC at 65,069.]

63/ The use of a five day week, 16 hour day and 52 week year results in 4,160 peak hours in a year.

Thus, the judge reasoned, customers using short-term transmission service during off-peak hours do not constrict the system during the critical load period and should pay less than they would under the Appalachian method. Therefore, the judge found that trial staff's proposal would result in just and reasonable rates, and he adopted it. Id.

Exceptions

AI and WVPA claim that the Initial Decision is internally inconsistent because on the one hand it rejects using the Appalachian method in developing hourly rates for short-term transmission system sales and buy/sell transactions, while on the other hand it approves the Appalachian method for non-firm transmission rates. 64/ AI and WVPA argue that the Commission should find that an 8,760 hour year should be used in determining on-peak non-firm hourly rates for both revenue credits and unit rates in the Open Access Tariff. 65/ AEP and trial staff oppose AI's and WVPA's exceptions.

Discussion

The theory behind Appalachian pricing is that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. 39 FERC at 61,965. We have previously determined that Appalachian pricing is not warranted where it has not been shown that 16 hours is a good proxy for total daily usage.

We disagree with AI's and WVPA's contention that the Initial Decision is internally inconsistent because it uses the Appalachian method for non-firm transmission rates but not for certain revenue credits. AI and WVPA are referring to bundled non-firm, short-term system power sales transactions that AEP engaged in during the 1992 test year. AEP reflected a credit of $25.8 million for the transmission component of the non-firm short-term system power sales to which AI refers. These transactions occurred prior to open access. Therefore, AEP did not separately calculate a transmission component for these bundled power sales, but instead estimated a transmission revenue credit, thereby reducing the cost of service by the estimated

64/ AI and WVPA ask us to compare the judge's finding basing credits for buy/sell and off-system sales on an 8,760 hour test year (which we affirmed summarily, see note 18 supra) to his ruling using a 4,160 hour year for determining the on-peak non-firm transmission rate (80 FERC at 65,068-69).

65/ WVPA Brief on Exceptions at 22; AI Brief on Exceptions at 58-60.

transmission credit. The Initial Decision approved the estimate as reasonable, 80 FERC at 65,062, and we affirm this finding for the reasons stated by the judge. Intervenors have not contended that AEP's proposal would result in unjust and unreasonable rates or in an overrecovery of costs. Instead, they argue it is inconsistent with other findings made in the Initial Decision. As mentioned above, we disagree. Therefore, there is no impediment to accepting AEP's proposal and rejecting the arguments of AI and WVPA.

Accordingly, we affirm the finding of the judge on this issue.

B. ANCILLARY SERVICES RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

Positions of the Parties

AEP recommended using the levelized gross plant methodology to determine rates for ancillary service. AEP explained that its reasoning for using this methodology is the same as discussed for base transmission rates. However, AEP believed that where services are available from third parties, rates should be market-based rather than cost-based. AEP Initial Brief at 32.

AIW argued that ancillary services rates should be developed using non-levelized net plant methodology.

Trial staff argued that three of the six ancillary services -- Regulation and Frequency Response Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service -- are not monopoly services because transmission customers can provide these services and put a downward pressure on the prices offered by AEP. Moreover, trial staff argued that AEP's levelized gross plant rates are "up to" rates that AEP can discount on a non-discriminatory basis. Based on this, trial staff concluded that developing rates for these three ancillary services on a levelized gross plant is not unreasonable.

Initial Decision

The judge found that the non-levelized net plant methodology for developing ancillary services rates is appropriate for the same reasons as discussed with respect to transmission rates.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative and determine that AEP's proposal to price these ancillary services using the levelized gross plant method is reasonable. We have repeatedly approved the use of the levelized gross plant method of pricing as a reasonable approach. Although in this proceeding, as in KU, we have rejected company proposals to use a levelized gross plant method to price transmission tariff rates, this was because these cases involved company proposals to switch pricing methods (from a non-levelized net plant pricing to a levelized gross plant pricing) in mid-stream for what were similar transmission services. It is this switching of methods, and not the levelized gross plant method itself, that we find has led to the development of rates that have not been shown to be just and reasonable. Conversely, here there is no switching of methods involved because these ancillary services are new services that were not previously provided as separate services. This is a key distinction that makes the KU precedent on the pricing of transmission rates inapposite here.

For these reasons, and because no party has shown that the ancillary rates produced by AEP's levelized gross plant method are otherwise unjust, unreasonable or unduly discriminatory, we adopt AEP's pricing approach.

2. Scheduling, System Control and Dispatch Service

We agree with the judge that there are no remaining issues involving this ancillary service. 80 FERC at 65,071. Ex. Jt-1 at 21. The per unit rates will be affected by the cost divisor ultimately found just and reasonable, which we find is the same divisor we found proper for the base transmission rate -- 19,488 MW. See section III.A.5 above.

3. Reactive Supply and Voltage Control (VAr)

a. Active and Reactive Allocation Factor

Positions of the Parties

AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function." AEP Initial Brief at 37. While both AEP and trial staff generally agreed on the methodology to calculate allocation factor applicable to reactive production, 66/ they disagreed on the location at which the reactive capability should be measured. Depending on the measuring point location chosen, costs will be shifted between customers taking transmission service and native load customers. AEP asserted that the name-plate reactive capability at the generator terminals should be used. 67/ Trial staff explained that some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs, before it reaches the transmission system. 68/ Accordingly, trial staff argued that the Commission should not use the generator's nameplate reactive capability, but instead should use the reactive capability at the GSU terminals available to the transmission system. Ex. S-88. Thus, while AEP proposed a reactive power allocation factor of 21 percent, trial staff recommended only 11.47 percent.

AEP, however, maintained that the GSUs should remain a part of the transmission system. Also, even if GSUs are functionalized to production, AEP argued that despite the reactive power losses associated with auxiliary loads and GSUs, the generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Reply Brief at 43.

Initial Decision

The judge found merit in AEP's argument that there must be enough reactive power remaining at the transmission terminal to provide the voltage control support on the system. Accordingly, he determined that AEP's proposed 21 percent allocation factor for reactive power measured at the generator terminals was just and reasonable. 69/

66/ The parties agreed to use the formula $MVAr^2/MVA^2$ to determine the allocation factor.

67/ AEP maintains that reactive capability should be measured at generator terminals (the low-voltage side of the GSU), while trial staff maintains that it should be measured at the GSU terminals nearest to the transmission system (the high-voltage side of the GSU).

68/ As noted earlier, trial staff argued that the GSUs should be refunctionalized to production.

69/ 80 FERC at 65,079. The judge found that the GSUs perform transmission functions. Id. He therefore did not reach trial staff's contentions that relied on the facilities (continued...)

Exceptions

Trial staff filed exceptions arguing again that, during the step up of power and energy from the generator terminal voltage to transmission voltage, some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs. In its exceptions, trial staff reiterates its position that the critical issue here is whether GSUs perform a transmission function or a generation function. Trial staff argues that the judge erroneously determined that the GSUs should be assigned to the transmission function, and that, consequently, the reactive power losses in the GSUs belong to the transmission function. However, trial staff contends that the judge's finding was erroneous. Trial staff states that, in the event the Commission reverses the judge on GSUs, it should adopt the trial staff's reactive power allocation factor of 11.47 percent. Trial Staff Brief on Exceptions at 32-33.

In its Brief Opposing Exceptions, AEP disagrees with trial staff's contention that the functionalization of GSUs to transmission or production is controlling on this issue because the allocation factor is based on capability. AEP argues that, irrespective of the location at which reactive power capability is measured, the generating equipment must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Brief Opposing Exceptions at 37-38.

Discussion

We adopt the judge's finding that 21 percent is the appropriate allocation factor to segregate the costs of reactive (VAr) production from those of active (Watt) production. We are not persuaded by trial staff's assertion that the reactive capability of the generators should be reduced by the VArs consumed by GSUs and auxiliary loads before developing an allocation factor. We agree with AEP (and the judge) that the allocation factor should be based on the capability of the generators to produce VArs and that this capability should be measured at the generator terminals. We find merit in AEP's assertion that a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission

69/ (...continued)
being deemed to perform generation functions.

system. 70/ See AEP Reply Brief at 43. For these reasons, and for the reasons stated by the judge in the Initial Decision, we affirm the judge's ruling on this issue in the Initial Decision.

b. Unrelated O&M Expenses

Positions of the Parties

AEP proposed to include all O&M expenses that are directly and indirectly related to the production of reactive power in its carrying charge rate 71/ of 22.1 percent. AEP claimed that its methodology excludes O&M expenses unrelated to reactive power production. Exs. A-28 at 1; and A-95. Trial staff agreed. Trial Staff Reply Brief at 39.

AIW argued that AEP's method will lead to an overrecovery of its O&M expenses because in developing its carrying charge, AEP improperly included costs from O&M accounts that have no direct relation to the production of reactive power. AIW also argued that AEP's method allocates O&M expenses on a different basis than it allocates plant costs related to VAr production. In addition, AIW argued that AEP should remedy the problem by performing an account-by-account analysis of which O&M costs are actually related to the production of reactive power, and that only those costs should be included in the development of the fixed charge rate. Ex. AIW-11 at 58. AIW Initial Brief at 70-71.

AEP disagreed with AIW's argument that O&M expenses indirectly related to production equipment should be excluded from the development of the carrying charge rate because they do not directly contribute to reactive power production. AEP Initial Brief at 39-40. AEP further stated, "[t]here is no production equipment [that] does not contribute to reactive power production." Ex. A-53 at 43.

Initial Decision

The judge ruled that AIW's method of allocating O&M expenses related to reactive power production is superior to AEP's method because AIW logically assigned O&M expenses to the VAr producing equipment in the same proportion as its investment in such equipment. The judge found that AEP had not justified why O&M

70/ However, we will require AEP to recalculate the transmission loss factor to exclude real power losses that take place in GSUs.

71/ Carrying charge is a component of revenue requirements that provides for the return of and on capital invested in plant, taxes, and insurance premiums.

expenses related to VAr production should be allocated on a different basis than the plant costs related to VAr production, and he thus rejected AEP's proposal (which would have produced higher rates). The judge found AIW's approach to be reasonable because it provided for a consistent treatment of the plant costs and O&M expenses related to VAr production. The judge also found that AEP's argument (that there is no production equipment that does not contribute to reactive power production) is unavailing because the issue here does not concern the total exclusion of the O&M expenses from the VAr charge, but instead involves the proper allocation of O&M expenses to the VAr charge. However, the judge noted that in accordance with his ruling that the non-levelized net plant method is appropriate for developing ancillary services rates, the issue of allocation of O&M expenses is moot because there will be no carrying charge under the non-levelized method. 80 FERC at 65,081-82.

Exceptions

No party filed exceptions on this issue.

Discussion

In accordance with our ruling approving AEP's use of a levelized gross plant rate design for developing the ancillary services rates, the proper allocation of reactive power O&M expenses is no longer moot. We affirm the judge's finding that AIW's method of allocating reactive power O&M expenses is superior to AEP's method for the reasons stated in the Initial Decision.

4. Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response)

a. Pricing for Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service

Positions of the Parties

AEP proposed to allocate the minimum East Central Reliability Council (ECAR) requirement of a 6 percent operating reserve level as follows: 1.5 percent for Regulation and Frequency Response Service; 1.5 percent for Spinning Reserve Service; and 3 percent for Supplemental Reserve Service. AEP Initial Brief at 40-41.

While no party took issue with AEP's allocation of 3 percent for Supplemental Reserve Service, trial staff, AIW, and IUCC disagreed with AEP's method of dividing the 3 percent ECAR minimum Spinning Reserve in equal amounts between Regulation and

Frequency Response and Spinning Reserve. 72/ Noting that there are no industry guidelines available on this matter, and that AEP failed to provide data to track moment-to-moment variations (which would have enabled the parties to more accurately allocate this 3 percent figure), trial staff developed its own 4-step method based on AEP's hour-to-hour load deviations. In developing its 4-step method, trial staff made four "simplifying assumptions." 73/ Using that method, trial staff calculated 1 percent for Regulation and Frequency Response Service and 2 percent for Spinning Reserve Service. 74/ AEP opposed trial staff's proposed allocation and methodology, contending that several of the underlying assumptions made by trial staff served to understate the amount of capacity needed for regulation and frequency response service to follow load.

Initial Decision

The judge rejected AEP's criticism of trial staff's approach as conclusory and found that AEP neither provided data to track moment-to-moment variations nor any evidence to support its claim that trial staff's estimate for regulation and frequency response service was understated. The judge also noted that although AEP stated in its Initial Brief that it would discuss this issue in detail in its Reply Brief, AEP's Reply Brief does not even address operating reserves. AEP Initial Brief at 41. The judge then held that until a standard is developed and endorsed by the Commission, trial staff's formula is reliable to calculate the level of Regulation and Frequency Response Service for AEP. Thus, the judge allowed AEP to recover 1 percent of its production costs for the provision of Regulation and Frequency Response Service and 2 percent for the provision of Spinning Reserve Service.

Exceptions

AEP filed exceptions to the judge's decision and argues that trial staff's four "simplifying assumptions" are not representative of actual AEP operating conditions. AEP asserts that, in addition to a Spinning Reserve requirement of three

72/ The parties agreed that AEP carries a total of 6 percent of capacity to provide for the following three ancillary services: (1) Regulation and Frequency Response Service, (2) Spinning Reserve Service, and (3) Supplemental Reserve Service.

73/ Trial staff's "simplifying assumptions" are described in Trial Staff's Brief Opposing Exceptions at 40.

74/ Trial Staff Initial Brief at 65. AI Initial Brief at 71. IUCC Initial Brief at 30-31.

percent, an additional three percent is required for Regulation and Frequency Response Service merely to follow the load trend (for a total of six percent). Nevertheless, AEP proposes only to recover a Regulation and Frequency Response Reserve of 1.5 percent and a Spinning Reserve of 1.5 percent (for a total of three percent). AEP Brief on Exceptions at 34.

Trial staff argues that a proper breakdown between Regulation and Frequency Response Service and Spinning Reserve Service is important because a customer has fewer options available for obtaining Regulation and Frequency Response Service. Trial staff points out that while both services can be obtained from a source other than the transmission provider, Regulation and Frequency Response Service can only be provided by generators that are operated under Automatic Generation Control or some NERC-approved method that enables the generator to instantaneously follow load, thus creating technical limitations on a purchaser's ability to obtain this service from a provider other than the transmission provider. Trial staff argues that such limitations do not exist for competitively obtaining Spinning Reserve Service. Trial Staff Brief Opposing Exceptions at 36-43.

Discussion

We reverse the judge and, based on the evidence presented in the record, approve AEP's proposal that the pricing of Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service should be allocated based on 1.5 percent, 1.5 percent, and 3.0 percent of production costs, respectively. As noted above, there were no industry guidelines for the pricing of these ancillary services at the time this case was litigated, and thus AEP attempted to allocate the ECAR minimum requirement among these services. No participant has demonstrated that AEP's proposal is unreasonable, and indeed, the fact that the different approaches used by AEP and trial staff each produces a combined rate of 3.0 percent for Regulation and Frequency Response Service and Spinning Reserve Service corroborates the reasonableness of AEP's overall end result, based on the evidence presented in the record. AEP is only required to show that its proposal is reasonable; not that its proposal is the only reasonable result on this record, or that its proposal is superior to all other proposals. 75/ For these reasons, we adopt AEP's proposal.

b. Other Production Facilities

Positions of the Parties

AEP did not seek to include GSUs in developing its ancillary services rate because it included GSUs in developing its base transmission rate. However, trial staff argued that GSUs are used in providing generation-based ancillary services to transmission customers, and therefore, the cost of GSUs should be included in the rate for those ancillary services. 76/ Trial Staff Initial Brief at 72-73. AIW opposed trial staff's proposal to include GSUs in the charges for AEP's generation-based ancillary services, arguing that these services are provided at the generation bus and do not require the use of GSUs. AI Initial Brief at 71-72. Ex. AIW-46 at 20.

Initial Decision

The judge determined that, consistent with his finding that GSUs perform a transmission function, GSU costs already are allocated to transmission customers. He held, therefore, that GSUs should not be included as a cost for any of the ancillary services.

Discussion

As discussed above, in section III.A.2.c, our reexamination of GSU costs in KU persuaded us that the costs of a GSU

75/ See City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984), cert. denied, 467 U.S. 917 (1984) (utility need establish only that its proposed rate design is reasonable, not that it is superior to all alternatives); MCI Telecommunications Inc. v. FCC, 627 F.2d 322, 340 (D.C. Cir. 1980) (the standard of "just and reasonable" does not require that the rates be perfect); New England Power Company, Opinion No. 352-A, 54 FERC • 61,055 at 61,198, aff'd sub nom. Town of Norwood, Mass. v. FERC, 962 F.2d 20 (D.C. Cir. 1992) (a proposed rate design need only be shown to be just and reasonable, not superior to all alternatives).

76/ The generation-based ancillary services referred to by trial staff are: (1) Reactive Supply and Voltage Control; (2) Regulation and Frequency Response Reserve Service; (3) Operating Reserve - Spinning Reserve Service; and (4) Operating Reserve - Supplemental Reserve Service.

transformer should be directly assigned to its related generating unit, not rolled into transmission rates. In KU, we stated that:

> GSUs also perform an important function in the provision of a new category of services we identified in Order No. 888, ancillary services (e.g., Operating Reserve, Regulation and Frequency Response Service, Reactive Supply and Voltage Control). Ancillary services supplied from generation resources cannot be provided without reliance upon GSUs, regardless of where power is coming from or going to.
>
> In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using these facilities. [85 FERC at 62,112].

Therefore, we find that it is appropriate to include the cost of GSUs in developing rates for all ancillary services that are supplied from generation sources. Accordingly, we reverse the judge's finding in the Initial Decision that GSUs should not be included as a cost for any of the ancillary services, and we instead adopt trial staff's proposal to include GSU costs in ancillary services rates.

5. Energy Imbalances

Order No. 888-A defines Energy Imbalance Service as follows:

> Energy Imbalance Service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to make up the difference . . . by adjusting its energy deliveries to eliminate the imbalance. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus, the Final Rule established an hourly energy deviation band of +/- 1.5 percent (with a minimum of 1 MW) for energy imbalance. [77/]

77/ FERC Stats. & Regs. • 31,048 at 30,229. In Order No. 888-A, the Commission clarified the definition of Energy Imbalance Service provided in Order No. 888, FERC Stats. & Regs. • 31,038 at 31,960-61.

a. Deadband

Positions of the Parties

AEP offered a deviation band (also known as a "deadband") of 1.5 percent, consistent with the figure we required in Order No. 888. 78/ AIW argued that the deadband of 1.5 percent is too small and discriminates against smaller systems. AI Initial Brief at 42, AI Reply Brief at 62.

Trial staff argued that AEP complied with the Commission requirements by establishing a deadband of +/- 1.5 percent. Trial Staff Initial Brief at 73-74.

Initial Decision

The judge rejected arguments made by AIW and ruled that AEP properly included a deadband of +/- 1.5 percent, as required by Order No. 888. 80 FERC at 65,085.

Exceptions

AIW filed exceptions, generally reiterating its arguments made before the judge. 79/ In opposing AIW's exceptions on this issue, trial staff argues that changing the size of the deadband would amount to changing a term and condition of the Order No. 888 pro forma tariff, which is beyond the scope of this proceeding. AEP and trial staff point out that Order No. 888-A, while keeping the deadband at +/- 1.5 percent, modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW to address the concerns raised by smaller systems such as AIW.

Discussion

We affirm the judge. In Order No. 888-A, we addressed the issue of the size of the deviation band in detail. There, we held that a bandwidth of 1.5 percent promotes good scheduling practices by transmission customers and that the implementation

78/ When the energy imbalance is within the prescribed bandwidth, the energy may be returned in kind. When the energy imbalance is outside the bandwidth, specific rates are applicable as discussed below.

79/ AI Brief on Exceptions at 71-72; WVPA Brief on Exceptions at 23-24.

of scheduled transactions should not overly burden others. 80/ Also, as noted by AEP and trial staff, in Order No. 888-A we modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW. 81/ We therefore conclude, as did the judge, that AEP's proposals on bandwidth comply with the requirements of Order Nos. 888 and 888-A. Accordingly, we affirm the judge's finding on this issue for the reasons set forth in the Initial Decision.

b. Charges for Under-Scheduled Power

Positions of the Parties

AEP argued that a transmission customer should pay a charge of 100 mills/kWh for under-scheduled energy outside the deadband. 82/ Trial staff supported this charge stating that such a charge would act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load.

AIW argued that all under-scheduled energy should be returned in kind. However, AIW asserted that a 100 mills/kWh charge may be reasonable for under-scheduled energy which exceeds the 7.5 percent (i.e., 1.5 percent for the deviation band plus 6 percent for operating reserve services) the customer purchases from AEP or supplies itself.

Initial Decision

The judge found AIW's position that all under-scheduled power be returned in kind to be inconsistent with the Order No. 888 provision that requires a separately stated charge for such under-scheduled power. The judge also found that AEP's 100 mills/kWh charge was reasonable because such a charge accounts for the fact that the imbalances occur on an hourly basis. The judge ruled that AIW's interpretation that customers that buy operating reserves from AEP are entitled to a 7.5 percent deadband is not correct, and that Order No. 888 provides for several ways in which the customer may reduce or eliminate the need for energy imbalance service, such as dynamic scheduling.

80/ See Order No. 888-A, FERC Stats. & Regs. • 31,048 at 30,232-33.

81/ Id.

82/ 100 mills/kWh was the rate utilities typically charged their customers for emergency power service, and in Detroit Edison Company, Opinion No. --, 88 FERC • 61,--- (1999) (Detroit Edison), we recently found that energy imbalance service is similar to emergency power service.

Exceptions

AI argues that a 100 mills/kWh charge might be reasonable if the deadband is expanded to include operating reserves. However, AI contends that since the judge did not expand the deadband to include operating reserves, the charge should be no greater than AEP's out-of-pocket costs. AI and WVPA argue that the charge for energy outside the deadband is too high and not cost-justified. AI Brief on Exceptions at 72; and WVPA Brief on Exceptions at 14, 22-24.

Discussion

As we explained above, "Energy Imbalance Service" is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over a single hour. We did not intend it to be used as a substitute for operating reserves. See Order No. 888-A, FERC Stats. & Regs. • 31,048 at 30,230. Furthermore, we find that a 100 mills/kWh charge for underscheduled energy outside the deadband is reasonable because such a charge will act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load. In addition, in Detroit Edison we recently found that energy imbalance service is similar to emergency power service, and that 100 mills/kWh is the rate utilities typically have charged their customers for emergency power service. Accordingly, we affirm the judge's finding on this issue.

6. Losses

a. Reserve Margin

Positions of the Parties

AEP proposed a 20 percent reserve margin in calculating costs associated with capacity required to make up for losses. AEP explained that: (1) losses are similar to firm load; (2) losses cannot be controlled and are not subject to curtailment; and (3) transmission customers do not have to buy loss service from AEP and instead are free to make alternative arrangements to supply losses. AEP Initial Brief at 43; Ex. A-28.

AIW disagreed with AEP's proposal and argued that a transmission customer is required to provide spinning and supplemental operating reserves for the full amount of its load and losses under AEP's tariff Schedules 5 and 6. Therefore, AIW asserted that an obligation to pay for a separate 20 percent reserve margin is essentially a double charge.

Initial Decision

The judge ruled that although the transmission customers have alternative ways of supplying losses, a 20 percent reserve margin for losses on top of spinning and supplemental operating reserves of 6 percent would amount to double counting of reserves. Therefore, the judge determined that a 14 percent reserve margin is appropriate in this case for calculating capacity costs for losses.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative. Notwithstanding the fact that there were no exceptions filed to the judge's determination that a 14 percent reserve margin is appropriate, we find no basis for AEP's contention that any reserve margin is cost-justified for loss service. First, AEP has sponsored no studies or quantitative evidence showing that a reserve margin of any amount is cost-justified for loss service, and there is no Commission precedent supporting such a charge. Second, in Order No. 888 we neither required customers to take such a service from their transmission providers or for transmission providers to provide such a service. There is no basis for AEP to assess a charge under its open access tariff for a service that is not even offered under that tariff. Finally, we disagree with AEP's claim that losses are similar to firm load. In fact, AEP's provision of loss services is discretionary both for AEP and its customers. Thus, we find no justification for AEP's imposition of a charge for reserves for loss service.

b. Transmission Loss Factor

Positions of the Parties

AEP proposed a transmission loss factor of 3.6 percent. AIW contended that AEP's loss factor is excessive arguing that: (1) AEP did not provide any support that losses from theoretical load flow and other studies represent actual system losses; and (2) losses on AEP's local area network and distribution system (facilities below 69 KV) should be excluded from this loss factor calculation because many of AEP's transmission customers provide losses on their own local area networks and distribution system. To rebut AIW's claim that it was improper for AEP to roll-in the local area networks and distribution losses, AEP argued that its charging of losses associated with all transmission facilities used to provide service is in accordance with Commission policy favoring rolled-in pricing. 83/ Trial staff did not contest AEP's loss factor.

Initial Decision

The judge determined that AEP's loss factor of 3.6 percent is reasonable. The judge rejected AIW's claim regarding local area network and distribution use stating that AIW did not present any evidence to prove its claim, nor did it offer any evidence showing what percentage should be assigned to that portion of the losses allegedly associated with the distribution function. He held that AIW did not provide any arguments to rebut AEP's reliance on Kentucky Power. Specifically, that case affirmed a prior Commission order 84/ approving an increase in the AEP loss factor from 2.0 percent to 3.6 percent. The Commission held in Appalachian II that:

> AEP's proposal is entirely consistent with the Commission's requirements for charging customers for transmission losses. . . . Customers' service is provided by and priced on the basis of the AEP integrated transmission system . . . . [85/]

Exceptions

AI filed exceptions in which it generally reiterates the same arguments made by AIW before the judge. AI Brief on Exceptions at 72-73.

Discussion

We affirm the judge's finding, adopting a loss factor of 3.6 percent, for the reasons set forth in the Initial Decision. However, we note that the AEP study includes all facilities including GSUs. Because we have ruled that GSUs should be assigned to production, we will require AEP to recalculate the transmission loss factor to exclude real power losses attributable to GSUs.

83/ AEP cited Kentucky & Ohio in support of its claim. AEP Initial Brief at 43. In Kentucky & Ohio, the Commission specifically approved the rolled-in method with respect to losses on the AEP System. 64 FERC at 61,923.

84/ Appalachian Power Company, et al., 63 FERC • 61,165 (1993) (Appalachian II).

85/ Id. at 62,149.

The Commission orders:

(A) The Initial Decision issued in this proceeding on August 7, 1997 is hereby affirmed in part and reversed in part, as discussed in the body of this order.

(B) AEP is hereby directed to submit a compliance filing within 60 days of the date of issuance of this order. However, if a request for rehearing is filed, AEP shall make its compliance filing within 30 days of the date the Commission disposes of the request for rehearing.

(C) Within 30 days of acceptance of the compliance filing, AEP shall make refunds, together with interest calculated pursuant to 18 C.F.R. • 35.19a (1999). Within 15 days of the date of payment of refunds, AEP shall file a report showing the computation of refunds and interest paid. A copy of the refund report shall also be sent to the affected state commissions.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

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UNITED STATES OF AMERICA88 ferc ¶ 61, 141
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 440

American Electric Power Service) Docket No. ER93-540-006
Corporation)

OPINION AND ORDER AFFIRMING IN PART AND
REVERSING IN PART INITIAL DECISION

Issued: July 30, 1999

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service) Docket No. ER93-540-006
Corporation)

OPINION NO. 440

APPEARANCES

Edward J. Brady, and Kevin F. Duffy, on behalf of American Electric Power Service Corporation.

James N. Horwood, Mark S. Hegedus, and John W. Bentine, on behalf of American Municipal Power-Ohio, Inc., and Indiana Municipal Power Agency.

Frederick H. Ritts, and Julie B. Greenisen on behalf of Blue Ridge Power Agency.

Don F. Morton, Charles W. Ritz, III, and James A.L. Buddenbaum, on behalf of Wabash Valley Power Association, Inc.

John J. Bartus, Warren C. Wood, Richard L. Miles, and Stan Berman, on behalf of the Federal Energy Regulatory Commission Trial Staff.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

American Electric Power Service Corporation) Docket No. ER93-540-006
)

OPINION NO. 440

OPINION AND ORDER AFFIRMING IN PART, AND REVERSING IN PART, INITIAL DECISION

(Issued July 30, 1999)

I. INTRODUCTION

This proceeding is before the Commission on exceptions to an Initial Decision issued in this proceeding on August 7, 1997 (Initial Decision). [1] In this order, with certain enumerated exceptions, we affirm the findings of the presiding administrative law judge (judge).

II. BACKGROUND

This proceeding began when American Electric Power Service Corporation (AEPSC) [2] filed a transmission service and ancillary services tariff for Commission approval. The proposed tariff offered firm point-to-point transmission service, for periods as short as one month, to any "eligible utility" as defined therein. The Commission accepted the proposed tariff for filing, suspended its effectiveness and made it subject to refund, summarily disposed of certain matters, and set for hearing the justness and reasonableness of the proposed rates. [3] Requests for rehearing and clarification were

1 / American Electric Power Service Corporation, 80 FERC ¶ 63,006 (1997).

2 / AEPSC filed the application on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company (collectively "AEP"). AEPSC is a service subsidiary of AEP.

3 / American Electric Power Service Corporation, 64 FERC ¶ 61,279 (1993), order on reh'g and clarification, 67 FERC ¶ 61,168 (1994).

filed by the AEP companies and others.[4]

In its rehearing order, the Commission announced a new "comparability" standard pertaining to open access transmission tariffs. Namely,

> an open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system. [67 FERC at 61,490.]

The Commission also ordered that an evidentiary hearing be held on whether the proposed tariff was unduly discriminatory and/or anticompetitive (i.e., regarding AEP's uses of its system, any impediments or consequences of offering comparable service to others, and the costs incurred by AEP in using its transmission system). Id. at 61,490-91.

Before hearings were held, on March 29, 1995, we issued a Notice of Proposed Rulemaking in our open access rulemaking proceeding ("Open Access NOPR") in which we proposed to require all public utilities owning facilities for the transmission of electric energy in interstate commerce to file open-access transmission tariffs.[5] Attached to the Open Access NOPR were two pro-forma tariffs that set forth the non-price terms and conditions of open access point-to-point and network transmission service. We also issued a pair of orders providing guidance on the disposition of this docket and other pending transmission tariff proceedings.[6] In the Supplemental Guidance Order, public utilities such as AEP, which then were litigating the terms and conditions of comparability, were given the option of revising their tariffs to be consistent with the pro forma tariffs. Upon notice of the filing of such tariffs, the existing proceedings in the

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4 / Requests for rehearing or clarification were filed by AEP, Industrial Energy Users-Ohio, American Municipal Power-Ohio Inc. (AMP-Ohio) jointly with Indiana Municipal Power Agency (IMPA), Blue Ridge Power Agency (Blue Ridge), Wabash Valley Power Association, Inc. (WVPA), West Virginia Power Division of UtiliCorp United Inc. (West Virginia Power), and D.C. Tie, Inc. (DC Tie).

5 / Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514 (1995).

6 / American Electric Power Service Corporation, et al., 70 FERC ¶ 61,358 (1995) ("Guidance Order"), order on reh'g and clarification, 71 FERC ¶ 61,393 (1995) ("Supplemental Guidance Order"). In the Supplemental Guidance Order, the Commission provided for abbreviated filing requirements, less case-by-case litigation, and an expedited approval process for utilities such as AEP, that had voluntarily filed non-discriminatory open access transmission tariffs.

pending rate cases were to be held in abeyance awaiting a determination by the Commission of whether there were any genuine issues of material fact warranting further hearing procedures.

The parties in this proceeding held settlement discussions that resulted in a partial settlement that the judge certified to the Commission as a partially contested settlement. AEP's proposal to adopt the non-price terms and conditions of the pro forma tariffs was certified as uncontested.[7] On February 14, 1996, the Commission issued an order on the partially contested settlement in which we approved AEP's proposal to adopt the non- price terms and conditions of the pro forma tariff, with certain minor modifications proposed by an intervenor and not disputed by AEP.[8] The Commission also approved the remainder of the settlement (i.e., the pricing aspects) with respect to the participants that did not oppose the settlement. With respect to the remaining participants, the Commission remanded the contested issues to the judge for further proceedings, as deemed necessary, and for preparation of the Initial Decision.[9]

While these proceedings were pending, the Commission issued Order No. 888.[10] In response to Order No. 888, AEP submitted a revised open access transmission tariff[11] that superseded the instant tariffs, but which used the same transmission and ancillary service rates at issue in this proceeding.

In response to the Commission's directive in its order on the partial settlement, the judge established additional procedures leading to a "paper hearing" on the

7 / The Open Access NOPR proposed "pro forma tariffs." Order No. 888, issued on April 24, 1996, see note 10 infra, adopted a single pro forma tariff. The AEP partial settlement references "pro forma tariffs" because it pre- dates issuance of Order No. 888.

8 / American Electric Power Service Corporation, 74 FERC ¶ 61,132 (1996).

9 / Id. The order identified the remaining participants as AMP- Ohio, IMPA, Blue Ridge, the Cities of Cleveland and Hamilton, Ohio (Cleveland and Hamilton), the Indiana Office of Utility Consumer Counselor (IUCC), DC Tie, Electric Clearinghouse, Inc. (Electric Clearinghouse), WVPA, and West Virginia Power (collectively, intervenors).

10 / Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Cost by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

11 / On July 31, 1997, the Commission accepted the compliance filing for filing, effective July 9, 1996, subject to revision to reflect the outcome of the instant proceeding. Allegheny Power Systems, Inc., et al., 80 FERC ¶ 61,143 at 61,557 (1997).

remaining issues. The additional procedures included additional discovery, the filing of additional testimony by trial staff, intervenors, and AEP, the filing of a revised Joint Statement of Issues, and the filing of briefs before the judge and the Commission.

III. DISCUSSION

A complete list of the litigated issues was presented in the Joint Statement of Issues, and are listed in the Initial Decision. 80 FERC at 65,045-46. In the discussion below, we will focus on the contested issues and those where we reverse the findings in the Initial Decision. [12]

We summarily affirm the Initial Decision on the following issues: (1) credits for customer-owned facilities; [13] (2) the "long generator leads" and "generator outlet lines" used for AEP generation; [14] (3) the depreciation and non-income tax components of the carrying charge; [15] (4) the revenue credit flow through; [16] (5) the Indianapolis Power and Light Sale; [17] (6) the system sales and buy-sell transactions; [18] (7) the one mill adder; [19] (9) Reactive Supply and Voltage Control (VAr) - Refunctionalization of transmission investment; [20] (10) VAr - Generator and Exciter Systems Costs; [21] (11) VAr - Accessory

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12 / Our listing of the issues (in the table of contents) generally conforms with the issues identified by the judge in the Initial Decision.

13 / No party filed exceptions to the judge's finding that this issue is beyond the scope of this proceeding. 80 FERC at 65,054.

14 / The judge stated that the issue of credits should be addressed when a customer requests service. 80 FERC at 65,057. The judge also noted that the Commission determined that the Rockport lines serve a transmission function and should be functionalized to transmission. See id. citing American Electric Power Service Corp., 37 FERC ¶ 63,032 (1987), aff'd in pertinent part, 44 FERC ¶ 61,206 (1988).

15 / This issue is moot because we affirm the judge's use of a net plant methodology.

16 / We deny an intervenor's request to note or take official notice of the figures found in AEP's Account No. 456 as reported in AEP's FERC Form No. 1 because they do not fall within the test period.

17 / The Indianapolis P&L sale began after, and was thus not counted in, AEP's single system peak, therefore, the judge did not include this sale in the 1 CP demand divisor. Instead, the judge adopted a revenue credit proposal.

18 / No party filed exceptions to the judge's finding adopting AIW's proposal to use 8,760 hours to develop the hourly unit rate. 80 FERC at 65,062.

19 / No party filed exceptions to the judge's finding rejecting the one-mill adder. Id. at 65,070.

20 / The judge found that AEP does not have to refunctionalize its transmission investment because Order No. 888 established "Reactive Supply and Voltage Control

Electric Equipment Costs; [22] (12) VAr - Other Power Production Investment; [23] (13) VAr - jointly-owned units; [24] (14) Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response) - CCD Units; [25] and (15) Energy Imbalances - Charges for Over-Scheduled Power. [26] We find that the Initial Decision properly decided these issues and the arguments on exceptions have failed to persuade us that the Initial Decision erred or that additional discussion is necessary.

A. TRANSMISSION RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

The issue here is the same as that previously addressed by the Commission in Kentucky Utilities Company, Opinion No. 432, 85 FERC ¶ 61,274 at 62,100-05 (1998) (KU), i.e., whether a levelized or non-levelized rate design is appropriate for developing the companies' rates for unbundled transmission service.

The non-levelized method generally will recover higher costs in the early years of a facility's life and increasingly lower costs in later years. By contrast, the levelized gross plant method will recover costs in equal (or levelized) increments each year of a facility's life.

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from Generation Sources" as one of the six ancillary services.

21 / The judge found that 24 percent of the investment in turbogenerators represents generators and exciter system costs.

22 / Examples of accessory electric equipment are: control cables, power cables, switching equipment, and station grounding. The judge approved AEP's figure of 10 percent for accessory electric equipment, which are treated in 16 separate sub-accounts.

23 / No party filed exceptions to the judge's finding that 0.15 percent is an appropriate allocation factor for other power production investment.

24 / The judge determined that jointly-owned units are appropriately included in the costs used to determine the VAr charge. The jointly-owned generating units here at issue are owned by Columbus Southern Power Company (an AEP affiliate), along with Cincinnati Gas & Electric Company and Dayton Power & Light Company (collectively, the "CCD" units). See 80 FERC at 65,080.

25 / The judge ruled that "CCD" units are appropriately included in the costs used to determine the spinning reserve charge.

26 / The judge determined that AEP should pay 90 percent of its decremental costs for overscheduled energy outside the bandwidth.

Positions of the Parties

AEP proposed a rate for its transmission service based on the levelized gross plant approach described above. AEP argued that it has used this approach consistently for decades. [27] AEP further asserted that it did not propose to switch the rate design methodology for any customers other than a subset of existing and potential transmission customers (i.e., requirements customers).

WVPA, IUCC, Blue Ridge, AMP-Ohio, and trial staff argued against AEP's proposed levelized gross plant approach because:

> (1) under AEP's transmission tariff, transmission customers will not be charged rates that are comparable to AEP's own use of its transmission system, and the rates therefore will discriminate against transmission customers in violation of the Commission's comparability standard;

(2) factors that supported the use of the levelized gross plant approach in cases where it was adopted are absent here; [28] and

> (3) given that AEP's system is composed of facilities with varying levels of depreciation, and the levelized gross plant method does not adjust for such depreciation, the levelized gross plant approach would produce excessive revenues for AEP.

Initial Decision

The judge found that AEP's proposed levelized gross plant methodology of calculating transmission rates results in a switch from the non-levelized net plant methodology for its requirements customers, as well as its retail customers. The judge found that, as a result of this switch,

> AEP's requirements customers (as well as retail customers who may switch to transmission service) will be paying depreciation a second time leading to an overrecovery of AEP's costs. [80 FERC at 65,052.]

The judge also found that AEP did not demonstrate that its proposal meets the Commission's comparability standard as set forth in the Commission's Transmission

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27 / AEP asserts that, historically, many of its interchange service rates were developed based on the levelized gross plant approach. See Ex. A-101.

28 / For example, in Southern California Edison Company, Opinion No. 341, 50 FERC ¶ 61,138 at 61,412 (1990) (SoCal Edison), and Jersey Central Power & Light Company, et al., 38 FERC ¶ 61,275 at 61,927 (1987) (Jersey Central), the company historically had used the levelized approach.

Pricing Policy Statement. [29] In this regard, the judge explained that AEP uses a non-levelized net plant approach for its native load customers while proposing a levelized gross plant approach for non-native load customers. He concluded that,

> [b]ecause AEP's open access tariff does not offer third parties access on the same or comparable basis [as AEP's use of its system], AEP's levelized approach violates the Commission's comparability standard. [80 FERC at 65,053.]

Moreover, the judge found that Commission precedent does not support AEP's proposal to use the levelized gross plant method for transmission service. In particular, the judge noted that AEP's citations to SoCal Edison and Jersey Central are inapposite because the circumstances in those cases are distinguishable from those present here, where AEP is proposing to switch depreciation methods after nearly one-third of AEP's transmission system already has been depreciated without making adjustments to prevent overrecoveries. The judge found the non-levelized net plant methodology appropriate to design rates for AEP's wholesale transmission service.

Exceptions

AEP filed an exception to the judge's rejection of its proposed levelized gross plant transmission rate design. AEP claims that the judge erred in failing to recognize that: (1) the Commission has previously found that the gross plant and net plant methods recover identical costs over the lives of the assets, and the rate differences between the two methods is simply the result of a timing difference in cost recovery; (2) AEP was not proposing a "change" in its rate design method; (3) AEP's use of the levelized method will not result in an overrecovery of its revenue requirement; and (4) comparability does not require use of the net plant methodology.

Blue Ridge, AI, WVPA, and trial staff filed briefs opposing AEP's exception on this issue.

Discussion

We deny AEP's exception, and affirm the judge's rejection of AEP's proposed switch to a levelized gross plant rate design. While reasonable results can be produced using either levelized or non-levelized rate methods, depending on the circumstances, see, e.g., KU, 85 FERC at 62,103-05, here we find that, based on the record before us

29 / Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, FERC Stats. & Regs. ¶ 31,005 at 31,141-44 (1994), order on reconsideration, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement).

and the circumstances presented in this case, the use of a levelized gross plant rate design by AEP would not produce a just and reasonable result. Specifically, we note that AIW and trial staff witnesses testified that this switch would result in an overrecovery of costs by allowing AEP to recover anew depreciation expense that it has already recovered. See, e.g., Exs. AIW-11 at 24-31; AIW-17; S-71 through S-84. [30] We are not convinced by AEP's opposing arguments on this issue (e.g., AEP did not provide any studies demonstrating that there would not be higher rates if the levelized method is adopted, and AEP did not substantiate its claims that it will be adding new transmission plant in the future). See Exs. A-53 at 4 and A-100 at 7.

AEP relies on our order in SoCal Edison in support of its use of a levelized gross plant rate design because AEP has historically provided under certain circumstances long-term stand-alone transmission service under levelized rates, a circumstance that AEP states persuaded the Commission to allow requirements customers to be switched to a levelized rate in SoCal Edison. We reject AEP's argument. As we explained in Consumers Energy Company, 85 FERC ¶ 61,100 at 61,366-67 (1998) (Consumers Energy), the approach we took in SoCal Edison is no longer appropriate. We believe that the concerns that led to our decisions in Consumers Energy, and also in KU, 85 FERC at 62,104- 05, dictate that we no longer follow SoCal Edison.

As we found in KU, and restated in Allegheny Power Service Corp., 85 FERC ¶ 61,275 at 62,117 (1998) (APS), where a utility proposes to switch from a non-levelized net plant rate design method, "[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method." 85 FERC at 62,103- 05. Just as in KU and APS, AEP has not persuaded us here that the switch in current bundled requirements service is appropriate in the circumstances of this case because: (1) AEP's system is composed of facilities with varying levels of depreciation and (2) AEP's proposed levelized gross plant method does not account for such variations. [31]

Based on the foregoing, we reject AEP's proposal to develop its transmission tariff rate using a levelized gross plant method, and we will require AEP to recalculate its tariff rates based on a non-levelized net plant method.

As we stated in Consumers Energy, 85 FERC at 61,367, "[i]t is not our intention to prohibit the use of the levelized approach in every instance. As noted at the outset, the Commission believes that a levelized methodology may produce just and

30 / AIW and trial staff claimed that AEP's proposed switch in methods would increase the transmission revenue requirement by $44.5 and $61.2 million, respectively. See Joint Statement of Issues at 3; and Exs. S-72 and S-74.

31 / The judge's third reason (that AEP's proposed transmission tariff does not offer third parties access to its transmission system on a comparable basis to AEP's use of its own system) is no longer applicable.

reasonable rates under different circumstances." Here, AEP has not persuaded us that its proposed change in approach is appropriate in the circumstances of this case.

2. **Definition of Investment Base**

a. Transmission/Subtransmission "Distribution Use Facilities" Exclusions

Positions of the Parties

AEP asserted that its transmission system is operated on a fully-integrated basis and therefore it included in rate base all of its facilities classified as transmission. A secondary issue involves customer-owned facilities, and AEP did not give a credit for any customer-owned facilities.

AIW [32] opposed this treatment, arguing that customer-owned facilities with comparable functions to AEP's facilities should be considered part of the grid, and that customers with such comparable facilities should receive credits for their own facilities that function in the same manner as AEP's facilities to integrate loads and resources. AIW claimed that AEP's proposal misdefines the transmission grid for purposes of recognizing which facilities will be deemed part of the transmission grid, and for purposes of establishing a rate for the use of the transmission owners' facilities. AIW argued that the Commission must define the grid in one of two ways, and that under either definition AEP's approach here must be rejected. First, AIW asserted that the Commission could define the grid broadly to include all facilities that are actually used to provide service under AEP's tariff. [33] Alternatively, AIW stated that the Commission could adopt a narrow definition of the grid that encompasses only the backbone transmission facilities that are necessary to carry any party's power from a delivery point to a receipt point on bulk transmission facilities. AIW contended that if this definition is adopted, some facilities that AEP includes in its rate base should be removed.

AEP and trial staff argued that the costs of all transmission facilities in both the

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32 / Earlier in this proceeding, joint testimony was presented by AMP-Ohio, IMPA, and WVPA. The judge referred to them collectively as "AIW." 80 FERC at 65,048. The judge, in the Initial Decision uses this same abbreviation to refer to AMP-Ohio and IMPA. To clarify when WVPA is not being referred to, we will refer to AMP-Ohio and IMPA together as "AI" and will use "AIW" when referring collectively to AMP- Ohio, IMPA, and WVPA.

33 / AIW contended that this definition of the grid would better serve the goal of creating workable competitive power supply markets by eliminating discriminatory transmission pricing and encouraging all transmission owners to participate in regional transmission grids.

network and point-to-point tariff should be "rolled-in" in developing the tariff rates. [34]

AEP and trial staff contended that AIW is attempting to insert its claims for a credit for customer-owned facilities into the issue of what is AEP's appropriate rate base for transmission. AEP and trial staff asserted that the issue of what facilities AEP should include in its rate base is different from the issue of what customer facilities are entitled to a credit. Both AEP and trial staff supported the rolled-in approach and argued that the question of credits for customer-owned facilities should not be addressed in this proceeding.

Initial Decision

The judge found that AIW's comparability and other arguments "should be appropriately advanced in a different proceeding." 80 FERC at 65,055. He also rejected arguments by AIW that certain AEP facilities should be eliminated from transmission rate base because they do not serve a network function. Based on these findings, the judge concluded that AEP's rolled-in approach should be adopted.

Exceptions

AI argued on exceptions that, under Order Nos. 888 and 888- A, the standard for inclusion of transmission facilities in rate base is the same standard as for inclusion of customer-owned facilities. AI Brief on Exceptions at 10. That is,

> the Transmission Provider must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. [Id. at 9.]

AI claims that the Initial Decision failed to comply with this standard because it failed to explicitly identify what AEP transmission facilities are providing transmission service to its power and transmission customers and it failed to identify what customer-owned facilities are eligible for credits.

AI further argues that the Commission should provide an "advisory opinion" on the issue of credits for customer-owned facilities. AI Brief on Exceptions at 23-36.

With regard to AI's first point, while AEP agrees that any facilities that are not used and useful in providing transmission service should be excluded from rate base, it maintains that all of the facilities included in its rate base meet that test and are thus

34 / Rolled-in transmission rates are based on the costs of the entire transmission system and reflect the fact that, when there is an integrated system, all of the facilities in the system are deemed to contribute to each use of the system.

properly includable. AEP Brief Opposing Exceptions at 7-8.

Regarding AI's second point, AEP argues that the judge correctly found that this issue is not properly before the Commission in this case. AEP contends that this is confirmed by explicit language in Order No. 888, where the Commission stated that "cost credits related to customer-owned facilities . . . are more appropriately addressed on a case-by-case basis where individual claims for credits may be evaluated against a specific set of facts." Id. at 5, citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743. AEP and trial staff contend that the Commission does not have before it any specific claim for credits for customer-owned facilities and therefore cannot evaluate such a request.

Trial staff also argues that the judge correctly found that the issue of customer credits should be treated when a service agreement is negotiated, and that this issue is beyond the scope of this proceeding.

Discussion

We affirm the judge's finding on this issue with regard to AI's first point. In Kentucky Power Company and Ohio Power Company, 64 FERC ¶ 61,112 at 61,923 (1993) (Kentucky & Ohio), we stated, "[u]nder our pricing policy, it is proper for AEP companies to develop their rates on the basis of a rolled-in, system average for all grid facilities they use for transmission, not just the lines that are at delivery voltage." Accordingly, we agree with AEP's rolled-in approach to rate base and we reject AI's contention that these facilities must be more explicitly identified.

As to AI's second point, its arguments here are the same as those raised to the judge by AIW regarding its eligibility for credits for customer-owned facilities, and we do not find these claims persuasive. As we stated in Order Nos. 888 and 888-A, and in other recent orders, the question of credits for customer- owned facilities is best resolved on a fact-specific, case-by- case basis. [35] As noted by AEP and trial staff, AI identified customer-owned facilities in this proceeding, but did not offer any support to justify a credit for such facilities. Thus, we affirm the judge's findings to accept AEP's rate base without any adjustment for customer credits.

b. Accumulated Deferred Income Taxes - Rockport 2 Plant Sale/Leaseback

Background information explaining this issue was presented in the Initial Decision, where the judge stated that:

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35 / See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743; Order No. 888-A, FERC Stats. & Regs. ¶ 31,049 at 30,271; and Allegheny Power Systems, 80 FERC ¶ 61,143 at 61,539 (1997).

> AEP's Rockport 2 plant was sold in 1989 for $1.7 billion and leased back for an initial term of 33 years. The gain from the sale of the plant was deferred and is being amortized, with the related taxes, over the term of the lease. AEP functionalized Accumulated Deferred Income Taxes
>
> (ADIT) based on a gross plant allocator. AEP took all of its company-wide ADIT and assigned a portion of them to the transmission function based on a fraction with plant in service related to transmission in the numerator and total plant in service in the denominator. ADIT is used to reduce the investment base for purposes of setting a transmission rate. [80 FERC at 65,055, footnote omitted.]

Positions of the Parties

AIW asserted that it is inequitable and contrary to Commission precedent to include in transmission rate base those costs related to the ADIT associated with the Rockport 2 plant sale/leaseback (Account No. 190), [36] but not credit transmission customers with any offsetting gains related to that same sale/leaseback. [37] Consequently, AIW proposed adjusting the functionalization of ADIT to remove ADIT relating to the Rockport 2 plant sale/leaseback. AIW claimed that the Commission previously addressed the proper ratemaking treatment of the costs and gains associated with the Rockport 2 plant sale/leaseback in Blue Ridge, where the Commission held that "ratepayers . . . are entitled to . . . the entire benefit of the sale/leaseback." 57 FERC at 61,373.

AEP's witness stated that AIW's proposed adjustment is a piecemeal approach and that, if ADIT was uniformly removed from all transmission plant, this would increase transmission plant in rate base by more than $33 million. AEP is quite willing to make this adjustment.

Trial staff agreed with AEP that AIW's proposal should be rejected because it is piecemeal. Trial staff claimed that AIW chose one item (the Rockport 2 plant sale/leaseback) and directly assigned that item to generation, and then used the plant ratio fraction for everything else. Trial staff asserts that this approach is selective and unfair. Trial staff supports AEP's original calculation.

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36 / Account No. 190 is a rate base addition; thus, by reducing the costs from this account that are included in rate base, the transmission customers' rates will be lowered. See Exs. AIW-1 at 16-17 and AIW-4.

37 / See AI Brief on Exceptions at 36-39, citing Blue Ridge Power Agency, et al. v. Appalachian Power Company, 57 FERC ¶ 61,100 at 61,373 (1991) (Blue Ridge).

Initial Decision

The judge found that, notwithstanding AIW's arguments to the contrary, Blue Ridge is inapposite here. In Blue Ridge, the Commission held that ratepayers are entitled to the gain from the Rockport sale/leaseback and that the shareholders are not. The issue in that proceeding did not involve ADITs. Conversely, in this proceeding, the issue is the allocation of ADITs among groups of ratepayers. Thus, the judge found that Blue Ridge does not support AIW's position. 80 FERC at 65,055.

Exceptions

AI filed exceptions to the Initial Decision where it raised arguments similar to those raised by AIW before the judge.

AEP and trial staff opposed AI's exception and asserted similar arguments to those they had advanced before the judge.

Discussion

We agree with the judge that AI's reliance on Blue Ridge is misplaced here. In Blue Ridge, we addressed whether ratepayers or shareholders should receive the gain on the Rockport 2 sale/leaseback, 57 FERC at 61,373, while here the issue concerns the proper allocation of ADITs between different groups of ratepayers (i.e., transmission vs. requirements customers). We find that AI is proposing a piecemeal approach that improperly focuses on a change to only one component of ADIT. AI has failed to sponsor an alternative allocation method for ADITs. Thus, we deny AI's exception and affirm the Initial Decision.

c. Generator Step-Up (GSU) Transformers

A GSU transformer is an electrical device that transforms power from a lower voltage to a higher voltage. The GSU transformers in question in this proceeding are those which step- up voltages at the generation level to higher voltages at the transmission level.

Positions of the Parties

AEP maintained that GSUs should be included in transmission rates because they perform a transmission function. AEP also argued that the inclusion of GSUs in transmission rate base is supported by Commission precedent. [38]

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38 / AEP cited Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 at 61,352 (1988).

AI, WVPA, Blue Ridge, and trial staff argued that part of the function of GSUs is production-related and that AEP should not charge its transmission-only customers production-related costs. These participants also argued that Commission decisions supporting inclusion of GSUs in transmission rate base pre-date Order No. 888 where the Commission required utilities to offer unbundled open access transmission service. Thus, these participants argued that the cost of GSUs should be excluded from AEP's transmission rates.

Initial Decision

The judge approved AEP's proposal to continue recovering the costs of its GSUs through its transmission tariff rates. The judge found (80 FERC at 65,056-57) that this proposal was supported by Commission precedent that provides that the purpose of these facilities is to transform, or step-up, generation for the purpose of transmitting power "in bulk with less loss and at less cost . . . ." [39] While acknowledging that the precedent he relied on was from the "pre-unbundling" era, the judge nevertheless found it to be on point because, as in the instant case, it involved transmission-only service. The judge further found that trial staff and intervenors failed to counter AEP's assertion that its classification is in accord with the Uniform System of Accounts. 80 FERC at 65,057.

Exceptions

AI, Blue Ridge, WVPA, and trial staff filed exceptions to the Initial Decision raising arguments similar to those they raised at hearing.

AEP opposed each of these exceptions.

Discussion

In the past, the Commission functionalized a utility's entire cost of GSU transformers as transmission-related and allowed the utility to recover these costs through its rolled-in transmission rate. However, in KU we decided to reverse our policy in light of the Commission's unbundling of transmission and wholesale generation services in Order No. 888. As we stated in KU, given our actions in Order No. 888,

> we believe it is appropriate to reexamine our policy on the functionalization and the recovery of costs associated with GSUs to ensure that unbundled services customers are paying only their appropriate share of the cost of services which they use. [85 FERC at 62,111.]

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39 / The judge cited Minnesota Power & Light Company, Opinion No. 12, 3 FERC ¶ 61,045 at 61,137 (1978), among other cases, for this proposition.

Our reexamination of GSU costs in KU persuaded us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates. Those same findings are applicable here. We therefore reverse the Initial Decision to reflect our revised policy on the recovery of GSU costs, as more fully articulated in KU.

3. **Return on Equity**

After the paper hearing, the parties to this proceeding filed a Stipulation and Agreement (Stipulation) resolving the overall rate of return.[40] Ex. Jt-3. The parties agreed that the overall rate of return to be used to calculate transmission rates in this proceeding would be 9.33 percent. Id. The judge did not rule on this issue; he neither accepted nor rejected the Stipulation. We accept the stipulated rate of return for the following reasons: (1) it does not exceed the upper bound of the ranges of reasonableness advocated by AEP and trial staff; (2) our analysis indicates that the stipulated rate of return is sufficient to assure confidence in the financial integrity of the company, to allow AEP to attract capital, and to provide investors with an adequate return; and (3) no party filed exceptions to it. Thus, we find that the stipulated overall rate of return is just and reasonable.[41]

4. **Revenue Credits v. Demand Divisor Increase**

There are two basic "off-system" ratemaking treatments: cost allocation and revenue credit. Cost allocation treats the transaction as part of the system load, with a portion of the system costs allocated to the off-system sale. Under this method, the demand divisor is increased to include the off-system transaction. Revenue crediting does not allocate costs to the off-system sale. Rather, on-system customers receive a credit for the revenues associated with the off-system sales. Thus, the off-system sale is not included in the demand divisor.

Positions of the Parties

As noted by the judge, "[t]his issue concerns whether AEP should increase its non-firm rate divisor to reflect full transmission system capability, which would make revenue crediting for non-firm rates unnecessary." 80 FERC at 65,060.

AEP advocated reflecting the demand of multi-year point-to- point transmission service in the demand divisor, while crediting other transmission revenues against its

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40 / The signatories of the stipulation are AEP, AMP-Ohio, IMPA, Blue Ridge, WVPA, Indiana Office of Utility Consumer Counselor, and trial staff.

41 / See Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 693 (1923); FPC v. Hope Natural Gas Company, 320 U.S. 591, 605 (1944).

cost-of-service. Specifically, AEP proposes credits to the cost-of-service for revenues from transmission of electricity by others, interruptible service revenues and system sales revenues related to the transmission function.

AIW opposed revenue crediting, and instead argued that, with respect to non-firm rates, the appropriate cost divisor is transmission system capability as measured by AEP's generating capacity plus firm, long-term transactions. AIW asserted that the use of revenue credits to offset the non-firm revenue requirement is inappropriate because revenues from the use of excess capacity of the transmission system are already accounted for in the demand divisor.

Trial staff opposed both the AEP and AIW approaches, and argued that AEP should include all firm transmission service demand in the demand divisor, and credit only revenues from non- firm transmission service against the cost of service, as this would be consistent with Commission's precedent. Specifically, trial staff contended that its approach is consistent with Order No. 888 wherein the Commission stated that it would allow point- to-point firm transmission rates to be based on adjusted monthly system peak loads, which it defined as:

> the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with all firm point-to-point service customers plus the monthly contract demand reservations for all firm point-to-point service. [[42]]

Initial Decision

The judge found that trial staff's proposed method was supported by the provisions of Order No. 888. He therefore adopted trial staff's proposal stating that:

> a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of a load for cost allocation and planning purposes. [[43]]

Exceptions

AI filed exceptions to the judge's findings, arguing that the judge failed to address its proposal that the denominator for this service should be set at an amount equal to "AEP's generating capacity plus firm contract demands." AI Brief on Exceptions at 53.

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42 / Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

43 / 80 FERC at 65,061, citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,738.

In essence, AI contends that: (1) the Commission recognizes that most non-firm service is less valuable and should be priced below the level of firm service; and (2) this should be accomplished through the use of a larger divisor, and therefore a lower rate.

AEP and trial staff oppose AI's exception. Trial staff agrees with AI's first contention, but not the second. Trial staff states that where the non-firm rate is a ceiling, or "up- to" rate capped at the firm rate (as here), the Commission has consistently allowed this treatment. Trial staff contends that the use of the same divisor for both non-firm and firm services and capping the non-firm rate at the firm rate is consistent with Commission precedent, the Commission's Pricing Policy Statement, and Order No. 888. [44]

Discussion

We reject AI's argument that the Initial Decision did not squarely address its proposal. As noted by the judge, we resolved this issue in Order No. 888, where we concluded that it is appropriate for non-firm service to be priced using up-to rates with the ceiling rate set at the firm service rate. [45] In addition, we agree with trial staff that AEP should include the demand for all firm transmission service in the demand divisor, and only credit revenues from non-firm transmission against the cost of service. Thus, we conclude that AI's exceptions raise no arguments not already considered and rejected by the judge, and we affirm the findings of the judge on this issue.

5. **Demand Divisor**

This issue involves the development of the demand divisor for firm transmission rates.

Background

Initially, AEP proposed a non-customer-specific firm point- to-point transmission rate based on a 12 CP demand divisor. [46] In our order setting AEP's filing for hearing,

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44 / Trial Staff Brief Opposing Exceptions at 58-60, citing, e.g., Central Maine Power Company, 54 FERC ¶ 61,206 at 61,612 (1991); Transmission Pricing Policy, FERC Stats. & Regs. ¶ 31,005 at 31,137 (1994); and Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

45 / Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44.

46 / 64 FERC at 62,977. Demand allocation determines the charge allocated to a class of customers. Under the 12-month coincident peak method, commonly known as the 12 CP method, demand is allocated by taking the hour of highest usage (the coincident peak) in twelve consecutive months, determining the percentage of peak use by each customer class during each of the twelve months, and averaging the resulting

we summarily rejected AEP's proposal, citing our precedent in Southern Company Services, 61 FERC ¶ 61,339 (1992) (Southern). We gave AEP the option of developing a "customer-specific" rate by allocating AEP's total transmission-related revenue requirement using a customer-specific revenue requirement using those customers' 12 coincident peaks and billing determinants, or to develop a non- customer-specific rate using a 1 CP demand divisor. AEP elected to maintain its non-customer specific approach, but nonetheless filed a request for rehearing, asking us to allow it to use a 12 CP demand divisor in conjunction with a non-customer-specific revenue requirement. We denied rehearing on this issue and directed AEP to use the annual system peak (1 CP) as the demand divisor. 67 FERC at 61,487. AEP complied with the Commission order and filed a 1 CP demand divisor. [47] AEP did not file a petition for review of the Commission's orders.

Positions of the Parties

Notwithstanding that the issue was rejected by summary disposition and was not set for hearing, AEP attempted to preserve and litigate this issue at hearing and continued to advocate a 12 CP demand divisor throughout the proceeding. AEP argued that in Order No. 888 the Commission changed its policy with respect to the use of a 12-CP demand divisor when a tariff allows full flexibility for point-to-point service. AEP contended that its tariff (filed in connection with its offer of settlement and Order No. 888) allows this full flexibility, and the use of a 12 CP demand divisor is thus appropriate. AEP Initial Brief at 26-27.

Initially, trial staff supported AEP's request to use a 12 CP allocator based largely on the reasons given by AEP. Trial staff argued that Commission precedent supports the use of a 12 CP divisor when the average of the 12 monthly peaks to the single peak is more than 84 percent of the single system peak. Trial staff asserted that this average for AEP's system is 89.9 percent. Trial Staff Initial Brief at 49.

AIW argued that the Commission's orders setting this proceeding for hearing summarily dismissed the 12 CP divisor as an issue in this proceeding. Thus, AIW asserted the adoption of a 12 CP rate at this late date would be both unfair and legally impermissible in this proceeding. Blue Ridge and WVPA also argued that the 12 CP v. 1 CP issue is no longer within the scope of this proceeding.

In addition to opposing AEP's 12 CP proposal on procedural grounds, intervenors also opposed the method AEP used to develop its 1 CP divisor. AIW argued that AEP's

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percentages for each customer class. By contrast, the 1 CP method allocates demand
among customer charges based on the annual coincident peak.

47 / AEP proposed a 1 CP demand divisor of 17,753 MW, reflecting its 1992 internal peak minus its interruptible loads and generator direct loads, plus 1,258 MW of firm contract demand. Ex. A-22.

1 CP calculation should be adjusted to include: (1) an additional 329 MW of demand associated with long-term transmission contracts; (2) 890 MW of generator direct loads served by AEP; [48] and (3) the Buckeye Power Cooperative (Buckeye) load as a long-term load. [49]

Blue Ridge and WVPA argued that the peak demand used as the divisor should be 35,000 MW, which is the projection of AEP's transmission system capability. Blue Ridge and WVPA base this argument on a technical paper prepared by an AEP engineer stating that the system was designed to serve an expected load of 35,000 MW. [50] However, if this approach is rejected in favor of using an annual system peak, then alternatively Blue Ridge advocated using AEP's 1993-94 winter peak (25,194 MW). Blue Ridge contended that this peak represents AEP's proven transmission system capability, and is "a more credible proxy for transmission system capability than use of a test year peak exceeded in prior or subsequent years." Blue Ridge Initial Brief at 18.

Initial Decision

The judge noted that the Commission had considered the issue of 1 CP vs. 12 CP in both its hearing order and its order on rehearing in this proceeding, and that the Commission had rejected AEP's proposed use of the 12 CP method in both instances. The judge also found that, while Order No. 888 now allows utilities to use a 12 CP demand divisor in their point-to- point tariffs, it did not mandate the use of this method. Thus, the judge rejected AEP's proposed 12 CP methodology. 80 FERC at 65,066. [51]

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48 / AIW and trial staff argued that another 890 MW should be added to AEP's 1 CP demand divisor to reflect certain generator direct served loads (two specific retail loads, see AEP Brief Opposing Exceptions at 22), because the transmission facilities serving the two specific retail loads are routinely included in AEP's transmission planning and load flow studies. Exs. S-72; AIW-20; and AIW-11 at 39- 43.

49 / AEP opposed including in the demand divisor firm transmission service AEP provides to Buckeye. AEP acknowledged that this is a resource/load integration type transaction, but it then argued that this transmission should not be included in the demand divisor because resource/load integration type service is not offered under its open access tariff. Ex. AEP-55. AIW argued that AEP's position is no longer valid because AEP is now offering network integration service. Therefore, AIW contended that the Buckeye loads should be included in the demand divisor. Ex. AIW-11 at 38-39. The Buckeye load is 937 MW, which AEP included as load for purposes of a 12 CP divisor.

50 / By comparison, the judge found that the single system peak during the test year was 18,598 MW (80 FERC at 65,064) and AEP's highest system peak occurred in 1993-1994, when total load reached 25,174 MW (80 FERC at 65,065).

51 / The judge did not dispute that AEP may propose a 12 CP methodology in future proceedings, but agreed with AIW that this would require a new section 205 filing.

The judge found the appropriate divisor to be 17,753 MW as calculated by AEP using a 1 CP demand divisor. The judge rejected Blue Ridge's contention that the peak should be based on the 1993-94 winter peak because the proceeding is based on 1992 test year costs.

Exceptions

While supporting the Initial Decision's adoption of a 1 CP approach, Blue Ridge filed exceptions arguing that the judge erred by relying on AEP's test-year peak figures to obtain the demand divisor and by failing to consider alternatives suggested by Blue Ridge and other interveners. In particular, Blue Ridge argues that the judge failed to consider peak loads subsequent to the test year (e.g., the 1993-94 winter peak) as a measure of system capability. Blue Ridge argues that consideration of these loads would yield a demand divisor of 25,194 MW, an amount that Blue Ridge claims represents AEP's proven transmission capability. [52]

AI and WVPA filed exceptions to the Initial Decision reiterating the arguments they made before the judge in support of their proposed 1 CP divisor.

AEP also filed exceptions to the Initial Decision and argues that the Commission is not legally precluded from using a 12 CP divisor, and that the evidence AEP has submitted here supports the use of a 12 CP divisor.

Trial staff filed exceptions to the judge's method of calculating the single peak, arguing that it is inconsistent with both Order No. 888 and the methodology adopted by the judge in the Initial Decision. [53] Trial staff further argues that the rationale underlying the 1 CP figure adopted by the judge is inconsistent with the determinations reached by the judge elsewhere in the Initial Decision. [545454] Trial Staff Brief on Exceptions at 20-24.

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52 / Blue Ridge Brief on Exceptions at 12-15. This figure is the highest monthly peak demand AEP had reached as of the date Blue Ridge filed its initial testimony.

53 / Trial staff's calculation started with AEP's monthly firm peak load, then subtracted the monthly coincident peaks associated with all firm point-to-point customers and added the monthly contract demand reservations for firm point-to- point service. This results in a 1 CP demand divisor of 19,537 MW.

54 / For example, in his ruling on the treatment of revenue credits, the judge ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

54 / For example, in his ruling on the treatment of revenue credits, the judge

However, trial staff supported the judge's determination that AEP should be precluded, for procedural reasons, from use of the 12 CP divisor in this proceeding. Trial Staff Brief Opposing Exceptions at 29-30.

AEP, AI, WVPA, Blue Ridge, and trial staff filed briefs opposing exceptions.

Discussion

We find AEP's efforts to preserve and litigate this issue at hearing unavailing. We therefore reject AEP's exception advocating the use of a 12 CP divisor, and we affirm the judge's adoption of a 1 CP divisor in this proceeding.

We summarily rejected AEP's 12 CP proposal in both our initial hearing order (64 FERC at 62,976-77) and in our order on rehearing (67 FERC at 61,487).[55] By summary disposition, we made a final determination resolving this issue and removing the issue from further consideration in this proceeding. Any timely challenge to this final determination would have had to have been made in a petition for review to the U.S. Court of Appeals, seeking appeal of this determination. However, no such appeal was filed.

Moreover, to allow AEP to pursue this issue now would be unfair to Intervenors who, based on our prior orders, quite properly understood that this issue was no longer within the scope of this proceeding.[56] Thus, regardless of any subsequent changes in Commission policy, it would be unfair and prejudicial to the other parties -- and a violation of their due process rights -- for us to consider anew the merits of AEP's 12 CP proposal at this late stage of the proceeding.[57]

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ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

54 / For example, in his ruling on the treatment of revenue credits, the judge ruled that the contract demands of all firm customers should be included in the demand divisor, 80 FERC at 65,060-61, and in his ruling on the annual demand divisor, he adopted AEP's figure for the 1 CP, which does not include all long-term firm transactions, id. at 65,066.

55 / The hearing order also gave AEP guidance on what cost support should be submitted in a new filing seeking the use of a 12 CP demand divisor. 64 FERC at 62,977.

56 / See AI Initial Brief at 56-57; AI Brief Opposing Exceptions at 31-33; WVPA Brief Opposing Exceptions at 15-16; and Blue Ridge Brief Opposing Exceptions at 12-14,

While AEP correctly notes that in Order No. 888 we revised the policy we earlier had enunciated in Southern (and which we relied on in our earlier orders to dismiss AEP's 12 CP proposal), AEP fails to consider two important factors that relate to this change in policy. First, as noted by the judge, 80 FERC at 65,066, in Order No. 888 we did not give transmission providers an automatic and immediate right to develop their rates using a 12 CP divisor; rather, we stated that commencing with the ordered improvements in the tariff services we would no longer summarily reject filings on this basis but would instead allow transmission providers seeking a 12 CP divisor to make a filing with the Commission supporting such a proposal and to pursue this at hearing. [58] Following the Commission's issuance of Order No. 888, AEP had the option of filing a new section 205 rate case, seeking Commission approval to use a 12 CP demand divisor in conjunction with non-customer-specific rates. It chose not to do so.

AEP instead chose to continue to raise this issue in the instant proceeding (based on our issuance of Order No. 888), even though Order No. 888 was issued nearly three years after the Commission's hearing order removing the 12 CP issue from this proceeding. However, as discussed above, due to the finality of our decision on this issue in this proceeding, we reject this effort. For these reasons, we reject AEP's proposal to allow it to develop its point-to-point transmission rates using a 12 CP divisor.

AEP advocated a 1 CP demand divisor of 17,753 MW, which was adopted by the judge, but, as pointed out by AIW and trial staff, this number is inconsistent with other determinations in the Initial Decision. We reject 17,753 MW as 1 CP demand divisor. Trial staff proposed a 1 CP demand divisor of 19,537 MW, which is derived by adding the following: (1) 16,495 MW - adjusted internal peak load; [59] (2) 799 MW - for firm contract demand; (3) 1,304 MW - for firm transmission for others; (4) 890 MW - for two specific retail loads; [60] and (5) 49 MW - for the Indianapolis P&L sale. We adopt trial staff's proposed 1 CP demand divisor with one modification. [61] We affirmed the judge's

57 / This is true regardless of the judge's decision to receive into evidence AEP testimony in support of a 12 CP proposal. It is within the purview of the Commission, not of the judge, to define the scope of a proceeding and the Commission already had reached a determination on the 12 CP issue when it set this case for hearing before a judge.

58 / Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,737-38. See also Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,263.

59 / See Exhibit A-24.

60 / Trial staff claimed that the Buckeye load of 937 MW is included in the 1,304 MW. Trial Staff Brief Opposing Exceptions at 34.

61 / We start with AEP's proposed internal peak load of 16,495 MW (item 1). We add to this trial staff's proposed adjustments for long-term firm transmission service (items 2 and 3) and 890 MW (item 4) for two specific retail loads (as argued by AIW and

decision to treat the Indianapolis P&L sale as a revenue credit; therefore, we modify trial staff's proposal by adopting 19,488 MW (19,537 MW minus 49 MW) as the 1 CP demand divisor.

6. Appalachian Pricing Method Issues

Appalachian pricing is a rate design method approved by the Commission for short-term service expected to be taken only during peak periods. The hourly charge is developed assuming usage of 16 hours a day, five days a week, 52 weeks a year (i.e., 4,160 hours per year) in contrast to the 8,760 total hours in a year. [62] Under this rate design, 100 percent of the annual cost of service is equally distributed to each of the 52 weeks in a year; 100 percent of the weekly cost is equally distributed to five of the seven days in a week (Saturday and Sunday are off- peak days and are excluded); and 100 percent of the daily (weekday) cost is equally distributed to 16 of the 24 hours in a day (the other 8 hours are off-peak hours and are excluded). [63] In addition, to prevent over-recovery, this rate is accompanied by a proviso that no customer can be charged more than the equivalent daily or weekly rate (e.g., charges for hourly usage are capped at the equivalent daily rate). 39 FERC at 61,964-65. The Appalachian rate design method was established on the theory that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. Id. at 61,965.

Positions of the Parties

AEP proposed to use the Appalachian method for developing its hourly and daily transmission rates for short-term transmission service. Trial staff generally supported AEP, arguing that it is appropriate for AEP to develop its on-peak hourly and daily rates using the Appalachian method, but only if it also offers off-peak service with hourly and daily rates developed using seven days for daily service and 8,760 hours for hourly service.

AIW and Blue Ridge contended that the Appalachian method should be abandoned and a pricing method that encourages economically efficient transactions should be used instead. They further contended that trial staff's approach is not sufficient because the only reasonable method for time-differentiation is to reduce the

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trial staff). We subtract 49 MW (item 5), based on our findings on the Indianapolis P&L sale.

62 / See Appalachian Power Company, 39 FERC ¶ 61,296 (1987) (Appalachian).

63 / The use of a five day week, 16 hour day and 52 week year results in 4,160 peak hours in a year.

off-peak rates, not to raise the on-peak rate even further above the cost of service (which they claim would be the result of trial staff's proposal). AIW argued that AEP should use system capacity as the denominator to calculate the non-firm rate because they contended that system capacity represents a conservative measure of AEP's actual capability. In addition, an AIW witness proposed a six day divisor for daily service.

Initial Decision

The judge found trial staff's peak/off-peak proposal to be a reasonable adjustment to the Appalachian method for this proceeding. He stated:

> Staff's proposal achieves the Commission goal of recovering [costs] from those who take service at the time of the peak 4,160 hours while off-peak rates are based upon a distribution of annual costs over all 8,760 hours. [80 FERC at 65,069.]

Thus, the judge reasoned, customers using short-term transmission service during off-peak hours do not constrict the system during the critical load period and should pay less than they would under the Appalachian method. Therefore, the judge found that trial staff's proposal would result in just and reasonable rates, and he adopted it. Id.

Exceptions

AI and WVPA claim that the Initial Decision is internally inconsistent because on the one hand it rejects using the Appalachian method in developing hourly rates for short-term transmission system sales and buy/sell transactions, while on the other hand it approves the Appalachian method for non-firm transmission rates. [64] AI and WVPA argue that the Commission should find that an 8,760 hour year should be used in determining on-peak non-firm hourly rates for both revenue credits and unit rates in the Open Access Tariff. [65] AEP and trial staff oppose AI's and WVPA's exceptions.

Discussion

The theory behind Appalachian pricing is that a customer who uses the transmission system for 16 peak hours in a day should pay the same contribution to the fixed costs of the transmission system as a customer who has reserved capacity on a daily basis. 39 FERC at 61,965. We have previously determined that Appalachian pricing is not warranted where it has not been shown that 16 hours is a good proxy for

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64 / AI and WVPA ask us to compare the judge's finding basing credits for buy/sell and off-system sales on an 8,760 hour test year (which we affirmed summarily, see note 18 supra) to his ruling using a 4,160 hour year for determining the on-peak non-firm transmission rate (80 FERC at 65,068-69).

65 / WVPA Brief on Exceptions at 22; AI Brief on Exceptions at 58-60.

total daily usage.

We disagree with AI's and WVPA's contention that the Initial Decision is internally inconsistent because it uses the Appalachian method for non-firm transmission rates but not for certain revenue credits. AI and WVPA are referring to bundled non-firm, short-term system power sales transactions that AEP engaged in during the 1992 test year. AEP reflected a credit of $25.8 million for the transmission component of the non-firm short-term system power sales to which AI refers. These transactions occurred prior to open access. Therefore, AEP did not separately calculate a transmission component for these bundled power sales, but instead estimated a transmission revenue credit, thereby reducing the cost of service by the estimated transmission credit. The Initial Decision approved the estimate as reasonable, 80 FERC at 65,062, and we affirm this finding for the reasons stated by the judge. Intervenors have not contended that AEP's proposal would result in unjust and unreasonable rates or in an overrecovery of costs. Instead, they argue it is inconsistent with other findings made in the Initial Decision. As mentioned above, we disagree. Therefore, there is no impediment to accepting AEP's proposal and rejecting the arguments of AI and WVPA.

Accordingly, we affirm the finding of the judge on this issue.

B. ANCILLARY SERVICES RATES

1. Levelized Gross Plant Method v. Non-Levelized Net Plant Method

Positions of the Parties

AEP recommended using the levelized gross plant methodology to determine rates for ancillary service. AEP explained that its reasoning for using this methodology is the same as discussed for base transmission rates. However, AEP believed that where services are available from third parties, rates should be market-based rather than cost-based. AEP Initial Brief at 32.

AIW argued that ancillary services rates should be developed using non-levelized net plant methodology.

Trial staff argued that three of the six ancillary services -- Regulation and Frequency Response Service, Operating Reserve - Spinning Reserve Service, and Operating Reserve - Supplemental Reserve Service -- are not monopoly services because transmission customers can provide these services and put a downward pressure on the prices offered by AEP. Moreover, trial staff argued that AEP's levelized gross plant rates are "up to" rates that AEP can discount on a non-discriminatory basis. Based on this, trial staff concluded that developing rates for these three ancillary services on a levelized gross plant is not unreasonable.

Initial Decision

The judge found that the non-levelized net plant methodology for developing ancillary services rates is appropriate for the same reasons as discussed with respect to transmission rates.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative and determine that AEP's proposal to price these ancillary services using the levelized gross plant method is reasonable. We have repeatedly approved the use of the levelized gross plant method of pricing as a reasonable approach. Although in this proceeding, as in KU, we have rejected company proposals to use a levelized gross plant method to price transmission tariff rates, this was because these cases involved company proposals to switch pricing methods (from a non-levelized net plant pricing to a levelized gross plant pricing) in mid-stream for what were similar transmission services. It is this switching of methods, and not the levelized gross plant method itself, that we find has led to the development of rates that have not been shown to be just and reasonable. Conversely, here there is no switching of methods involved because these ancillary services are new services that were not previously provided as separate services. This is a key distinction that makes the KU precedent on the pricing of transmission rates inapposite here.

For these reasons, and because no party has shown that the ancillary rates produced by AEP's levelized gross plant method are otherwise unjust, unreasonable or unduly discriminatory, we adopt AEP's pricing approach.

2. **Scheduling, System Control and Dispatch Service**

We agree with the judge that there are no remaining issues involving this ancillary service. 80 FERC at 65,071. Ex. Jt-1 at 21. The per unit rates will be affected by the cost divisor ultimately found just and reasonable, which we find is the same divisor we found proper for the base transmission rate -- 19,488 MW. See section III.A.5 above.

3. **Reactive Supply and Voltage Control (VAr)**

a. Active and Reactive Allocation Factor

Positions of the Parties

AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function." AEP Initial Brief at 37. While both AEP and trial staff generally agreed on the methodology to calculate allocation factor applicable to reactive production, [66] they disagreed on the location at which the reactive capability should be measured. Depending on the measuring point location chosen, costs will be shifted between customers taking transmission service and native load customers. AEP asserted that the name-plate reactive capability at the generator terminals should be used. [67] Trial staff explained that some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs, before it reaches the transmission system. [68] Accordingly, trial staff argued that the Commission should not use the generator's nameplate reactive capability, but instead should use the reactive capability at the GSU terminals available to the transmission system. Ex. S-88. Thus, while AEP proposed a reactive power allocation factor of 21 percent, trial staff recommended only 11.47 percent.

AEP, however, maintained that the GSUs should remain a part of the transmission system. Also, even if GSUs are functionalized to production, AEP argued that despite the reactive power losses associated with auxiliary loads and GSUs, the generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Reply Brief at 43.

Initial Decision

The judge found merit in AEP's argument that there must be enough reactive power remaining at the transmission terminal to provide the voltage control support on the system. Accordingly, he determined that AEP's proposed 21 percent allocation factor for reactive power measured at the generator terminals was just and reasonable. [69]

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66 / The parties agreed to use the formula $MVAr^2/MVA^2$ to determine the allocation factor.

67 / AEP maintains that reactive capability should be measured at generator terminals (the low-voltage side of the GSU), while trial staff maintains that it should be measured at the GSU terminals nearest to the transmission system (the high- voltage side of the GSU).

68 / As noted earlier, trial staff argued that the GSUs should be refunctionalized to production.

Exceptions

Trial staff filed exceptions arguing again that, during the step up of power and energy from the generator terminal voltage to transmission voltage, some of the reactive power produced by the generators actually is consumed by AEP's plant auxiliary loads and by the GSUs. In its exceptions, trial staff reiterates its position that the critical issue here is whether GSUs perform a transmission function or a generation function. Trial staff argues that the judge erroneously determined that the GSUs should be assigned to the transmission function, and that, consequently, the reactive power losses in the GSUs belong to the transmission function. However, trial staff contends that the judge's finding was erroneous. Trial staff states that, in the event the Commission reverses the judge on GSUs, it should adopt the trial staff's reactive power allocation factor of 11.47 percent. Trial Staff Brief on Exceptions at 32-33.

In its Brief Opposing Exceptions, AEP disagrees with trial staff's contention that the functionalization of GSUs to transmission or production is controlling on this issue because the allocation factor is based on capability. AEP argues that, irrespective of the location at which reactive power capability is measured, the generating equipment must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system. AEP Brief Opposing Exceptions at 37-38.

Discussion

We adopt the judge's finding that 21 percent is the appropriate allocation factor to segregate the costs of reactive (VAr) production from those of active (Watt) production. We are not persuaded by trial staff's assertion that the reactive capability of the generators should be reduced by the VArs consumed by GSUs and auxiliary loads before developing an allocation factor. We agree with AEP (and the judge) that the allocation factor should be based on the capability of the generators to produce VArs and that this capability should be measured at the generator terminals. We find merit in AEP's assertion that a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system.[70] See AEP Reply Brief at 43. For these reasons, and for the reasons stated by the judge in the Initial Decision, we affirm the judge's ruling on this issue in the Initial Decision.

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69 / 80 FERC at 65,079. The judge found that the GSUs perform transmission functions. Id. He therefore did not reach trial staff's contentions that relied on the facilities being deemed to perform generation functions.

70 / However, we will require AEP to recalculate the transmission loss factor to exclude real power losses that take place in GSUs.

b. Unrelated O&M Expenses

Positions of the Parties

AEP proposed to include all O&M expenses that are directly and indirectly related to the production of reactive power in its carrying charge rate [71] of 22.1 percent. AEP claimed that its methodology excludes O&M expenses unrelated to reactive power production. Exs. A-28 at 1; and A-95. Trial staff agreed. Trial Staff Reply Brief at 39.

AIW argued that AEP's method will lead to an overrecovery of its O&M expenses because in developing its carrying charge, AEP improperly included costs from O&M accounts that have no direct relation to the production of reactive power. AIW also argued that AEP's method allocates O&M expenses on a different basis than it allocates plant costs related to VAr production. In addition, AIW argued that AEP should remedy the problem by performing an account-by-account analysis of which O&M costs are actually related to the production of reactive power, and that only those costs should be included in the development of the fixed charge rate. Ex. AIW-11 at 58. AIW Initial Brief at 70- 71.

AEP disagreed with AIW's argument that O&M expenses indirectly related to production equipment should be excluded from the development of the carrying charge rate because they do not directly contribute to reactive power production. AEP Initial Brief at 39-40. AEP further stated, "[t]here is no production equipment [that] does not contribute to reactive power production." Ex. A-53 at 43.

Initial Decision

The judge ruled that AIW's method of allocating O&M expenses related to reactive power production is superior to AEP's method because AIW logically assigned O&M expenses to the VAr producing equipment in the same proportion as its investment in such equipment. The judge found that AEP had not justified why O&M expenses related to VAr production should be allocated on a different basis than the plant costs related to VAr production, and he thus rejected AEP's proposal (which would have produced higher rates). The judge found AIW's approach to be reasonable because it provided for a consistent treatment of the plant costs and O&M expenses related to VAr production. The judge also found that AEP's argument (that there is no production equipment that does not contribute to reactive power production) is unavailing because the issue here does not concern the total exclusion of the O&M expenses from the VAr charge, but instead involves the proper allocation of O&M expenses to the VAr charge. However, the judge noted that in accordance with his ruling that the non- levelized net

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71 / Carrying charge is a component of revenue requirements that provides for the return of and on capital invested in plant, taxes, and insurance premiums.

plant method is appropriate for developing ancillary services rates, the issue of allocation of O&M expenses is moot because there will be no carrying charge under the non- levelized method. 80 FERC at 65,081-82.

Exceptions

No party filed exceptions on this issue.

Discussion

In accordance with our ruling approving AEP's use of a levelized gross plant rate design for developing the ancillary services rates, the proper allocation of reactive power O&M expenses is no longer moot. We affirm the judge's finding that AIW's method of allocating reactive power O&M expenses is superior to AEP's method for the reasons stated in the Initial Decision.

4. Operating Reserves (Spinning Reserves/Supplemental Reserves/Regulation and Frequency Response)

a. Pricing for Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service

Positions of the Parties

AEP proposed to allocate the minimum East Central Reliability Council (ECAR) requirement of a 6 percent operating reserve level as follows: 1.5 percent for Regulation and Frequency Response Service; 1.5 percent for Spinning Reserve Service; and 3 percent for Supplemental Reserve Service. AEP Initial Brief at 40-41.

While no party took issue with AEP's allocation of 3 percent for Supplemental Reserve Service, trial staff, AIW, and IUCC disagreed with AEP's method of dividing the 3 percent ECAR minimum Spinning Reserve in equal amounts between Regulation and Frequency Response and Spinning Reserve. [72] Noting that there are no industry guidelines available on this matter, and that AEP failed to provide data to track moment-to-moment variations (which would have enabled the parties to more accurately allocate this 3 percent figure), trial staff developed its own 4-step method based on AEP's hour-to-hour load deviations. In developing its 4-step method, trial staff made four "simplifying assumptions." [73] Using that method, trial staff calculated 1 percent for

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72 / The parties agreed that AEP carries a total of 6 percent of capacity to provide for the following three ancillary services: (1) Regulation and Frequency Response Service, (2) Spinning Reserve Service, and (3) Supplemental Reserve Service.

73 / Trial staff's "simplifying assumptions" are described in Trial Staff's Brief

Regulation and Frequency Response Service and 2 percent for Spinning Reserve Service. [74] AEP opposed trial staff's proposed allocation and methodology, contending that several of the underlying assumptions made by trial staff served to understate the amount of capacity needed for regulation and frequency response service to follow load.

Initial Decision

The judge rejected AEP's criticism of trial staff's approach as conclusory and found that AEP neither provided data to track moment-to-moment variations nor any evidence to support its claim that trial staff's estimate for regulation and frequency response service was understated. The judge also noted that although AEP stated in its Initial Brief that it would discuss this issue in detail in its Reply Brief, AEP's Reply Brief does not even address operating reserves. AEP Initial Brief at 41. The judge then held that until a standard is developed and endorsed by the Commission, trial staff's formula is reliable to calculate the level of Regulation and Frequency Response Service for AEP. Thus, the judge allowed AEP to recover 1 percent of its production costs for the provision of Regulation and Frequency Response Service and 2 percent for the provision of Spinning Reserve Service.

Exceptions

AEP filed exceptions to the judge's decision and argues that trial staff's four "simplifying assumptions" are not representative of actual AEP operating conditions. AEP asserts that, in addition to a Spinning Reserve requirement of three percent, an additional three percent is required for Regulation and Frequency Response Service merely to follow the load trend (for a total of six percent). Nevertheless, AEP proposes only to recover a Regulation and Frequency Response Reserve of 1.5 percent and a Spinning Reserve of 1.5 percent (for a total of three percent). AEP Brief on Exceptions at 34.

Trial staff argues that a proper breakdown between Regulation and Frequency Response Service and Spinning Reserve Service is important because a customer has fewer options available for obtaining Regulation and Frequency Response Service. Trial staff points out that while both services can be obtained from a source other than the transmission provider, Regulation and Frequency Response Service can only be provided by generators that are operated under Automatic Generation Control or some NERC-approved method that enables the generator to instantaneously follow load, thus creating technical limitations on a purchaser's ability to obtain this service from a provider other than the transmission provider. Trial staff argues that such limitations do not exist for competitively obtaining Spinning Reserve Service. Trial Staff Brief

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Opposing Exceptions at 40.

74 / Trial Staff Initial Brief at 65. AI Initial Brief at 71. IUCC Initial Brief at 30-31.

Opposing Exceptions at 36-43.

Discussion

We reverse the judge and, based on the evidence presented in the record, approve AEP's proposal that the pricing of Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service should be allocated based on 1.5 percent, 1.5 percent, and 3.0 percent of production costs, respectively. As noted above, there were no industry guidelines for the pricing of these ancillary services at the time this case was litigated, and thus AEP attempted to allocate the ECAR minimum requirement among these services. No participant has demonstrated that AEP's proposal is unreasonable, and indeed, the fact that the different approaches used by AEP and trial staff each produces a combined rate of 3.0 percent for Regulation and Frequency Response Service and Spinning Reserve Service corroborates the reasonableness of AEP's overall end result, based on the evidence presented in the record. AEP is only required to show that its proposal is reasonable; not that its proposal is the only reasonable result on this record, or that its proposal is superior to all other proposals. [75] For these reasons, we adopt AEP's proposal.

b. Other Production Facilities

Positions of the Parties

AEP did not seek to include GSUs in developing its ancillary services rate because it included GSUs in developing its base transmission rate. However, trial staff argued that GSUs are used in providing generation-based ancillary services to transmission customers, and therefore, the cost of GSUs should be included in the rate for those ancillary services. [76] Trial Staff Initial Brief at 72-73. AIW opposed trial staff's proposal to include GSUs in the charges for AEP's generation-based ancillary services, arguing that these services are provided at the generation bus and do not require the use of GSUs. AI Initial Brief at 71-72. Ex. AIW-46 at 20.

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75 / See City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984), cert. denied, 467 U.S. 917 (1984) (utility need establish only that its proposed rate design is reasonable, not that it is superior to all alternatives); MCI Telecommunications Inc. v. FCC, 627 F.2d 322, 340 (D.C. Cir. 1980) (the standard of "just and reasonable" does not require that the rates be perfect); New England Power Company, Opinion No. 352-A, 54 FERC ¶ 61,055 at 61,198, aff'd sub nom. Town of Norwood, Mass. v. FERC, 962 F.2d 20 (D.C. Cir. 1992) (a proposed rate design need only be shown to be just and reasonable, not superior to all alternatives).

76 / The generation-based ancillary services referred to by trial staff are: (1) Reactive Supply and Voltage Control; (2) Regulation and Frequency Response Reserve Service; (3) Operating Reserve - Spinning Reserve Service; and (4) Operating Reserve - Supplemental Reserve Service.

Initial Decision

The judge determined that, consistent with his finding that GSUs perform a transmission function, GSU costs already are allocated to transmission customers. He held, therefore, that GSUs should not be included as a cost for any of the ancillary services.

Discussion

As discussed above, in section III.A.2.c, our reexamination of GSU costs in KU persuaded us that the costs of a GSU transformer should be directly assigned to its related generating unit, not rolled into transmission rates. In KU, we stated that:

> GSUs also perform an important function in the provision of a new category of services we identified in Order No. 888, ancillary services (e.g., Operating Reserve, Regulation and Frequency Response Service, Reactive Supply and Voltage Control). Ancillary services supplied from generation resources cannot be provided without reliance upon GSUs, regardless of where power is coming from or going to.
>
> In short, we find that GSUs are used in the provision of both generation and ancillary services, and that the costs of these facilities should be charged to the customers using these facilities. [85 FERC at 62,112].

Therefore, we find that it is appropriate to include the cost of GSUs in developing rates for all ancillary services that are supplied from generation sources. Accordingly, we reverse the judge's finding in the Initial Decision that GSUs should not be included as a cost for any of the ancillary services, and we instead adopt trial staff's proposal to include GSU costs in ancillary services rates.

5. **Energy Imbalances**

Order No. 888-A defines Energy Imbalance Service as follows:

> Energy Imbalance Service is provided when the transmission provider makes up for any difference that occurs over a single hour between the scheduled and the actual delivery of energy to a load located within its control area. For minor hourly differences between the scheduled and delivered energy, the transmission customer is allowed to make up the difference . . . by adjusting its energy deliveries to eliminate the imbalance. A minor difference is one for which the actual energy delivery differs from the scheduled energy by less than 1.5 percent, except that any hourly difference less than one megawatt-hour is also considered minor. Thus,

> the Final Rule established an hourly energy deviation band of +/- 1.5 percent (with a minimum of 1 MW) for energy imbalance. [77]

a. Deadband

Positions of the Parties

AEP offered a deviation band (also known as a "deadband") of 1.5 percent, consistent with the figure we required in Order No. 888. [78] AIW argued that the deadband of 1.5 percent is too small and discriminates against smaller systems. AI Initial Brief at 42, AI Reply Brief at 62.

Trial staff argued that AEP complied with the Commission requirements by establishing a deadband of +/- 1.5 percent. Trial Staff Initial Brief at 73-74.

Initial Decision

The judge rejected arguments made by AIW and ruled that AEP properly included a deadband of +/- 1.5 percent, as required by Order No. 888. 80 FERC at 65,085.

Exceptions

AIW filed exceptions generally reiterating its arguments made before the judge.[79] In opposing AIW's exceptions on this issue, trial staff argues that changing the size of the deadband would amount to changing a term and condition of the Order No. 888 pro forma tariff, which is beyond the scope of this proceeding. AEP and trial staff point out that Order No. 888-A, while keeping the deadband at +/- 1.5 percent, modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW to address the concerns raised by smaller systems such as AIW.

Discussion

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77 / FERC Stats. & Regs. ¶ 31,048 at 30,229. In Order No. 888-A, the Commission clarified the definition of Energy Imbalance Service provided in Order No. 888, FERC Stats. & Regs. ¶ 31,038 at 31,960-61.

78 / When the energy imbalance is within the prescribed bandwidth, the energy may be returned in kind. When the energy imbalance is outside the bandwidth, specific rates are applicable as discussed below.

79 / AI Brief on Exceptions at 71-72; WVPA Brief on Exceptions at 23-24.

We affirm the judge. In Order No. 888-A, we addressed the issue of the size of the deviation band in detail. There, we held that a bandwidth of 1.5 percent promotes good scheduling practices by transmission customers and that the implementation of scheduled transactions should not overly burden others. [80] Also, as noted by AEP and trial staff, in Order No. 888-A we modified the minimum permissible energy imbalance deviation from 1 MW to 2 MW. [81] We therefore conclude, as did the judge, that AEP's proposals on bandwidth comply with the requirements of Order Nos. 888 and 888-A. Accordingly, we affirm the judge's finding on this issue for the reasons set forth in the Initial Decision.

b. Charges for Under-Scheduled Power

Positions of the Parties

AEP argued that a transmission customer should pay a charge of 100 mills/kWh for under-scheduled energy outside the deadband. [82] Trial staff supported this charge stating that such a charge would act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load.

AIW argued that all under-scheduled energy should be returned in kind. However, AIW asserted that a 100 mills/kWh charge may be reasonable for under-scheduled energy which exceeds the 7.5 percent (i.e., 1.5 percent for the deviation band plus 6 percent for operating reserve services) the customer purchases from AEP or supplies itself.

Initial Decision

The judge found AIW's position that all under-scheduled power be returned in kind to be inconsistent with the Order No. 888 provision that requires a separately stated charge for such under-scheduled power. The judge also found that AEP's 100 mills/kWh charge was reasonable because such a charge accounts for the fact that the imbalances occur on an hourly basis. The judge ruled that AIW's interpretation that customers that buy operating reserves from AEP are entitled to a 7.5 percent deadband is not correct, and that Order No. 888 provides for several ways in which the customer may reduce or eliminate the need for energy imbalance service, such as dynamic scheduling.

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80 / See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,232- 33.

81 / Id.

82 / 100 mills/kWh was the rate utilities typically charged their customers for emergency power service, and in Detroit Edison Company, Opinion No. --, 88 FERC ¶ 61,--- (1999) (Detroit Edison), we recently found that energy imbalance service is similar to emergency power service.

Exceptions

AI argues that a 100 mills/kWh charge might be reasonable if the deadband is expanded to include operating reserves. However, AI contends that since the judge did not expand the deadband to include operating reserves, the charge should be no greater than AEP's out-of-pocket costs. AI and WVPA argue that the charge for energy outside the deadband is too high and not cost-justified. AI Brief on Exceptions at 72; and WVPA Brief on Exceptions at 14, 22-24.

Discussion

As we explained above, "Energy Imbalance Service" is used to supply energy for mismatches between scheduled deliveries and actual loads that may occur over a single hour. We did not intend it to be used as a substitute for operating reserves. See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,230. Furthermore, we find that a 100 mills/kWh charge for underscheduled energy outside the deadband is reasonable because such a charge will act as a deterrent to transmission customers who fail to provide enough energy to meet their actual load. In addition, in Detroit Edison we recently found that energy imbalance service is similar to emergency power service, and that 100 mills/kWh is the rate utilities typically have charged their customers for emergency power service. Accordingly, we affirm the judge's finding on this issue.

6. **Losses**

a. Reserve Margin

Positions of the Parties

AEP proposed a 20 percent reserve margin in calculating costs associated with capacity required to make up for losses. AEP explained that: (1) losses are similar to firm load; (2) losses cannot be controlled and are not subject to curtailment; and (3) transmission customers do not have to buy loss service from AEP and instead are free to make alternative arrangements to supply losses. AEP Initial Brief at 43; Ex. A-28.

AIW disagreed with AEP's proposal and argued that a transmission customer is required to provide spinning and supplemental operating reserves for the full amount of its load and losses under AEP's tariff Schedules 5 and 6. Therefore, AIW asserted that an obligation to pay for a separate 20 percent reserve margin is essentially a double charge.

Initial Decision

The judge ruled that although the transmission customers have alternative ways of supplying losses, a 20 percent reserve margin for losses on top of spinning and supplemental operating reserves of 6 percent would amount to double counting of reserves. Therefore, the judge determined that a 14 percent reserve margin is appropriate in this case for calculating capacity costs for losses.

Exceptions

No party filed exceptions to the judge's decision.

Discussion

We reverse the judge's finding on our own initiative. Notwithstanding the fact that there were no exceptions filed to the judge's determination that a 14 percent reserve margin is appropriate, we find no basis for AEP's contention that any reserve margin is cost-justified for loss service. First, AEP has sponsored no studies or quantitative evidence showing that a reserve margin of any amount is cost-justified for loss service, and there is no Commission precedent supporting such a charge. Second, in Order No. 888 we neither required customers to take such a service from their transmission providers or for transmission providers to provide such a service. There is no basis for AEP to assess a charge under its open access tariff for a service that is not even offered under that tariff. Finally, we disagree with AEP's claim that losses are similar to firm load. In fact, AEP's provision of loss services is discretionary both for AEP and its customers. Thus, we find no justification for AEP's imposition of a charge for reserves for loss service.

b. Transmission Loss Factor

Positions of the Parties

AEP proposed a transmission loss factor of 3.6 percent. AIW contended that AEP's loss factor is excessive arguing that: (1) AEP did not provide any support that losses from theoretical load flow and other studies represent actual system losses; and (2) losses on AEP's local area network and distribution system (facilities below 69 KV) should be excluded from this loss factor calculation because many of AEP's transmission customers provide losses on their own local area networks and distribution system. To rebut AIW's claim that it was improper for AEP to roll-in the local area networks and distribution losses, AEP argued that its charging of losses associated with all transmission facilities used to provide service is in accordance with Commission policy favoring rolled-in pricing. [83] Trial staff did not contest AEP's loss factor.

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83 / AEP cited Kentucky & Ohio in support of its claim. AEP Initial Brief at 43.

Initial Decision

The judge determined that AEP's loss factor of 3.6 percent is reasonable. The judge rejected AIW's claim regarding local area network and distribution use stating that AIW did not present any evidence to prove its claim, nor did it offer any evidence showing what percentage should be assigned to that portion of the losses allegedly associated with the distribution function. He held that AIW did not provide any arguments to rebut AEP's reliance on Kentucky Power. Specifically, that case affirmed a prior Commission order [8484] approving an increase in the AEP loss factor from 2.0 percent to 3.6 percent. The Commission held in Appalachian II that:

> AEP's proposal is entirely consistent with the Commission's requirements for charging customers for transmission losses. . . . Customers' service is provided by and priced on the basis of the AEP integrated transmission system . . . . [[85]]

Exceptions

AI filed exceptions in which it generally reiterates the same arguments made by AIW before the judge. AI Brief on Exceptions at 72-73.

Discussion

We affirm the judge's finding, adopting a loss factor of 3.6 percent, for the reasons set forth in the Initial Decision. However, we note that the AEP study includes all facilities including GSUs. Because we have ruled that GSUs should be assigned to production, we will require AEP to recalculate the transmission loss factor to exclude real power losses attributable to GSUs.

The Commission orders:

(A) The Initial Decision issued in this proceeding on August 7, 1997 is hereby

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In Kentucky & Ohio, the Commission specifically approved the rolled-in method with
respect to losses on the AEP System. 64 FERC at 61,923.

84 / Appalachian Power Company, et al., 63 FERC ¶ 61,165 (1993) (Appalachian II).

84 / Appalachian Power Company, et al., 63 FERC ¶ 61,165 (1993) (Appalachian II).

85 / Id. at 62,149.

affirmed in part and reversed in part, as discussed in the body of this order.

(B) AEP is hereby directed to submit a compliance filing within 60 days of the date of issuance of this order. However, if a request for rehearing is filed, AEP shall make its compliance filing within 30 days of the date the Commission disposes of the request for rehearing.

(C) Within 30 days of acceptance of the compliance filing, AEP shall make refunds, together with interest calculated pursuant to 18 C.F.R. § 35.19a (1999). Within 15 days of the date of payment of refunds, AEP shall file a report showing the computation of refunds and interest paid. A copy of the refund report shall also be sent to the affected state commissions.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

Secretary

Document Content(s)

APPENDIX C

FERC INITIAL DECISION ISSUED JAN 14, 1999

Docket No. OA96-77

Consumers Energy Company

UNITED STATES OF AMERICA86 ferc ¶ 63,004
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company	)	**Docket Nos. OA96-77-000**
	)	**ER97-1502-000**
	)	**and ER98-1247-000**

INITIAL DECISION

(Issued January 14, 1999)

APPEARANCES

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Cheryl M. Feik, Esq., Gary D. Bachman, Esq., and Jay T. Ryan, Esq., on behalf of **Edison Sault Electric Company**

Mark S. Hegedus, Esq., Thomas C. Trauger, Esq., Robert A. Jablon, Esq., Thomas J. Byrne, Esq., and Sara C. Weinberg, Esq., on behalf of **Michigan Public Power Agency, Michigan South Central Power Agency; Wolverine Power Supply Cooperative; and Michigan Public Power Rate Payers Association**

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William J. Cowan, Presiding Administrative Law Judge

PROCEDURAL BACKGROUND

This proceeding originally stems from the issuance by the Commission on April 24, 1996, of Order No. 888, requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to, among other things, have on file open access transmission tariffs that contain minimum terms and conditions of non-discriminatory service. [1] The compliance filings were to be made by July 9, 1996. Utilities subject to this requirement were divided into Group 1 (utilities that had tendered for filing open-access transmission tariffs before the date of issuance of Order No. 888) and Group 2 (utilities that had not tendered pre-Order No. 888 tariffs). Additionally, Order No. 888 provided for a blanket suspension for all Group 1 filings that included new rate proposals, of which this is one, and directed that they go into effect, subject to refund, on July 9, 1996. Pursuant to the Commission's order, Consumers Energy Company ("Consumers Energy", "CECo" or "the Company") filed its open-access tariff in Docket No. OA96-77-000 on July 9, 1996. On January 29, 1997, the Commission accepted the non-rate terms and conditions of the Tariff without ordering an evidentiary hearing. American Electric Power Service Corp., et al., 78 FERC ¶ 61,070 at 61,269 (1997). By Order issued July 31, 1997, the Commission set Consumers Energy's and other Group 1 public utilities' rates for hearing. Allegheny Power System, Inc., et al., 80 FERC ¶ 61,143 (1997).

On January 31, 1997, Consumers Energy, in Docket No. ER97- 1502-000, filed an unexecuted transmission service agreement ("TSA") and a network operating agreement ("NOA") for service to the Municipal Cooperative Coordinated Pool ("MCCP") [2] under Consumers Energy's open access transmission tariff. MCCP protested the unexecuted TSA and the NOA and on April 1, 1997, the Commission accepted the

1 / See Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. and Regs., Regulations and Preambles 1991-1996 ¶ 31,036 (1996) ("Order No. 888"), Order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. and Regs. ¶ 31,048 ("Order No. 888-A"), Order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), ("Order No. 888-B"); Order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998)("Order No. 888-C").

2 / MCCP is comprised of the Michigan Public Power Agency ("MPPA") and the Wolverine Power Supply Cooperative, Inc. ("Wolverine").

agreements for filing, suspended and made them effective subject to refund, and established hearing procedures. Consumers Power Co., 79 FERC ¶ 61,001 (1997). On August 20, 1997, Chief Administrative Law Judge, Curtis L. Wagner, Jr., issued an order consolidating Docket No. ER97-1502- 000 with Consumers Energy's on-going open access proceeding in Docket No. OA96-77-000.

On December 30, 1997, Consumers Energy filed in Docket No. ER98-1247-000, an unexecuted TSA for service to the MCCP from January 1, 1998, to December 31, 1998, to replace the expired comparable TSA filed in Docket No. ER97-1502-000. In all material respects, this TSA had the same terms and conditions as the prior unexecuted TSA in Docket No. ER97-1502-000 filed by Consumers Energy for service to MCCP from January 1, 1997 to December 31, 1997. On February 27, 1998, the Commission issued an order consolidating the filing in Docket No. ER98-1247-000 with, and making it subject to the outcome of, the ongoing consolidated proceedings in Docket Nos. OA96-77-000 and ER97- 1502-000. Consumers Energy Co., 82 FERC ¶ 61,206 (1998).

Active participants in this proceeding include Consumers Energy, the Michigan Systems ("Michigan Systems" or "MS"), [3] the Association of Businesses Advocating Tariff Equity ("ABATE"), the Board of Public Works of the City of Holland, Michigan ("Holland"), The Michigan Public Service Commission ("MPSC"), Edison Sault Electric Company ("Edison Sault"), and Commission Staff ("Staff"). On March 13, 1998, pretrial briefs were filed by all active parties, with the exception of the MPSC, which filed a statement in lieu of pretrial brief. A hearing was conducted commencing March 17, 1998 and concluding April 2, 1998. Subsequent to the hearing, initial and reply briefs were filed on May 21, 1998 and June 19, 1998, respectively by all active parties except the MPSC.

On June 29, 1998, Chief Administrative Law Judge Curtis L. Wagner, Jr. designated the undersigned to substitute for Administrative Law Judge Debra Morriss, who was no longer available to serve, and directed that I take further actions in these premises.

This initial decision follows the sequence of the Chart of Issues developed in this proceeding. The positions of the parties on each issue are set forth first, followed by a ruling which contains an evaluation of the evidence and the decisional rationale. While most noteworthy arguments and supporting references are discussed, the omission of references to particular arguments or record citations does not mean that they have not been considered. All arguments raised and evidence presented have been evaluated with care.

ISSUE 1 A -- Consumers Energy's Facilities That Can Be Deemed Part of Rate Base

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3 / Michigan Systems consist of the MPPA, Michigan South Central Power Agency, Wolverine, and Michigan Public Power Rate Payers Association ("MPPRPA").

Michigan Systems challenge the inclusion by CECo in its rate base of facilities, primarily 23 kV and 46 kV facilities and higher voltage radial lines, which they contend have not been shown to provide service to transmission customers under CECo's Open Access Transmission Tariff ("OATT") to any greater extent than comparable facilities owned by transmission customers. MS I.B. at 5. Allocation of the costs of such facilities to CECo's transmission customers who do not purchase power from CECo or otherwise use such facilities subsidizes CECo's service to its own power customers at the expense of transmission customers who do not require the facilities for service under the OATT, MS contends. Id. at 5-6.

To prevail on the issue of inclusion of these low voltage facilities in rate base, MS argues that CECo must: (1) show that the facilities at issue are integrated into CECo's transmission plans or operations to serve the Company's power and transmission customers; and (2) satisfy the Commission's comparability standard. MS maintains that the Company has failed to satisfy either of these criteria. MS I.B. at 6-31.

The Company contends that it does not bear the burden of proof that each individual segment of its transmission system should be included in its rate base. CECo I.B. at 5. Its rate base claim here, CECo asserts, is predicated upon the historic rolled-in approach employed to develop its 1992 Open Access tariff, which in turn was based upon prior unbundled transmission tariffs going back to the 1980's. Id. The Company further points to the testimony of its witness, Erickson, who stated that all of CECo-owned transmission facilities are integrated into the plans and operations of the Company to serve its customers. Ex. MS-53; see also, Exs. CE-16 at 1; CE-29 at 4.

Staff argues that CECo has included in its rate base those facilities traditionally rolled into transmission rates by public utilities. Staff R.B. at 3. Staff claims that it is "unnecessary to unscramble the egg and review [CECo's] system on a facility-by-facility basis to ensure comparable treatment of Michigan Systems." Id. Staff points to the analysis of its witness Oxendine, who reviewed and identified the MS facilities that performed functions similar to those facilities rolled into CECo's rates, and are deserving of comparable treatment. Id.

According to MS, in order to recover the cost of its facilities through transmission rates, the transmission provider must demonstrate that the facilities claimed for inclusion in its rate base serve its power and transmission customers. MS I.B. at 6-9. CECo has failed to demonstrate, MS contends, that any single facility, or the facilities as a whole, provide transmission service, relying, instead, on the contention that the entire system provides service under the tariff. Id. at 7. MS cites references in the transcript to Company witness testimony where MS alleges CECo conceded that not all of its facilities are needed to serve transmission customers (Tr. at 180-82) and that many facilities play little or no role in serving transmission customers (Tr. at 372). Moreover, MS argues, CECo has failed to demonstrate that its facilities are integrated, and, accordingly entitled to "rolled in" rate base treatment. MS I.B. at 9.

Turning to its comparability argument, MS grounds its position here on the following language in the Commission's Order No. 888:

> We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

Order No. 888 at 31,743, n.452.

Also, MS cites the following passage from the Commission's Order No. 888-A:

> As we noted in FMPA II, this fundamental cost allocation concept applies to the transmission provider as well. Just as the customer cannot secure credit for facilities not used by the transmission provider to provide service, the transmission's provider cannot charge the customer for facilities not used to provide transmission service.

Order 888-A at 30,271, n.277, citing Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC ¶ 61,006 at 61,010, n.48 (1996)("FMPA II").

MS claims that CECo currently rolls into its transmission rate base facilities whose purpose it is to deliver power from higher voltage bulk transmission facilities to its retail customers. Ex. MS-16 at 13. Such facilities, MS argues, play no role or very little role in serving transmission customers, but may be necessary for CECo to serve itself as a network customer. MS I.B. at 10. According to MS, transmission customers also pay the costs of their own facilities that similarly serve to deliver power from higher voltage bulk transmission facilities to retail customer service areas. Id. CECo, however, does not share in the costs of such facilities, MS maintains. This asserted lack of comparability is at the heart of MS' argument here. According to MS, CECo integrates all of its load using the transmission grid, and seeks to allocate the costs of transmission facilities serving loads among all customers, even if those facilities are not necessary to serve transmission customers. Id. In such circumstances, MS contends, all transmission facilities used to serve those loads, including customer-owned facilities, must be considered part of the transmission grid. Only then will comparability be maintained, MS asserts. Id. at 10-11.

Here, comparability requires either that CECo facilities that are not necessary to serve transmission customers be deleted from the rate base, or that customer-owned facilities supporting the grid receive appropriate credits, argues MS. However, MS maintains, neither CECo nor Staff studied whether CECo facilities included in rate base were required to serve transmission customers. MS contends that CECo and Staff treated CECo's facilities as the embedded or native facilities, while treating customer-owned plant as incremental, and putting individual customer facilities "through the wringer." MS I.B. at 11. MS goes on to argue that the so-called Megawatt-Mile ("MW-Mile") analyses performed by Staff and CECo fail to treat customer facilities comparably and provide no information about whether a line is important or necessary, only whether a specific line participates in a power transfer. Id. at 13. MS further argues that the CECo 46 kV system participated in certain modeled transactions to a lesser extent than MS' own facilities. Ex. S- 30 at 7-10.

MS concludes that certain CECo facilities must be removed from rate base, unless customer-owned facilities that perform comparable functions receive appropriate credits. These facilities include generator step-up transformers and related substation equipment; radial lines; and facilities predominantly serving a local area function, such as subtransmission facilities which link CECo's bulk transmission system to its distribution substations. Ex MS-16 at 47-48; see also Ex. MS-21 at Sheet No. 2. MS contends that additional evidence of facilities appropriate for removal from CECo's rate base is set forth in testimony that Company witness Erickson presented in an MPSC proceeding to determine which facilities should be classified as transmission facilities for purposes of delivery of electricity purchased by retail electric customers. Ex. ABATE-16. There, Mr. Erickson testified that facilities that connect generators to the transmission grid should be re-classified as generation- related, and 138 kV radial lines that supply 138/46 kV substations, 138 kV to 46 kV and 138 kV to 23 kV substations and all 46 kV and 23 kV lines should be re-classified as distribution facilities. Id. at 7-13.

Ruling on Consumers Energy's Facilities That Can Be Deemed Part of Rate Base:

We deal here with MS' argument that the Company has not demonstrated that its facilities can be included in the rate base. First, CECo and Staff are correct that the Company is not required initially to demonstrate that all expenditures were prudent or that each and every item of plant in its claimed rate base properly belongs there. However, upon a showing of serious doubt about the prudence of particular expenditures by other case participants, or, by analogy, doubts about the proper inclusion of particular plant in rate base, the applicant has the burden of dispelling such doubts and proving that the expenditures were prudent or that the plant is properly in rate base. Minnesota Power & Light Co., 11 FERC ¶ 61,312 at 61,644-5 (1980).

Here, use of the historic, rolled-in rate base is an acceptable point of departure for CECo. Its testimony that all of its transmission facilities are integrated into its plans and operations to serve its customers was not challenged by specific references to transmission lines or substations that are not used to provide transmission service. The record citations offered by MS to support its position fail to do so. At Tr. 180-82, the CECo witness was responding to hypothetical wheeling transactions where CECo's 46 kV transmission line was described as not a significant factor, and, at Tr. 372, the witness actually replied that all of the facilities are providing service to the Company's customers in some form.

However, the Company has petitioned the Commission for a declaratory order in Consumers Energy Co., Docket No. EL98-21-000 that would accept a determination of the MPSC as to which of its facilities should be classified as transmission facilities for purposes of delivery of electricity purchased by retail electric consumers. CECo has described the MPSC determination as follows:

(1) With the exception of approximately 180 miles of radial 138 kV lines and associated facilities and retail meter facilities, all of CECo's facilities that transmit electricity at voltages of 120 kV or above should be classified as transmission facilities.

(2) All of CECo's facilities that transmit electricity at nominal voltages of less than 120 kV, approximately 180 miles of radial 138 kV lines and associated facilities and all retail meter facilities, regardless of voltage, should be classified as local distribution facilities.

(3) CECo's generator step-up transformers, lines and other facilities used to connect CECo's generating plants with its transmission system should be classified as generation facilities.

Staff I.B. at 7, citing CECo's letter dated January 22, 1998, in Docket No. EL-98-21-000.

Accordingly, that petition would give effect to some of the changes in rate base sought here by MS. I take notice that the Commission granted CECo's petition in a Letter Order issued July 29, 1998, concluding that certain facilities identified in that petition are State-jurisdictional local distribution facilities and others, also identified in the pleadings, are Commission- jurisdictional transmission facilities. The Commission also decided not to delay action on CECo's request pending the filing of revised rates, as had been requested by MS in that docket. Instead, the Commission has stated that, after the transmission- related costs have been identified, rates should be developed to reflect those costs. Accordingly, the rate base initially claimed by CECo in the instant dockets must now be adjusted to account for the subsequent development concerning a re- classification of its plant in the MPSC proceeding, which the Commission has now accepted.

Claims relating to comparability, and the issue surrounding fair and equitable treatment of customer facilities in the new era of transmission policy ushered in by Order No. 888, are more appropriately considered in Issue 1 B, next following.

ISSUE 1 B -- Credits for Customer-Owned Facilities

Continuing its argument that credits should be received for facilities owned by network service customers on the grounds that such facilities are integrated into the plans and operations of CECo to serve its power and transmission customers, MS claims to have demonstrated that MCCP facilities qualify for credits under the provisions of Section 30.9 of CECo's OATT. MS I.B. at 34. It seeks $9.8 million ($13.5 million if Lansing becomes a network customer) annually in revenue credits from CECo for Michigan Systems' solely-owned transmission facilities that are connected to CECo's transmission system, contending that such facilities are integrated into the plans and operations of Consumers Energy to serve the power and transmission customers of CECo.

Section 30.9 of the OATT [4] provides as follows:

> The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

The Commission explained:

> The intent of section 30.9 of the pro forma tariff is that, for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid. Indeed, in the Final Rule we explicitly stated that the fact that the transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over these facilities.

Order No. 888-A at 30,271.

Also pertinent, is the following statement from the Commission's Order No. 888:

> The presumption of many commentators that a customer's subscription to transmission service somehow transforms the provider's and customer's systems into an expanded and integrated whole to the mutual benefit of both is not a valid one. As we ruled in Florida Municipal Power Agency v. Florida Power & Light Company, ("FMPA"), it must be demonstrated that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider. Specifically, we stated that:

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4 / This provision appears both in CECo's tariff and the Commission's pro forma tariff appended to its Order 888-A.

> The integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition in such cases. The mere fact that a section 211 requestor has previously constructed facilities is not sufficient to establish a right to credits.

> The fact that a transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities - a key requirement of integration.

Order No. 888 at 31,742-43. (Footnotes omitted; emphasis in original). [5]

Another Commission decision is also pertinent here. In FMPA II, the Commission stated:

> We decline to grant FMPA the requested credits; likewise we will deny its conditional request for rehearing. We reject FMPA's argument that, because it must pay a rate reflecting the cost of all of Florida Power's transmission facilities, it is entitled to a credit reflecting the cost of all of FMPA's transmission facilities. The final order did not direct a merging of the parties' transmission systems or the operation of a joint transmission network.
>
> *****
>
> While the FMPA facilities may serve a transmission function on the FMPA side of the interconnection point between FMPA and the Florida Power system, they are not used by Florida Power to provide transmission service to FMPA or any other party. Nor are they used to transmit Florida Power's power to its non-FMPA customers.
>
> *****
>
> The fact that the Ft. Pierce/Vero Beach line constitutes a parallel path and is subject to occasional loop flow does not, in and of itself, compel a conclusion that the line now operates as part of the Florida Power integrated transmission network.
>
> *****
>
> Also, while the Ft. Pierce/Vero Beach line may be redundant to certain facilities comprising the Florida Power network, unneeded redundancy

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5 / FMPA is found at 67 FERC ¶ 61,167 (1994).

> provided by FMPA cannot qualify for a credit any more than an unnecessary Florida Power transmission facility could qualify for cost recovery. In sum, because the Ft. Pierce/Vero Beach line is not used by Florida Power to provide transmission service to itself or others in the Florida Power control area, its existence has no effect on Florida Power's cost of providing service to any Florida Power customer, including FMPA.

74 FERC at 61,009-10.

Additionally, Michigan Systems point to the footnote on comparability provided by the Commission in Order No. 888 at 31,743, n.452, to wit:

> We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

This precedent sets the stage for Michigan Systems' argument that certain MCCP facilities are integrated into CECo's plans or operations to serve CECo's customers, in the manner contemplated by the Commission in its various statements setting forth guidance on what it takes to qualify for a customer facilities credit. [6] MS further argues that the MCCP transmission facilities provide measurable benefits.

To support its claim of integration, MS contends that the facilities at issue are necessary to serve a CECo network customer, meaning MCCP, and that they integrate the MCCP loads with other loads and resources connected to the CECo transmission system. If credited, the facilities would continue to serve CECo's power and transmission customers as they do already. MS I.B. at 35-36.

MS asserts that these facilities provide the following functions:

> (1) They convey power and energy from MCCP member-owned generation sources to load aggregation points on the transmission grid for delivery to other points on the transmission grid;
>
> (2) They convey power and energy from MCCP member-owned generation sources to the transmission grid for delivery to points of interconnection to other electric systems;
>
> (3) They convey power and energy from other generation sources through interconnection points to load aggregation points on the MCCP member

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6 / The MCCP transmission facilities for which credit is claimed include the "MCP Integrated System," which includes the facilities of Wolverine, Grand Haven, Traverse City and Zeeland and the "Lansing Integrated System." Ex. MS-16 at 25-29.

systems;

(4) They provide parallel paths in order for the integrated system (CECo plus MCCP) to continue operating despite outages of transmission facilities along other paths; and

(5) They produce and convey to the grid reactive power to control voltage on the transmission grid.

MS I.B. at 38.

MS contends that the MCCP facilities that make up the MCP Integrated Systems are functionally integrated in a manner comparable to CECo facilities which perform much the same mission as the MCCP facilities described above. MS witness Reising concluded that the transmission facilities owned by the MCCP member systems integrate network loads, generating resources and interconnections with other parties. He further contends that if Lansing was included as a network load under the MCCP network service, its facilities would also qualify for a credit for the same reason. Both the MCP and Lansing Integrated Systems are interconnected to CECo at multiple locations (eleven for MCP and two for Lansing), MS maintains. As a result, MS argues, power flows across these interconnections are bilateral. Power can and does flow across the MCP and Lansing systems, into some interconnections with CECo and out of other interconnections from CECo, claim Michigan Systems.

MS argues that the credit requirements set by the Commission have been satisfied in that customer-owned facilities of MCCP provide service to CECo's transmission customers, specifically MCCP, which is a CECo transmission customer. Further, MCCP facilities support the transmission grid and are available to other transmission customers under CECo's OATT, fulfilling the integration requirement that the facilities seeking credit provide service to other transmission customers, MS contends.

MS further claims that other indicia of integration are apparent, including: (1) facilitating the delivery of power produced by generators or purchased from interconnected systems to loads; Compare Ex. MS-16 at 35 and Tr. at 335-37 to Tr. at 188-89, 203-05; see also Ex. MS-23; (2) facilitating off-system sales; (3) permitting reliance on other systems for reserves; and (4) permitting delivery of power from one point on the grid to another point. MS I.B. at 41.

Michigan Systems claim to have proved the integrated nature of the MCP and Lansing Integrated Systems through load studies performed using CECo's own power flow model. Ex. MS-16 at 33.
Regarding MCP, three ties were analyzed including ties between Wolverine and CECo in the Odin, Airport and Hersey areas. Two had flows normally from CECo to Wolverine. Hersey normally delivered power from Hersey to CECo. Id. After a line outage near each tie, the direction of the flow reversed on two of the ties and all three delivered

power to CECo. These bi-directional flows evidence integration, according to MS witness Reising. Id. at 33-34. MS similarly analyzed the Lansing Integrated System using the CECo base case. Michigan Systems contend that the Lansing system picked up flows as a result of the outage of CECo's facilities. MS I.B. at 42-3; see also Ex. MS-25 at 2.

A study of the effect of a constraint along CECo's AEP interface also demonstrates the integrated nature of the MCCP and CECo facilities, Michigan Systems maintain. Positing the import into the CECo system of 735 MW over the two ties with AEP, Mr. Reising demonstrated the effect of an outage at one of the ties. MS I.B. at 43; see Ex. MS-26 at 2-3. The remaining tie would experience an increase in loadings from 44.2 percent to 95.1 percent. By increasing generation at Lansing by 75 MW, the loadings on the in-service tie drop from 95.1 percent to 93.3 percent. Greater increases in generation produce more reductions in line loadings, Mr. Reising maintains. This represents significant relief that could not be realized without the MCCP transmission facilities, he contends. MS I.B. at 43.

Turning to its argument that the MCCP facilities provide measurable benefits in terms of capability, reliability, and coordinated operation of the grid, MS first contends that the criteria against which its claim of measurable benefits is to be judged should be comparable to that employed to judge the benefits of the transmission provider's facilities. Its facilities would be available for service under CECo's OATT. Ex. MS-16 at 45. MS maintains that this would eliminate undesirable rate pancaking, encourage electrical coordination and reliability, and would lead to a more efficient grid. See Ex. MS-1 at 47-48; Tr. at 1638-39, 767-768; Ex. MS-34 at 18; Tr. at 1675-76. Access to generation owned or controlled by MCCP also benefits CECo's power customers to the extent CECo needs power, MS argues. Further benefits take the form of reduced transmission investment; an increase in the loads against which the costs of the system can be allocated (See Ex. MS-16 at 36, Ex. MS-34 at 9, 16, 17-18); and coordinated grid operation and reliability through re-dispatch opportunities and the availability of alternate-sourced generation (See Exs. MS-16 at 35, 38-40; MS-34 at 6; MS-16 at 39).

MS further argues that comparability is itself a basis for the award of credits. Claiming to have demonstrated that the facilities for which it seeks credit are comparable to the ones that CECo claims are integrated into its plans and operations, MS
sees a compelling basis for the assignment of credits for MCCP facilities. MS I.B. at 71-77. Yet another basis for its claim of entitlement to credits here for MCCP facilities is the Commission's adoption of load ratio share pricing for network service under the OATT, citing to Order No. 888 at 31,736.
Under this theory, credits are not predicated merely upon interconnection, they are based upon the use of transmission to integrate the customers' load and resources, according to Michigan Systems. MS I.B. at 82-83.

Moreover, MS argues, the absence of credits, in the context of load share pricing, injures MCCP. MS I.B. at 83-86. It contends that CECo's failure to recognize the

Lansing transmission as eligible for credits while insisting that the Lansing load be designated as network load under network integration service created the necessity for MCCP to exclude the Lansing loads from the rest of the MCCP's integration activities or incur unreasonably high transmission charges. See Ex. MS-24. This has forced MCCP to resort to the purchase of short-term point-to-point transmission from CECo. Had MCCP included Lansing under Network Integration Transmission Service, MCCP would have incurred an annual cost of approximately $6,200,000. Ex. MS-1 at 38.

Michigan Systems have calculated credits, which it claims at Exs. MS-16 at 45-47 and MS-30. MS contends that no party has offered evidence disputing these calculations and urges their adoption. MS I.B. at 88.

Consumers Energy contends that the Commission rejected, in Order No. 888-A, the broad interpretation of integration urged here by MS when it reconsidered the original pro forma tariff language of Section 30.9. As noted above, the Commission stated that, to be eligible for a credit, additional benefits to the transmission grid in terms of capability, reliability and coordinated operation of the grid would be required, in addition to integration with the transmission provider's system.

CECo's position is that only certain 345 kV transmission lines jointly-owned by CECo with MCCP's members MPPA and Wolverine would qualify for a credit, because no other MCCP facilities provide the additional capability or reliability benefits to Consumers Energy's transmission grid or are relied upon by CECo in any way to provide transmission service to itself or others.

CECo offers the rebuttal testimony of Mr. Erickson, an Executive Engineer in the Company's Transmission Planning and Performance Division. He analyzed MS witness Reising's testimony and, after conducting load flow studies, concluded that neither the MCP nor Lansing Integrated Systems of MCCP are integrated into the plans and operations of CECo to serve its power and transmission customers. Ex. CE-73 at 14, 17. Regarding the MCP Integrated System, he made the following claims to support his position:

- MCP has only one transmission line operated at voltages of 138 kV or above which is not radial to 138/69 kV transformers -- the so-called "Airport Line," a WPSC facility extending from CECo's Livingston Substation to CECo's Airport Substation.

- All ten 138 kV interconnection systems between CECo and the MCP Integrated System were installed at the request of MCCP or its predecessors to receive power from CECo's system.

- Construction of interconnections with the MCP Integrated System did not eliminate the need for any new CECo transmission facilities.

- CECo can supply its own load and the load of other CECo transmission customers without reliance on the MCP Integrated System.

Ex. CE-73 at 16.

Noting that the Airport Line is considered by Staff as potentially eligible for a credit, Consumers Energy argues that: (1) this line was not jointly planned to provide benefits to CECo; (2) the line was located and designed in way that was undesirable to CECo; (3) the line does not improve CECo's ability to supply load to Alpena during a line outage contingency, but instead increased the load to be served under outage conditions;
and (4) the line provides no benefit to CECo or other transmission customers from either a cost or performance perspective. Ex. CE-73 at 19-23.

Further, Consumers Energy's witness Erickson contends that the backbone 69 kV portion of the MCP Integrated System does not have the capability to transmit significant amounts of power. Id. at 22. Neither does the existence of the MCP system prevent violation of any CECo planning criteria or eliminate the need for new transmission facilities, the CECo witness contends. Id. at 22-24.

The Hersey 46 kV interconnection, requested by CECo, ceased to have any value to CECo upon completion of CECo's 138 kV facilities in 1992, and the Company has requested its retirement because it adds to its operating costs. Also, CECo contends that the MCP Integrated System is not useful to CECo in providing transmission across its system in power transfers such as from AEP to Ontario Hydro. Ex. CE-73 at 30-31. Moreover, CECo argues, the Lansing 138 kV line paralleling CECo's 138 kV Oneida to Delhi line is the equivalent of a redundant line, as demonstrated by load flow studies performed by Mr. Erickson. Id. at 34-38; see also Ex. S-30 at 19-21.

CECo claims that MCCP would actually assert a right to a payment from CECo if subtracting MCCP's credit under Section 30.9 from its CECo bill for Network Service resulted in a negative number. Thus, CECo contends that Michigan Systems' proposal for extensive credits would result in a bizarre anomaly -- CECo paying millions of dollars annually for the privilege of providing network service to the MCCP. CECo I.B. at 18; Tr. at 1394-5, 1449.

Staff's position is that a small portion of MCCP facilities qualify for a credit, but not the full amount requested by Michigan Systems. Staff I.B. at 5. Staff maintains that the "snapshot" load flow analysis provided by Michigan Systems, where four of the thirteen interconnection points between member systems of MS and Consumers Energy were studied, does not demonstrate that the claimed facilities are integrated with CECo's transmission facilities. Tr. at 1683. There is, according to Staff, no evidence that Michigan Systems' facilities would benefit the entire integrated transmission system. Nor do redundant facilities meet the Commission's revenue credit criteria, argues Staff. Allowing credits for facilities that are not integrated and provide no system-wide benefit would result in an improper cross-subsidization of those facilities by other transmission users, Staff claims. Tr. at 1694.

Staff has identified 60 miles of 138 kV lines and related transmission facilities owned by WPSC (the Airport line) that may be used to serve the integrated network load and, therefore, are eligible for a credit. See Exs. S-30; S-31. Additional MS facilities may qualify for credit in the future, Staff contends, particularly if Lansing becomes a network customer. Staff I.B. at 7.

Staff is also critical of MS' complaint regarding a lack of comparable treatment in the analysis of CECo's facilities, which MS says have been accorded presumptive validity whereas MS facilities were "put through the wringer." Staff says that Consumers Energy includes in its rate base those facilities traditionally rolled into transmission rates by public utilities. To review a transmission provider's facilities on a facility-by- facility basis would be an incredibly complex and unworkable job, according to Staff. Tr. at 1695. Staff claims that there is no need to engage in any unscrambling of CECo's facilities to ensure comparable treatment of Michigan Systems. Staff I.B. at 8. Finally, Staff makes the same observation that CECo did, i.e., that MS claims far more in credits from CECo than it pays to the Company for transmission service. This anomaly, Staff claims, would unjustifiably burden CECo's other customers. Id.

Edison Sault urges denial of MS' request for credits, contending that Michigan Systems have failed to produce any evidence that would clearly demonstrate that their facilities are integrated with the planning and operation of CECo's transmission facilities. ES I.B. at 13. MS fails to pass the Commission's integration test, Edison Sault argues, contending that mere interconnection is not enough, that MS is required to prove the two systems comprise an integrated whole. Id. This would entail, according to Edison Sault, that the transmission provider be able to provide transmission service to itself or other customers over those facilities. Id. The MS member facilities are duplicative and not needed by CECo to deliver power, Edison Sault contends. Id. at 13-14. MS witness Reising's test for comparability -- that comparable facilities are all customer owned facilities that function in the same manner as CECo's rate based facilities -- is far too liberal, according to Edison Sault. Id. at 14. Under such a construction, there would be no way to delineate facilities that truly warrant credits. Such a conclusion would also burden Edison Sault, it contends, because CECo does not need MCCP's facilities to deliver power to Edison Sault. Id. at 15.

In reply, MS argues that CECo seeks to have its cake and eat it too, in that it presses for inclusion in rate base on a rolled in basis of all of its own facilities classified as transmission facilities under the Commission's Uniform System of Accounts, yet would apply a wholly different standard to judge whether customer facilities are entitled to a credit. MS R.B. at 3. MS points out that CECo defines its grid by recognizing the integrated nature of all facilities necessary to serve its customers. Under that definition, MS contends, customer facilities should be entitled to the same treatment. Otherwise, Michigan Systems claim, comparability will not be achieved. Id. at 5.

MS dismisses CECo's arguments that FMPA II supports the Company's position. MS points to the Commission's language at 74 FERC ¶ 61,010, n.48: "This fundamental cost allocation concept applies to Florida Power as well as FMPA. Just as FMPA cannot obtain credits for facilities not used by Florida Power to provide service, so Florida Power cannot charge FMPA for facilities not used to provide transmission service." This, MS argues, makes clear that comparability is the rule. MS goes on to argue that in FMPA II, the Commission sought balance among the definition of the grid, the inclusion of network load to pay for network service, the allowance of credits for customer transmission, and the inclusion of company transmission investment in rate base. MS R.B. at 7. A similar approach here would, MS contends, result in credits for MS' ownership portions of the 345 kV grid and for facilities that provide direct benefit to the grid, such as those proposed to be included by Staff. Id.

Contending that there are alternate ways to achieve comparability, Michigan Systems suggest that CECo's position fails in that it would apply its expanded rate base, yet define the grid in a very different way to calculate credits for customer facilities.

MS is also critical of what it describes as the "CECo-lite" position advocated by Staff, where some MS facilities would be entitled to credits, but where no load studies were performed to validate that all of CECo's facilities contribute to the grid. MS. R.B. at 11-12. Further, MS contends that many of Staff's positions are off-the-mark or wrong. MS maintains:

- It does not seek $13,548,445 in credits because that number includes Lansing becoming a network customer, which it is not.

- Staff's statement that MS seeks credit for 1,600 miles of transmission lines is incorrect because that figure includes the Wolverine facilities for which it does not seek credit.

- Staff's characterization of MS load flow study as a "snapshot" implies inappropriately that the studies are not representative.

- Staff's implication that MCCP claims credit for redundant facilities is not based upon a study to determine whether it is MCCP's or CECo's facilities that are redundant.

- Staff's limitation of credits is based upon faulty assumptions.

- Staff's allegation that MS has failed to provide the cost of facilities to determine appropriate credits is wrong, citing to Exs. MS-34 at 15, and MS-35.

· There is no conceivable basis upon which to disallow credits for the Lansing facilities, assuming Lansing becomes a network customer, because those facilities provide a direct path through the transmission network.

MS R.B. at 15-17.

Responding to CECo's points, MS maintains that:

· In contending that the MCP Integrated System has only one transmission line operated at voltages of 138 kV or above that is not radial to 138/69 kV transformers, CECo leaves out an important 138 kV line owned by Wolverine that operates in parallel to the CECo system and through which power can flow in either direction. MS I.B. at 56, n.9.

· For the purpose of determining whether facilities are integrated, it is immaterial who requested interconnections.

· In arguing that construction of the MCP Integrated System facilities did not eliminate the need for any new CECo facilities, CECo ignores the benefits that are derived by CECo's power and transmission customers as a result of facilities built by MCCP members.

· CECo has not proven that it can supply its own load and that of other CECo transmission customers without reliance upon the MCP Integrated System.

· CECo has carefully limited its claim that the Airport Line does not increase its ability to serve load at Alpena during a line outage. The line is necessary to serve load, and if CECo wanted better joint planning, it should have requested it.

· Company witness Erickson's studies show that: the MCP Integrated System facilities make a contribution to cross system transactions, redundancy is a component of good transmission planning, and CECo failed to subject its own facilities to similar tests.

MS R.B. at 17-21.

In reply to Edison Sault, MS argues that Edison Sault's system costs should not increase under the enlightened transmission planning, operation and pricing system being facilitated by the Commission in its recent orders; that to follow a different course would be akin to "Balkanization" of systems leading to pancaking of rates, poor planning and functional difficulties. Comparability requires the result it advocates, Michigan Systems contend, even if Edison Sault has to pay higher costs. MS further points out that under its proposals, customers of CECo, like Edison Sault, who themselves own extensive transmission facilities, would be entitled to appropriate credits for their investments. MS R.B. at 13.

Ruling on Credits for Customer-Owned Facilities:

First, it is appropriate to recognize that the Company's transmission rate base needs to be adjusted to comport with the Commission's ruling on its petition in Docket No. EL98-21-000 for
a declaratory order, discussed in Issue 1 A above. That fact alone brings the present issues surrounding Michigan Systems' claims for credits into more proper balance.

The Commission's embarkation upon a new transmission policy designed to foster open access and equitable rate treatment of transmission facilities, expressed in its Order Nos. 888, 888-A, 888-B and 888-C, will require some fresh thinking and will necessitate some justified departures from the rules of the past. Notably, it may no longer be sufficient for a company making a claim for rate base inclusion of its transmission system to say, as CECo has here, with Staff's surprising support, that it has appropriately included facilities traditionally rolled into transmission rates by public utilities. Nor will it be availing to rely upon sweeping declarations that the facilities for which rate base treatment is claimed are integrated into plans and operations to serve customers, without demonstrating exactly how that integration occurs, particularly where there is a challenge to the claimed rate base.

Here, the rate base will reflect changes as a result of Docket No. EL98-21-000, and specific rulings on credits below that will result in just and reasonable rates, without the necessity of "unscrambling the egg," as Staff was so loathe to do. However, in other cases it may be necessary to do exactly that -- unscramble the egg -- and to have stronger support for claims of integration in order to achieve the rate setting goals of the statutes the Commission is charged with implementing.

Michigan Systems' claims for credits are based upon Section 30.9 of the OATT, certain Commission policy statements interpreting that tariff language and relevant Commission decisional precedent. The underlying intent of this supporting rationale is that network customers owning transmission facilities that are <u>integrated</u> with the transmission provider's transmission system should receive a credit. While this seems clear, the Commission's definition of the word "integrated" is not as clear as perhaps it should be. Working with what we have, the following elements, derived from the sources cited above, would appear necessary to satisfy a claim for credit based on integration:

- the network customer must demonstrate that the facilities for which it seeks credit are integrated into the plans and operations of the transmission provider to serve its power and transmission customers.

- a key requirement of integration is that the transmission provider is able to provide transmission service to itself or other transmission customers over the network customer's facilities.

- actual use of a network customer's facilities by the transmission provider to provide service to the network customer or other parties.

· to be eligible for a credit, the network customer must not only demonstrate that its facilities are integrated into the plans and operations of the transmission provider to serve its power and transmission customers, but must also show that its facilities provide additional benefits to the transmission grid in terms of capability, reliability and are relied upon for coordinated operation of the grid.

The Commission has also provided guidance as to what will not satisfy the integration standard:

· interconnection of a network customer's facilities with those of the transmission provider alone is not enough to prove integration.

· the fact that the network customer's facilities serve a transmission function on the customer's side of the interconnection point is not enough to prove integration.

· the fact that a network customer's line constitutes a parallel path and is subject to parallel loop flows does not compel a conclusion that the line operates as part of an integrated network.

· unnecessary redundancy provided by a network customer's facilities cannot qualify for a credit.

Reviewing these elements against Michigan System's claims for credits, MS fails to demonstrate clearly and convincingly that the facilities for which it seeks credit, with the sole exception of the Airport Line, are integrated into CECo's transmission system in the manner contemplated by the Commission. The record shows an effort by Michigan Systems to convert transmission facilities, for the most part 69 kV or lower, that are essentially interconnected with those of CECo, but perform functions almost exclusively for the benefit of MS, into components of an integrated network, along with those of CECo. That effort, however, does not succeed. MS shows interconnection, redundancy, and some parallel paths and bi- lateral power flows, but does not convincingly demonstrate how its facilities, with the exception of the Airport Line discussed below, provide additional benefits to the grid in terms of capability and reliability. Moreover, it does not show that its facilities are relied upon by CECo for coordinated operation of the grid. CECo in fact denies a need for MCCP facilities to supply its own load and the load of other CECo transmission customers. All ten 138 kV interconnection systems between CECo and the MCP Integrated System were installed at the request of MCCP or its predecessors to receive power from the CECo system and those interconnections did not eliminate the need for new CECo facilities. Ex. CE-73 at 16. The studies of MS witness Reising show some bi-lateral power flows, which the witness concluded evidenced integration; however, the study fails to show persuasively that CECo relied upon those flows to serve its own load or the load of other transmission customers. Id. at 20.

The testimony of Staff's witness Smith provides further support for the conclusion that the MCCP facilities are not, with the exception of the Airport Line, integrated into the plans and operations of CECo to serve all of its power and transmission customers. Ex. S-30. Mr. Smith performed so-called MW-Mile studies on seven cases. In each, he analyzed flows to determine if the interconnection of MCCP facilities with those of CECo demonstrated evidence of integration. In all but one, the Airport-Livingston line, he concluded that the facility examined did not constitute a network facility and, therefore, was ineligible for a credit. MS is critical of the MW-Mile analysis because it contends that even a relatively large flow on the line will appear small when multiplied by the length of the line measured where such lines are not very long. MS I.B. at 45-6.

However, the methodology employed by Mr. Smith was not shown to be inappropriate [7], and the persuasiveness of Mr. Smith's testimony was not seriously challenged. I conclude that it may be relied upon in support of the CECo witness Erickson's similar conclusions, reached primarily via a different route.

The Airport Line, a 61 mile, 138 kV Wolverine transmission line operating between the Livingston substation to the Airport, has been identified by Staff witness Smith as potentially qualifying for a credit because, viewed along with CECo facilities, it forms a network facility. It is interconnected with CECo facilities at both ends and serves a network function. Ex. S-30 at 23. CECo argues that even this small part of the network customer facilities for which credit is claimed is ineligible because it was not planned jointly and provides no benefit to CECo at Livingston or Alpena. Staff has shown, however, that this 138 kV line is comparable to CECo facilities to which it is interconnected, and performs functions similar to those rate-based CECo facilities. MS is correct that it should receive credit for this line.

ISSUE 1 C -- Michigan Grid

Michigan Systems advocate the formation of a "Michigan Grid" that would include the transmission facilities of CECo, the MCCP members' facilities, and those of the Detroit Edison Company. A single transmission system that is coextensive with reasonable sales markets would encourage competitive sales markets, and for the same reason, would enhance electrical coordination and reliability, MS argues. MS I.B. at 89. MS urges the Commission to set transmission rates in recognition of the Michigan peninsular grid that exists and is used by CECo to its benefit.
This would be consistent with principles of comparability and open access, Michigan Systems argue. The Commission has the requisite authority, MS contends, to set rates in recognition of the fact that the economic transmission grid includes the facilities of multiple systems. Permian Basin Area Rate Cases, 390 U.S. 397 (1968). The Commission has authority to price on the basis of the entire grid to prevent discrimination, so it can certainly price transmission by considering the cost impacts of

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7 / The Commission has accepted this methodology for cost allocation purposes in a pool-wide transmission arrangement Mid-Continent Area Power Pool, 69 FERC ¶ 61,347 at 62,307 (1994); and for pricing transmission service in a pool-wide open access transmission service. Southwest Power Pool, Inc., 82 FERC ¶ 61,267 at 62,051-52 (1998).

systems that participate in forming the grid, MS argues. Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581 (1945). Michigan Systems maintain that such action would be consistent with the broad pro-competitive purposes of the Federal Power Act.

Formation of a "Michigan Grid" would curb CECo's effective operation of a unitary transmission system with Detroit Edison, to the exclusion of the smaller systems, MS contends. CECo refuses to recognize entitlements to credits, and excludes smaller systems' transmission in its definition of a grid for pricing purposes although it benefits from municipal and cooperative investments, but treats Detroit Edison's investment differently, MS argues. This is discrimination that cries out for remediation, according to Michigan Systems. MS I.B. at 92. Using this case to develop a "Michigan Grid" will help remediate this discrimination and fulfil the promise of Order No. 888, claims MS.

CECo contends that this MS proposal is outside the scope of the Commission's Orders setting this proceeding for hearing. Moreover, CECo argues that due process problems abound with the MS proposal, since interested third parties have had no notice that such a proposal might be considered in this proceeding. CECo argues that MS is attempting to transform a proceeding generated solely by a CECo tariff and service agreement filings into a proceeding to consider whether involuntary membership in an independent system operator arrangement should be mandated. Finally, CECo notes that it, along with Detroit Edison, has filed an accepted joint tariff as directed by Order No. 888 for power pools, which is available for parties desiring transmission service in situations where both CECo and Detroit Edison lie in the contract path.

Staff believes that Michigan Systems' attempt to create a "Michigan Grid" is inappropriate in this proceeding. This proceeding considers CECo's open access tariff for its own system. The proceeding was not established by the Commission to consider a proposal such as the one offered here by MS. Staff concludes that it is simply beyond the scope of this proceeding.

Ruling on Michigan Grid:

While Michigan Systems offer some sound arguments in support of the establishment of a "Michigan Grid" or other rational pooling of transmission systems, CECo and Staff are correct that the issue is outside the scope of the matters the Commission set for hearing in this proceeding. Moreover, the Company is also right that consideration of such a proposal here would create serious due process concerns. MS will have to wait for another opportunity to press its policy and discrimination issues. Its proposal for the establishment of a "Michigan Grid" for pricing transmission services is rejected.

ISSUE 1 D -- Voltage-Differentiated Rate Structure

ABATE offers evidence supporting the adoption of separate rates for service at or above 120 kV (bulk transmission) and below 120 kV (subtransmission). Ex. ABATE-1 at 5-9. ABATE argues that voltage-differentiated rates will more accurately track costs and provide more appropriate price signals to users of the transmission system. There is a logical point of separation between CECo's transmission and subtransmission systems based upon voltage levels, ABATE contends. CECo's transmission system includes bulk facilities at 120 kV or above, and subtransmission facilities generally ranging from 23 kV and 69 kV, which are designed to deliver power to the Company's distribution system from the bulk facilities. The subtransmission facilities are not used by all transmission customers, ABATE maintains, and should, therefore, be separately priced. If the revenue requirement was separated between bulk and subtransmission facilities, the subtransmission rate would only be paid by that system's users, which comports with the principle that costs of operating a system should be paid by those who use the system.

ABATE proposes a split of the Company's proposed $110 million revenue requirement where $43.6 million would be assigned to subtransmission and $59.8 million to bulk transmission, after removing $6.6 million for the cost of generator step-up transformers. Exs. ABATE-1 at 7; ABATE-3.

ABATE also points out that the Company's position has evolved to one which embraces voltage-differentiated rates in that it has proposed voltage-differentiated rates in connection with Michigan's Retail Open Access Program. ABATE I.B. at 6.

Staff notes that ABATE's proposal is consistent with the MPSC's actions, discussed above, which determined the jurisdictional split between distribution facilities and transmission facilities. That state agency determined that 46 kV facilities should be classified as distribution. Staff agrees with ABATE and recommends that facilities 120 kV and above be classified as bulk transmission facilities and those facilities at 46 kV and below as subtransmission facilities. Staff I.B. at 10.

Michigan Systems believe that ABATE's proposal has merit, but offers the view that an embedded cost, rolled-in rate may not be appropriate for charging customers connected to CECo's system at lower voltages. MS asserts that it may be more appropriate to develop the rates for customers connected at lower voltages on a direct assignment basis. They suggest that a second phase of this proceeding be established to determine whether low voltage rates should be developed on a rolled-in or direct assignment basis.

CECo's position is that, until the Commission grants its concurrence in Docket No. EL98-21-000 with the MPSC's Order in Case No. U-11283 approving a division between CECo's transmission and local distribution facilities, a single, rolled-in rate is appropriate. The Company contends that the rolling-in of transmission and subtransmission facilities has been approved previously, citing AES Power, Inc., 74 FERC ¶ 61,220 (1996), and Utah Power & Light Co., 14 FERC ¶ 61,162 at 61,296 (1981), among others.

Ruling on Voltage-Differentiated Rate Structure:

As noted above, the event that CECo was awaiting, Commission concurrence with the MPSC's Order, has occurred. The Commission has granted its concurrence with the MPSC's division between local distribution and transmission facilities, of which notice has been taken. Accordingly, ABATE's proposal to set voltage differentiated rates will be adopted. Further, Michigan System's point about the design of subtransmission rates is moot as it regards this Commission, due to the agency's concurrence with the jurisdictional split advocated by the MPSC in Docket No. EL98-21- 000.

ISSUE 1 E -- Generator Step-Up Transformers

Generator step-up transformers ("GSUs") are electrical devices that deliver power from lower voltages at the generation level to higher voltages at the transmission level. Ex. S-1 at 7. They are located at or near the generation facilities and are required because the voltage output from the generator is too low for efficient power transmission. Id. Consistent with Commission precedent prior to unbundling and recent decisions of Presiding Judges, CECo has included GSUs in its transmission rate base, and argues that it remains appropriate to do so, citing Minnesota Power & Light Co., 3 FERC ¶ 61,045 (1978) and Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 (1988).

Michigan Systems argue that GSUs are specifically related to the efficient and economic production of power and should not be included in the transmission rate base. MS contends that GSUs aid in the economic generation of power because, without GSUs, the output voltage of the generator would be too low for delivery of power to distant loads requiring that generating plants be located close to loads. Ex. MS-41 at 7; Ex. S-1 at 7. GSUs do not support the transmission function for the benefit of CECo's OATT and are not necessary for the operation of the transmission system, MS asserts. Moreover, according to Michigan Systems, CECo itself has argued, at the state level, that GSU-related costs more properly should be classified as production or generation costs. Ex. ABATE-16 at 7. The MPSC accepted CECo's argument that GSU costs are closely aligned with the generation function. In Re Consumers Power Co., Case No. U-11283 (MPSC Order filed January 14, 1998) at 16. CECo's witness Gaarde, in the instant proceeding, also admitted that many of CECo's GSUs should be reclassified as generation on a functional or operational basis. Tr. at 43, 45-48; Ex. MS-7.

Michigan Systems further contend that the Commission's Order No. 888 supports exclusion of GSU-related costs from the transmission rate base. Arguing that while the cases cited by CECo approve inclusion of GSU-related costs in transmission rates [8], MS maintains that those decisions predate the Commission's current approach to transmission pricing and its preference, stated in Order No. 888, for unbundled transmission rates. Michigan Systems point out that the Commission itself signaled the

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8 / Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 at 61,323 (1988); Minnesota Power & Light Co., 3 FERC ¶ 61,045 (1978).

possible need for reexamination of the so-called "bright line" historical approach to functionalization of costs between generation and transmission, and labeled GSUs as "the most likely candidates for refunctionalization." AES Power, Inc., 74 FERC ¶ 61,220 at 61,744 (1996), Order on Reh'g, 76 FERC ¶ 61,165 (1996); Northern States Power Co., 64 FERC ¶ 61,324 at 63,379 (1993), Order Denying Reh'g and Granting Clarification, 74 FERC ¶ 61,106 (1996).

Michigan Systems additionally argue that, by including GSU costs in transmission rates that are unrelated to a transmission customer's use of CECo's transmission system, it forces many transmission customers to pay for GSU-related costs twice. CECo's customers who desire to connect their own generating units to CECo's transmission lines would be required to install the necessary GSUs at their own expense, as well as to pay for the CECo GSUs in their transmission rates, MS contends. Ex. M-41 at 5. Because this "subsidization" is a one way street -- CECo does not contribute to the customers' GSU-related costs -- it runs afoul of the Commission's comparability standards, Michigan Systems argue.

MS proposes the removal of $75,200,856 from CECo's transmission rate base, which it contends is consistent with CECo's accounting-based calculation of its rate base. If any amount of GSU-related costs is to be removed from its rate base, CECo argues that the calculation should be done on a functional basis. CECo would exclude $45,552,808, less depreciation, on this basis. Staff calculates an amount close to the Company's proposal, $45,585,732.

Staff contends that CECo's position before the MPSC precludes it from arguing that GSUs are properly reflected in transmission rates. Noting that Consumers Energy advocated reclassification of GSUs to generation, and received a favorable state decision on its request, Staff claims that CECo cannot now seek to recover its GSU-related costs in its network and point- to-point transmission rates. Staff states that it is disingenuous of CECo to claim on the state level that its GSUs serve a production-function and at the same time argue before this Commission that such facilities serve a transmission function. Staff I.B. at 13.

Staff further maintains that the unbundling requirements of Order No. 888 preclude the continued rolling of GSU-related costs into unbundled open access transmission rates. Staff admits that the Commission is not there yet and that, historically, GSU's have been rolled in with other transmission facilities for allocation purposes. For its historical context, Staff cites, among other cases, Minnesota Power & Light Co., 3 FERC ¶ 61,045 at 61,137 (1978); Otter Tail Power Co., 12 FERC ¶ 61,169 at 61,421 (1980); and New York State Electric & Gas Corp., 37 FERC ¶ 61,151 at 61,366 (1986). Staff claims that GSU cost allocations were not critically examined in an era when bundled generation and transmission services or full requirements service predominated. With the development of a competitive bulk power supply under open access transmission, the potential for cross- subsidization caused by misclassification of costs has obviously increased, Staff argues. Staff goes on to point out that the Commission, in the Northern States case, observed that refunctionalization of

GSU-related costs to production would require the corresponding development of a separately stated reactive power charge. But now, Staff observes, the Commission mandates the use of a similar charge for one of the six ancillary services required under Order No. 888. Staff I.B. at 15. In the new competitive markets fostered by Order No. 888, the development of accurate and timely prices for the component parts of previously bundled services is necessary, Staff argues, for customers to receive the correct price signals so that they may select the best options available to them.

Staff further maintains that a transmission customer that pays for and imports power having an efficient transmission level voltage into a given control area is competitively disadvantaged if it must pay a base transmission rate that includes the separate and redundant (to the customer) GSU-related costs, particularly considering that the purpose of the GSUs is to increase the voltage of the control area operator's own generation. The situation is aggravated, Staff contends, because the native generation effectively receives a subsidy by having a portion of its GSU-related costs borne by the competing imported power provider. This would violate one of the basic tenets of Order No. 888, Staff claims, namely, that the transmission provider take service on the same terms and conditions that it offers to others. Id. at 17, citing Order No. 888 at 31,743, n.452; Order No. 888-A at 30,271, n.277.

Notwithstanding the fact that the Commission has signaled the likely candidacy of GSU-related costs for refunctionalization, and the importance of completing the comparability and unbundling picture so that accurate price signals are set for all aspects of an efficient competitive power market, Staff notes that Presiding Judges have, up to date, declined its request to reconsider GSU treatment. See Florida Power & Light Co., 73 FERC ¶ 63,018 at 65,199 (1995) (pending on exceptions) (where the Presiding Judge found that GSUs are tangential or ancillary to transmission service and both decrease losses and improve the reliability of transmission service); Maine Public Service Co., 74 FERC ¶ 63,011 at 65,018 (1996)(pending on exceptions at the time of the briefs, but since decided) (where the Presiding Judge found that the GSUs could not easily be allocated to specific portions of the system or to specific services in the absence of specific engineering testimony); Kentucky Utilities Co., 75 FERC ¶ 63,024 at 65,091 (1996)(pending on exceptions at the time of briefs, but now decided) (where the Presiding Judge rejected Staff's position without prejudice to its making a detailed showing in a future case of the propriety of classifying GSU costs to production); Northern Indiana Public Service Co., 79 FERC ¶ 63,009 at 65,102- 103 (1997)(pending on exceptions) (where the Presiding Judge relied upon earlier Commission precedent and found that Order No. 888 did not change Commission policy); American Electric Power Co., 80 FERC ¶ 63,006 at 65,056 (1997)(pending on exceptions) (where the Presiding Judge acknowledged Staff and intervenor arguments but found that they had not shown that unbundling converted a transmission function into a generation function); and Niagara Mohawk Power Corp., 82 FERC ¶ 63,018 at 65,133-35 (1998)(pending on exceptions) (where the Presiding Judge was sympathetic to Staff's position and would have recommended it, had the slate been clean, but declined to do so because the Commission had spoken on the subject and had the opportunity, with five initial decisions pending, to change its position).

ABATE agrees with Staff and Michigan Systems that GSUs should be classified as generation-related facilities on grounds of cost causation and fairness. Only transmission customers who purchase their power from CECo actually make use of the Company's GSUs, ABATE argues. ABATE contends that CECo realizes a competitive advantage over independent power producers by inclusion of GSU costs in transmission rates, because the independent producers must pay for the cost of their own GSUs. ABATE presses for a $6.6 million reduction in CECo's transmission revenue requirement to reflect the assignment of GSU-related costs to generation instead of transmission.

Ruling on Generator Step-Up Transformers:

This case is different in at least one respect from the pending proceedings where this issue has been raised. Here, there is evidence that the Company argued successfully before the MPSC that GSUs should be classified as generation plant and sought to have the State Commission's determinations adopted by this Commission as well, in Docket No. EL98-21-000. By Letter Order issued July 29, 1998, the Commission declined to adopt the MPSC's reclassification of facilities from transmission to production because the scope of that proceeding was limited to the classification of facilities between transmission and local distribution. [9] Nevertheless, the Company's admissions in the context of the Michigan proceeding and its request before this Commission for a declaratory order adopting a reclassification of GSUs from transmission to generation cannot be ignored in the setting of transmission rates in the instant proceeding. There is, indeed, some disingenuity on the Company's part in continuing to advocate assignment of its GSU-related costs to the transmission function in this proceeding, while advancing contrary positions in the Michigan state proceeding and in Docket No. EL98-21-000.

Of course, the Company's position regarding the proper classification of GSUs in the state proceeding and the MPSC's determination, which has not been adopted by this Commission, are not fully dispositive of the matter before us. Here, Staff and MS have urged that the GSU classification issue be reexamined in light of Order No. 888's requirements for comparability and mandatory unbundling of production, transmission and ancillary services. What Staff, MS and ABATE argue is that the Commission's Order No. 888 provides a valid opportunity for reexaming this issue because the Commission, in that Order, changed the construct of its earlier decisions, which were made when generation and transmission services were bundled and where the classification issue regarding GSUs was not of critical significance. This argument is convincing on this record and in the circumstances of this proceeding. Placing the issue of proper classification of GSU-related costs in the current regime of unbundled services designed to facilitate bulk power supply competition through open access transmission service, it is quite clear that GSU-related costs must be removed from

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9 / As noted, the Commission adopted the MPSC's findings that certain facilities identified in the pleadings are State- jurisdictional local distribution facilities and others, identified there, are Commission-jurisdictional transmission facilities.

transmission rate base. To do otherwise would impede in two ways the Order No. 888's goal of allowing non-traditional generators to access the transmission grid on a non-discriminatory basis: first, by charging transmission users rates that include costs for services not required by the transmission customer, and, second, by subsidizing the transmission owner's generation by inclusion of its GSU costs in transmission rates paid by competitors.

The rate treatment advocated by CECo would violate one of the basic principles of Order No. 888, i.e., that the transmission provider take services on the same terms and conditions it offers to others. The violation occurs because, under the existing scheme, the transmission provider's GSU transformer costs are recovered in its transmission rates, which is a subsidy unavailable to competitive generators who must pay their own GSU transformer costs.

While the case for the position advocated by MS, Staff and ABATE is strong enough to prevail as argued on this record, it is important to note that the Commission's recent decisions in Kentucky Utilities Co., 85 FERC ¶ 61,274 (November 25, 1998) and Maine Public Service Co., 85 FERC ¶ 61,412 (December 22, 1998), removes all doubt as to the proper outcome. In Kentucky Utilities Co., the Commission reexamined its previous policy on the functionalization and recovery of costs associated with GSUs to ensure that customers of unbundled services pay only their appropriate share of the cost of services that they use. Noting that much had changed since it decided the line of cases where the costs of GSUs were included in basic transmission rates, the Commission, largely for the reasons offered here by Staff, MS, and ABATE, concluded that the costs of a GSU transformer should be directly assigned to its related generating unit. Because GSUs are used in the provision of both generation and ancillary services, the Commission found that the costs of these facilities should be charged to customers using those services, and not to customers of transmission service. The decision in Maine Public Service Co. is in accord. Accordingly, I conclude that GSU transformer costs should be removed from the transmission rate base. [10]

The amount that should be deleted from transmission rate base is also contested. CECo believes the reduction should be no more than $30,197,719, after deducting depreciation reserves. Its witness Gaarde calculated this figure based upon an operational or functional analysis of recent GSU data. Ex. CE-55 at 2-3. ABATE argues for a revenue requirement deduction of $6.6 million for this purpose. Ex. ABATE-1 at 3-5,7. Staff's number is close to the Company's, namely $46,552,808, less $16,000,000 depreciation reserve, or $30,552,808. Ex. S-1 at 10. Michigan Systems would remove $75,200,856, less $27,915,688 in depreciation reserves, or $47,285,168. MS bases its proposal on an historical accounting basis, removing the entire original investment in GSUs.

Because the Company's transmission rate base is based upon historical original

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10 / CECo should be allowed to revise its ancillary service rates to include appropriate GSU transformer costs in the derivation of those rates.

costs, items should be removed from rate base using the same methodology. It would be mixing apples and oranges to remove items from rate base using a functional or operational analysis when the rate base itself was calculated on an historical accounting basis. MS' position is more persuasive and is thus adopted.

ISSUE 1 F -- Dedicated Line and Substation Investment

Michigan Systems argue that CECo has included in its proposed transmission rate base facilities that generally play no role in serving the transmission needs of customers like MS. These include radial lines and substations dedicated to specific customers. According to MS, these lines are not used to provide service under the OATT. Ex. MS-41 at 8-9. MS therefore proposes to remove $21,851,694 worth of original plant investment, less $6,704,399 in depreciation. Id. at 9; see also Ex. MS-45.

CECo refers to what it describes as the Commission's long- held preference for rolled-in pricing in support of inclusion of radial lines in its transmission rate base, citing Detroit Edison Co., 54 FPC 3012 at 3020 (1975); Public Service Co. of Indiana, 56 FPC 3003 at 3034-36 (1976); and AES Power, Inc., 74 FERC ¶ 61,220 at 61,744 (1996). CECo contends that it is a basic truism that most transmission customers on an integrated system do not generally use all of the features of each system that are important to the reliability of the service. Niagara Mohawk Power Corp., 42 FERC ¶ 61,143 at 61,530 (1988). That certain customers might not use some parts of an integrated system is not a valid reason to depart from rolled-in pricing, CECo argues.

Ruling on Dedicated Line and Substation Investment:

The dedicated lines and substation investment should not be included in the transmission rate base for the same reasons that govern the ruling on Voltage-Differentiated Rates. These facilities will be included in the subtransmission category, per the Commission's adoption of the Company's proposal in Docket No. EL98-21-000.

ISSUE 2 A -- Rate of Return

To begin, there is no disagreement among the parties on the following elements of the rate of return calculation: the appropriate capital structure, cost of long-term debt or the cost of preferred stock. The agreed-upon elements are:

Element	Amount (000)	Ratio	Cost
Long Term Debt	$2,034,171	49.09 %	7.29 %
Prefer'd Stock	$ 354,726	8.56 %	7.80 %
Common Equity	$1,755,074	42.35 %	-

TOTAL	$4,143,971	100.00 %	-

However, CECo and Staff disagree upon what the authorized return on common equity should be. The Company presented the testimony of Mr. Ernst, its Director of Rates, in support of its requested authorized return on common equity of 12.25 percent. Exs. CE-25 at 41-61; CE-59 at 22-28; CE-112.

CECo, a wholly owned subsidiary of CMS Energy Company, does not have publicly traded common stock. Accordingly, Mr. Ernst first selected a group of proxy companies, which he determined were comparable, as a group, to CECo's operations. Ex. CE-25 at 44. Mr. Ernst used the Discounted Cash Flow ("DCF") methodology in developing his recommended return on equity. He used the Capital Asset Pricing Model ("CAPM") as a check upon the reasonableness of the results obtained via the DCF approach.

Mr. Ernst testified that two principal factors affect the risks perceived by investors: business risk, which encompasses all of the risks of a firm as if it were financed entirely by common equity, and financial risk, which is the risk added by issuance of debt and preferred stock. Mr. Ernst testified that business risk was increasing for electric utilities in general, and for CECo in particular. Ex. CE-59 at 27-28; Tr. at 708.
He found that a return of 12.25 percent would fairly and reasonably compensate investors for the overall risk incurred by an investment in CECo, assure confidence in the financial integrity of the Company, and allow the Company to maintain and support its credit and attract capital, thereby satisfying the standards of Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia, 262 U.S. 679 (1923), that equity investors are entitled to earnings commensurate with other investments of comparable risk, and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944), that a return should be set at an appropriate level such that a utility can maintain and support its credit and attract capital.

Staff presented the testimony of its expert, Mr. Green, who, like CECo's witness Mr. Ernst, used the DCF method that has been long approved by the Commission. Staff's witness, however, employed a different proxy group than Mr. Ernst and different inputs into the DCF formula to reach a recommended return on equity of 9.4 percent. Exs. S-38; S-25.

Michigan Systems argue that the return requested by CECo is too high because it reflects risks of an electric company engaged in activities in addition to the provision of electric transmission service. MS contends that it would be appropriate to set the Company's return as if it were a stand-alone transmission company, given the Commission's encouragement of unbundling and electric industry restructuring in its Order No. 888. It argues that the rate of return for CECo's transmission service should reflect the lower risks associated with the provision of monopoly transmission service. MS I.B. at 106, citing Northwest Pipeline Corp., 79 FERC ¶ 61,309 at 62,381 (1997). Further, MS critiques CECo's DCF analysis, for much the same reasons advanced by Staff.[11]

11 / Michigan Systems' arguments on DCF issues mainly agree with Staff's.

The differences between the approaches of the Company and Staff's witnesses lie in three areas: (1) the appropriate proxy or comparable group to use in determining the return on equity for CECo; (2) the appropriate growth rates to be used in the DCF formula; and (3) the appropriate dividend yields to use in the DCF formula.

1. Proxy Group

In selecting proxy companies, CECo's witness focused attention on electric companies whose business was primarily electric operations. The criteria employed were historical information on (1) bond ratings; (2) equity ratio; (3) net plant size; and (4) geographic location. Ex. CE-25 at 45.

For bond ratings, which measure a utility's default risk, Mr. Ernst selected a range of A1/A+ to Baa2/BBB. At the time of his testimony, CECo's bond rating was Baa3/BBB+. Ex. CE-112 at 9. As for equity ratio, Mr. Ernst used Regulatory Research Associates' "Industry Study, July 1, 1997, Electric Utility Quality Measures" (Ex. CE-90) to develop a range for this selection criterion of between 36 percent and 46 percent, which is a plus or minus 5 percent range around CECo's 41 percent equity ratio. For plant size, Mr. Ernst selected companies with net plant between $1 billion and $8 billion. CECo has a net plant investment of $4.5 billion. He also limited the geographic location to utilities in the Midwest and Mid-Atlantic areas to find utilities operating under comparable meteorological conditions.

Mr. Ernst selected the following proxy group of five companies to perform his analysis:

- Atlantic Energy, Inc.
- Delmarva Power & Light Company
- Illinova Corporation
- Minnesota Power & Light Company, and
- PP&L Resources, Inc.

Ex. CE-54 at 15.

Staff's witness was critical of the inclusion of companies (Atlantic Energy and Delmarva Power & Light) with a merger in progress. Also, Staff condemns the Company for failing to include in the proxy group CECo's parent, CMS Energy, since CECo accounts for most of CMS Energy's revenues. Staff further argues that geographic considerations have not been justified as a selection criteria.

Staff's witness Green used CMS Energy as a proxy for CECo and determined his proxy group by looking at companies comparable to CMS Energy. The three companies selected by Mr. Green were Illinova Corporation, Rochester Gas and Electric and Eastern Utilities

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Accordingly, while these arguments have been considered, they are not separately discussed herein.

Associates. His criteria for selection included similar bond ratings, similar safety ratings from Value Line Investment Survey, similar operational risks and similar operational safety and cost risks. Finally, he excluded companies with merger activity within the six months of data that he employed. Exs. S-25 at 8-10; S-26 at Schedule 5; Tr. at 1792.

CECo contends that Staff's focus on companies that were comparable to CMS Energy is misplaced in that it does not give proper emphasis to the electric business. The goal, according to CECo, should be to select a group of companies comparable to the jurisdictional company whose rates are being set by the Commission. Because the proxy group selected by Staff's witness Green is heavily influenced by combination gas and electric companies, insufficient emphasis is placed on electric operations, CECo maintains.

The Company also argues that Staff's proxy group is too small, consisting as it does of only three companies. CECo also argues that Staff's witness, in testimony in another case, Docket No. SC97-2-000 involving El Paso Electric Company, used a selection criterion that gave greater weight to companies with a high percentage of revenues from electric operations than he did in this case. Exs. CE-107; CE-108; CE-109. Mr. Green also inappropriately excluded Entergy Corporation ("Entergy") from his proxy group, CECo argues, because its percentage of electric revenues to total revenues is 90.05 percent, just outside his established bounds of 30 to 90 percent, while he includes Eastern Utilities Associates, whose ratio is 89.3 percent. Inclusion of Entergy would raise the return recommendation, claims CECo.

CECo further contends that the Staff witness' proxy group is not comparable to CMS Energy in terms of internal growth rate, retention rate and earned return on equity, so that the group could not provide a meaningful indication of investor expectations of CMS Energy. Ex. CE-60. Moreover, CECo maintains, two of Mr. Green's three companies are not comparable to CECo and should have been excluded. Rochester Gas & Electric does not meet the equity ratio criterion determined as appropriate for comparative purposes by CECo's Mr. Ernst, and Eastern Utilities Associates fails to meet the CECo witness' net plant size and geographic criteria. Staff also failed to use equity ratio as a selection criterion, which CECo contends results in inadequate attention to financial risk as a selection factor.

CECo also sees as inapt the comparison of Rochester Gas and Electric with CMS Energy, claiming that the latter has high expected growth, whereas the former is perceived by investors as having low growth potential. Moreover, the Staff witness' exclusion of companies involved with mergers was inappropriate, says CECo, because the markets can be expected to self-correct stock prices for merger participants, returning to normal levels within 60 days of a merger announcement. Tr. at 569-71. Finally, CECo argues that Staff should not have used CMS Energy as a proxy for CECo because, even though 87 percent of CMS Energy's revenues derive from CECo, the Company's electric operations account for only 56 percent of its revenues. It is therefore inappropriate, the Company contends, to view CMS Energy as a proxy for CECo's electric business.

Ruling on Proxy Group:

The Company has the better proxy group. Staff's use of CMS Energy as a proxy may seem intuitively right. However, if one is attempting to set a return for CECo's electric operations, as we are here, inclusion of CMS Energy as a proxy carries the baggage of that holding company's other operations, and, as argued by CECo, includes CECo's significant non-electric business, as well. Staff is then left with a three company proxy group, including one combination company, Rochester Gas & Electric, with significant non-electric revenues and with an equity ratio unlike CECo's, and another, Eastern Utilities Associates, whose plant is about one-fifth the size of CECo, and which operates in New England, where climate and meteorological conditions are different from the Midwest where CECo operates.[12] Nor has Staff offered convincing criticisms of the Company's proxy group proposal. Contrary to Staff's argument otherwise, it has been shown that equity ratio is an important selection criterion. Ex. CE-25 at 43. Moreover, inclusion of merger partners in CECo's proxy group is not fatal for the reasons suggested by CECo. CECo R.B. at 39-40. For the above reasons, the proxy group proposal of CECo will be used for further analysis.

2. Growth rates in the DCF formula

The Commission has expressed a preference for use of a two- stage model for determining growth rates in gas pipeline cases. In the two-stage approach the Commission has used in recent cases, growth rate projections for a five-year period were averaged with longer term growth rate projections. Northwest Pipeline Corp., 79 FERC ¶ 61,309(1997); Williston Basin Interstate Pipeline Co., 79 FERC ¶ 61,311 (1997). Most recently (at the time of this decision), the Commission has revised the equal weighting used in the averaging of short and long term growth rates in those cases and now prefers to give two-thirds weight to the short term growth rate and one-third weight to the longer term growth rate. Transcontinental Gas Pipe Line Corp., 84 FERC ¶ 61,084, Docket Nos. RP95-197-032 and RP96-44-008 (Phase I) and Docket Nos. RP95-197-031 and RP97-197-024, and RP96-44-007, Order on Reh'g (July 29, 1998); Williams Natural Gas Co., 84 FERC ¶ 61,080, Docket No. RP93-109-012, Order Granting Reh'g in Part (July 29, 1998). This revision in its two-stage model was made to reflect the greater reliability of the short term projections, while continuing to give some weight to long term growth projections, which the Commission continues to believe warrant recognition. The Commission, however, has not established a preferred approach for electric utility cases.

CECo's witness Ernst calculated growth rates for his proxy companies using a traditional approach and a two-stage approach. In calculating the growth rates using a traditional approach, Mr. Ernst reviewed investment analysts' calculations of growth rates, equally weighting the growth projections of Value Line Investment Survey ("Value Line") and Institutional Brokers Estimate System ("IBES") in order to normalize growth expectations. Ex. CE-25 at 52. The resulting calculation of the average growth rate for the proxy companies is 4.36 percent. Ex. CE-54 at 4.

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12 / Staff's third proxy company, Illinova Corporation, is among the five in CECo's proxy group.

Mr. Ernst's two-stage growth rate averaged the results of his traditional analysis for the short term growth rate and, for the long term rate, the simple average of the Wharton Economic Forecasting Associates ("WEFA") forecast of the Gross Domestic Product ("GDP") for the years 2003-2015 under the low growth scenario. Ex. CE-25 at 53. This resulted in an average growth rate for the proxy companies of 4.42 percent. However, the Company has accepted Staff witness Green's updated average GDP growth rate of 4.97 percent projected by the Energy Information Administration ("EIA"), DRI/McGraw Hill and WEFA for the period beginning 2002. Ex. S-40 at 22; CECo I.B. at 39-40. Averaging this long term rate with its short term rate resulted in a two- stage growth rate of 4.67 percent. Inclusion of this updated, higher growth rate in its return calculation increased the cost of equity above the number in the Company's return exhibit from 12.27 to 12.53 percent and the midpoint from 12.23 percent to 12.48 percent. CECo I.B. at 39. This, the Company argues, provides further support for its 12.25 percent return request.

Staff's witness Green claimed to have followed the same methodology that the Commission employed in Northwest, 79 FERC at 62,384 and Williston Basin, 79 FERC at 62,390. He combined a five-year growth rate published by IBES with a long term growth rate to arrive at a single growth rate. However, instead of using the GDP forecast for the long term rate as the Commission did in the cited cases, he used DRI data showing the electric industry's return on capital. He believes this approach better reflects the expectations of investors for the future growth in earnings for the electric industry. Ex. S-25 at 12-19. Mr. Green explained that the long term GDP forecast of 5.06 percent [13] is inappropriate for electric companies, which, according to Value Line, are expected to provide returns in the range of 2.66 to 3.81 percent over the 1997-2001 time frame. Id. at 15. According to Mr. Green, there is no evidence that the electric industry growth rate will increase 125 basis points between 2001 and 2002 and sustain that level through 2020. Accordingly, he used the DRI long term forecast of return on capital for the electric industry, adjusted for company-specific information on the estimated increase in the number of shares, to obtain an estimate of growth in earnings per share. Id. at 18. Averaging the short term IBES growth rate for CMS Energy with the long term share-adjusted DRI growth in return on capital resulted in a recommended growth rate of 5.9 percent for CMS Energy. This, combined with the high and low dividend yields, resulted in a range of recommended returns for CMS Energy of 9.14 to 9.87 percent. The same model applied to the Staff proxy group produced a range of returns of 9.55 to 11.52 percent in Mr. Green's original testimony and 8.79 to 10.77 percent in his updated testimony. Exs. S-26 at Schedule 24; S-39 at Schedule 18. Averaging the results for CMS Energy and the proxy group resulted in a range between 9.35 and 10.69 percent. Mr. Green's recommendation is for a return on equity of 9.4 percent, the rounded mid-point of this range. Staff I.B. at 39.

Staff is critical of Mr. Ernst's growth rate in several respects. First, Staff argues that Mr. Ernst, by averaging a traditional DCF growth rate analysis that used only short term data with a two-stage analysis of short and long term data, gives insufficient weight to the long term projection. Staff contends that this is inconsistent with the Commission's two-stage approach as applied in Northwest and Williston Basin. Second, Staff points out that Mr. Ernst did not use only IBES data for his short term forecast, averaging IBES and Value Line data instead.

13 / Obtained by averaging estimates of growth in GDP provided by DRI, EIA and WEFA, as the Commission preferred in Northwest and Williston Basin.

Because Value Line uses historical data, Staff argues that its use is inconsistent with the Commission's preference for forward-looking growth rates. Staff maintains that the Company could have used Zacks, another forward-looking projection source, if it wished to average two sources for this component of the return formula. Staff R.B. at 17. Third, Staff contends that Mr. Ernst further departed from Commission precedent when he used a twelve-year WEFA GDP forecast, instead of the 20 years used by the Commission. Fourth, Staff maintains that, by accepting Staff's updated GDP growth rate, CECo is cherry-picking a high, updated GDP growth rate and combining it inappropriately with stale dividend yield numbers.

CECo, meanwhile, also criticizes Mr. Green's growth rate calculation methodology as inconsistent with Commission precedent in that it does not employ a GDP forecast to derive a long term growth component for the two-stage analysis. CECo argues that Staff's recommended DRI return on capital rate is not an appropriate measure of long term growth expectations because investors do not use the DRI forecast for this purpose and because the GDP more closely matches expected growth in earnings. Ex. CE-59 at 9; Tr. at 703. Further, CECo argues, the DRI return on capital projections does not reflect investor expectations of growth in either dividends or earnings and cannot properly be used as a surrogate for growth in earnings. Ex. CE-59 at 9; Tr. at 658, 1753-4. CECo also points out that the return on capital rate included debt, which is not appropriate to an analysis of growth, and contains an inappropriate assumption of negative growth. CECo R.B. at 54-58.

Ruling on Growth Rate:

Both Staff and CECo have demonstrated the dangers inherent in a departure from soundly reasoned precedent in an attempt to find greater precision. Abandonment of the compass provided by Commission precedent in a search for greater precision often results in journeys through unchartered territory that lead away from one's objective. CECo is correct that Staff's use of the DRI return on capital projections is an unwise departure from the GDP forecast preferred by the Commission for the long term growth component of the two-stage return analysis. While Staff was searching for a forecast that it deemed more appropriate for the electric industry than the GDP forecast used principally in the context of gas pipelines, it ignores other evidence in the case which suggests that an electric company that offers, among other things, unbundled open access electric transmission and related services and a gas pipeline company that offers unbundled gas transmission and related services have much in common.

In the restructuring of the unbundled electric industry encouraged by the Commission's Order No. 888, the electric business of the future will not look very much like the electric industry of the past, making projections of returns on capital predicated on historical assumptions an unlikely source for a true measure of expected long term growth. The record does not explore the return implications of a new industry structure in any depth, beyond Michigan Systems' argument that the return should be set as if the Company was a transmission only entity. There is much to commend the position of Michigan Systems. Unfortunately, its argument was not developed sufficiently on this record to allow for more than an encouragement that its theory be pursued in subsequent proceedings.

In these circumstances, the wisest course is to follow precedent where such precedent has not been shown to be clearly inapposite. The Commission has expressed a preference for use of GDP projections to measure long term growth for gas pipelines. Such pipelines have much in common with an electric company offering open access transmission service, the rates for which this proceeding has been set to establish. Accordingly, the GDP projections of DRI/McGraw Hill, WEFA and EIA will be used for the long term growth component of a two-stage growth rate calculation. The updated growth rate offered by Staff on this basis is 4.97 percent, a value which the Company accepts.

There is also no good reason to depart from the Commission's preference in selecting an appropriate short term growth rate component. The Commission has preferred use of the short term (5-year) growth rate published by IBES. Staff is correct that there is no reason to add Value Line projections, as CECo's witness did, where the IBES data has Commission acceptance and has not been shown to be inappropriate in this case.

Accordingly, the short term growth rate for the proxy companies will be set using only the IBES data, as recommended by Staff. To be consistent with the use of an updated value for the GDP long term component, more recent IBES figures offered by Staff will be employed. Ex. S-56, Column entitled: "Current IBES 5 Year EPS Growth Estimate" (2/19/98).

3. Dividend Yield

The current dividend yield for the CECo proxy group of companies was calculated by determining the closing stock price for each day over six months and calculating an average closing price over the six months. The quarterly dividend used to complete the calculation was the latest recorded dividend from the Value Line Survey at the time of the study. Ex. CE-25 at 49- 50. This quarterly amount was annualized by multiplying by four. Monthly yield calculations were then performed for each company by dividing the annualized dividend by the average stock price for each month. The dividend yields, adjusted to reflect that dividends are paid quarterly, are depicted in Exhibit CE-54 at 2.

Staff, however, has demonstrated that the dividend yields computed by the Company and depicted in Exhibit CE-54 may be unrepresentative of more recent trends. Tr. at 598-608; see Exs. S-48; S-49; S-50. In these circumstances, and to be consistent with the updating of the GDP and IBES data employed in the two- stage growth rate determination, more current yield figures than are contained in Exhibit C-54 should be analyzed in determining the appropriate dividend yield for the Company's proxy group to be used in computing the DCF formula. Staff's Exhibit S-48 provides yields for the month ending September, 1997, and Exhibit S-58 shows dividend yields for the Company's proxy group companies in a report dated December 12, 1997. Both of these more current sources depict dividend yields generally below the March, 1997 to August, 1997 average yield figures calculated by Mr. Ernst at the time of his testimony. Mr. Ernst's approach to the computation is sound, and, if more current figures were available, it would be sufficient. However, it would be wrong to ignore the more recent trend, particularly where other related components of the DCF calculation have been updated. Therefore, the following data will be employed to arrive at the appropriate dividend yield for the proxy group companies to be used in calculating the DCF return:

Company	Yield in Ex. CE-54	Yield in Ex. S-48	Yield in Ex. S-58
Atlantic Engy.	9.20 %	8.59 %	7.7 %
Delmarva	8.58 %	8.16 %	7.3 %
Illinova	5.55 %	5.77 %	4.6 %
Minn. Power	6.87 %	5.64 %	4.6 %
PP&L Resources	8.24 %	7.63 %	7.3 %

Ruling on Dividend Yield:

In order to obtain dividend yields that reflect more current conditions than those offered by Mr. Ernst at the beginning of this proceeding, composite dividend yield figures will be developed by averaging all three dividend yield sources in the record. The results are as follows:

Atlantic Energy, Inc.......................8.50 %
Delmarva Power Company.....................8.01 %
Illinova Corporation.......................5.31 %

Minnesota Power & Light Company............5.70 %
PP&L Resources, Inc........................7.72 %

4. Calculation of the Return on Equity

As noted above, Mr. Ernst averaged the results of a traditional growth approach with those of a two-stage growth approach as a means of giving greater weight to short term growth forecasts, which he concluded investors tend to do. The Commission itself concluded that greater weight should be given to short term growth forecasts in its two-stage model in its Orders on Rehearing in Transcontinental and Williams, to give recognition to the greater reliability of short term forecasts. The Commission, however, simply weighted the short term growth forecast by two-thirds and the long term growth forecast by one- third to achieve what it considered a proper balance.

CECo also prefers use of an average to calculate where within the range of reasonableness the actual allowed return on equity should lie. CECo observes that the Commission in the recent gas pipeline cases has indicated that it will choose a return from the lowest, the midpoint or the highest of the returns calculated in the proxy group, depending upon its assessment of the pipeline's risk or other special circumstances. The Company further notes that no policy has been established for jurisdictional electric companies. Use of an average is argued to be more representative for an electric company said to be of average risk. CECo I.B. at 41-2.

The Company argues that its recommended return of 12.25 percent is conservative because CECo has greater financial risk than the proxy companies as indicated by its lower equity ratio. If this risk factor had been considered and the high end of the range of reasonableness had been deemed appropriate to recognize this risk, CECo contends that a return of 13.0 percent would have resulted. Id. at 44.

Finally, while the Company's return witness, Mr. Ernst, also offered a Capital Asset Pricing Model ("CAPM") analysis, he did not base his recommendation on that approach, but used it to test the reasonableness of his primary 12.25 percent return on equity recommendation. The CAPM approach resulted in a calculation of a required return ranging from 11.75 to 13.20 percent, with an average of 12.12 percent and a midpoint of 12.48 percent. Ex. CE-54 at 12. Mr. Ernst saw the CAPM model as a reasonable method to check the reasonableness of any DCF analysis. Ex. CE-59 at 23.

Staff concludes that a DCF analysis consistent with the Commission's requirements in Northwest and Williston Basin, adjusted to include a growth rate specific to the electric industry and the most current dividend yields, and employing its recommended proxy group, is the correct approach to be followed here. Staff's witness Green testified that the use of the CAPM approach is not appropriate to determine a rate of return. He questioned both the model itself and the components that CECo's witness Ernst entered into the model, contending that the risk- free rate Mr. Ernst used was not in fact risk free, that Mr. Ernst's use of betas, which measure the market risk of a security, was improper, and that the witness' use of a 71-year historical analysis of stock returns to determine the risk premium was inappropriate.

Ruling on Calculation of the Return on Equity:

The proper approach to determine a rate of return on common equity in this instance is a DCF analysis consistent with the Commission's policy determinations in Northwest and Williston Basin, as modified and clarified in the Commission's Orders on Rehearing in Transcontinental and Williams. While both Staff and CECo claim to have followed the most recent Commission determinations on rate of return at the time of their testimony here, both made departures from the Commission's methodology that have not been well supported, for the reasons discussed. The two-stage growth rate methodology and the weighting suggested in the Commission's most recent return pronouncements is preferable to the weighting suggested by either the Company or Staff. The Commission's two-stage methodology is a cleaner approach than the one suggested by CECo in that it does not introduce a wholly new forecast, such as the one CECo advances here as a "traditional" growth calculation. In addition, providing greater emphasis on short term projections because of their reliability, as the Commission did in the Rehearing Orders in Transcontinental and Williams, is preferable to the equal weighting proposed by Staff. [14]

The approach that will be adopted here to determine the appropriate return on equity is the DCF methodology, employing a two-stage growth rate determination, weighting by two-thirds the more current IBES short term growth projection and by one-third the GDP long term forecast, the latter measured by averaging the EIA, WEFA and DRI/McGraw Hill projections as updated by Staff. The proxy group will be the one proposed by Mr. Ernst, CECo's witness, for the reasons discussed above. The composite, unadjusted dividend yields as determined above will be employed and adjusted for dividend growth.

14 / Staff, of course, did not have the benefit of the Commission's decisions in Transcontinental and Williams when it offered its testimony here.

The results are as follows:

Company	Long Term Growth [15]	Sht. Term Growth [16]	Weighted Growth [17]	Adjusted Yield [18]	Cost Rate [19]
Atlantic Energy	4.97 %	2.0 %	2.99 %	8.63 %	11.62 %
Delmarva Power	4.97 %	3.5 %	3.99 %	8.17 %	12.16 %
Illinova Corp.	4.97 %	5.1 %	5.06 %	5.44 %	10.50 %
Minnesota Power	4.97 %	4.37 %	4.57 %	5.83 %	10.40 %
PP&L Resources	4.97 %	2.31 %	3.20 %	7.84 %	11.04 %

In conclusion, a return on equity in the range of 10.40 to 12.16 percent has been justified on this record. The return within that range most appropriate for CECo is 11.04 percent, the median of the range of reasonableness, because no special circumstances have been demonstrated on this record that would justify selection of the low or high end of the indicated range. Transcontinental Gas Pipe Line Corp., 84 FERC ¶ 61,084, Order on Reh'g (July 29, 1998).

ISSUE 2 B -- Materials and Supplies and Prepayment Components of Working Capital

Michigan Systems claim that CECo has overstated the Working Capital allowance for Materials and Supplies ("M&S") and Prepayments. The amount claimed by CECo is $10,265,242. MS believes this element should be no greater than $2,300,000.

1. Materials and Supplies

MS argues that CECo has failed to justify the over $9.3 million of transmission related materials and supplies in working capital. CECo developed the M&S component by applying a gross plant allocation to transmission of 14.0346 percent to M&S amounts related to total electric operations. An MS witness noted that CECo's FERC Form 1 includes only $772,157 for transmission related M&S. CECo further claims that the other components of M&S,

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15 / Per Ex. S-40 at 22.
16 / Per Ex. S-56 at Column 4.
17 / Average of Short Term Growth x 2 and Long Term Growth.
18 / [(Weighted Growth x .5) +1] x Composite Dividend Yield.
19 / Adjusted Yield + Weighted Growth.

construction, production plant, distribution plant and "other," were not shown to bear a relationship to transmission. MS also contends that the evidence strongly suggests that the CECo claimed M&S amount includes sums related to construction that are well in excess of an amount that would be replaced to maintain the inventories for normal maintenance, which MS contends is the prevailing standard. Missouri Utilities Co., 6 FERC ¶ 63,041 at 65,234 (1979), aff'd, 10 FERC ¶ 61,297 (1980), reh'g denied, 11 FERC 61,203 (1980).

CECo responds to the latter MS argument by noting its duty, under an MPSC Order dated March 14, 1980 in Case U-5281, to charge materials used for significant construction projects directly to the job. Accordingly, CECo maintains, these amounts do not go through the Materials and Supplies account. As to the FERC Form 1 argument, CECo's witness Gaarde testified that he applied the customary methodology to determine M&S amounts, by applying the ratio of transmission gross plant to total gross plant, which is 14.0346 percent, to the thirteen month average balances of electric M&S. Mr. Gaarde further testified that the MS witness erred in selecting only the amount labeled "Transmission Plant" on the FERC Form 1, whereas a portion of the "Construction" amounts are properly includable in transmission related M&S. Ex. CE-55 at 5-7. Accordingly, CECo contends that MS seriously understated the amount of M&S to be included in working capital.

Staff agrees with CECo's position that the FERC Form 1 is not the best source for determining transmission related M&S.

2. Prepayments

CECo applies the gross plant allocation factor for transmission, 14.0346 percent to determine the amount of prepayments to be included in transmission related working capital. MS argues that some items in the prepayment base, such as nuclear property insurance, nuclear liability insurance and government nuclear costs, are clearly unrelated to transmission and should have been deleted from the base amount before the allocation was made. CECo responds that the allocation procedure provides a suitable substitute for the more painstaking item by item approach. The Company observes that some base items will be 100 percent inapplicable to transmission, while others will be 100 percent applicable to transmission. The use of an allocation factor should balance out the inequities. Tr. at 64-5. It would, according to CECo, be unfair to delete only the items that are not transmission related before applying the allocator, because this would skew the result in favor of the transmission customer, who would then pay only 14 percent of some items that are 100 percent allocable to transmission.

Ruling on Materials and Supplies and Prepayments:

The Company has relied upon the traditional and customary means of determining the M&S and Prepayment components of working capital. While the gross plant allocation factor may not achieve perfection in determining the precise amounts of M&S and prepayments allocable to transmission, it is a time-tested and reasonable approach. Pacific Gas & Electric Co., 16 FERC ¶ 63,004 at 65,015 (1981), aff'd., 20 FERC ¶ 61,340 (1982).

The challenges by Michigan Systems fail to demonstrate that use of the gross plant allocator here would be inappropriate either for M&S or Prepayments. CECo's witness persuasively showed that use of the FERC Form 1 would be an unacceptable substitute for the gross plant allocation method to determine transmission related M&S because it does not clearly show each element of M&S that is related to transmission. Ex. C-55 at 5-7. As for Prepayments, the choices are to conduct an item-by-item review of the components in the base Prepayment amount to ferret out those Prepayments related to transmission, or to use an appropriate allocation factor. CECo employs the latter technique, which is acceptable given the onerous nature of the alternative. The approach advocated by MS, namely to first delete all non-transmission related items and then apply the allocator, would bias the results by giving inadequate recognition to items in the Prepayment base that are wholly related to transmission. The Company's claimed amounts will be accepted for the M&S and Prepayment components of Working Capital.

ISSUE 2 C -- General Advertising Expense

Michigan Systems and Staff argue that the $31,600 of CECo's general advertising expenses included in the transmission cost of service should not be allowed because the Company has failed to show that the advertising is in any way related to transmission service. CECo defends inclusion of this amount in the transmission cost of service, arguing that the advertising costs allocated to transmission are related to community activities and are not for the purpose of attracting or retaining customers. Tr. at 1591; Ex. CE-58.

Ruling on General Advertising Expense:

The expenses at issue here are directed toward communications with constituencies and informational activities that are normal business expenses for an enterprise of this nature. See Ex. CE-58. There does not appear to be anything nefarious about the Company's advertising goals. Nor can the sum claimed be seen as an undue burden. CECo will be allowed to include in its transmission cost of service the modest portion of its corporate advertising budget claimed here.

ISSUE 2 D -- Taxes Other Than Income Taxes

Michigan Systems seek to disallow the $144,982 allocated to transmission service of the $2,835,451 total assessment paid by CECo to the MPSC. CECo explains that this fee is a levy assessed against every utility doing business in Michigan. MS argues that the fee is collected to defray the state of Michigan's regulatory costs, which are not applicable to transmission service regulated by the FERC. Customers taking service under the OATT, MS argues, should not bear any portion of the MPSC's costs, which are incurred to regulate firms and services under the State's jurisdiction.

Ruling on Taxes Other Than Income Taxes:

As CECo argues, this expense is more in the nature of a cost of doing business in Michigan than one that can be parsed between regulatory jurisdictions. Nor is the issue as crystal clear as MS suggests. At one point in its reply brief, MS states that MPSC's regulatory actions do not benefit CECo's transmission customers, yet the intervenor argues elsewhere that MPSC's jurisdictional determinations support its particular views on rate base issues. The amount claimed by CECo will be allowed as a reasonable allocation to transmission service of a cost assessed by the State against utilities that operate in Michigan.

ISSUE 2 E -- Revenue Credits

Transmission use by short term and non-firm customers provide revenues that are used to offset the fixed costs that long term firm users are expected to bear. Order No. 888 at 31,738; Order No. 888-A at 30,262. Here, CECo proposes a credit of $4,950,433, derived from wheeling and interconnection revenue ($2,699,333) and intersystem capacity revenue ($2,252,600). The latter figure was derived by allocating to transmission service 31 percent of CECo's test year wholesale coordination sales to non-requirements customers, that being the ratio of transmission to production in CECo's historical cost of service. Michigan Systems argue that this latter calculation does not properly reflect rate design under the OATT. Exs. MS-41 at 12; MS I.B. at 124-125.

MS contends that CECo's FERC Form 1 for 1995 discloses sales for resale energy of 1,352,090 MWh. Based upon this level of sales, and the Company's computed credit, the imputed transmission rate is 1.66 mills per kWh, far below the on-peak hourly rate of 4.6 mills per kWh and off-peak hourly rate of 2.2 mills per kWh that CECo seeks in this proceeding. CECo's revenue credits, MS maintains, should reflect the short term and non-firm rates that CECo will charge, not some proxy value. If CECo's proposed transmission rates are approved, the credits would be far higher than CECo has proposed.

CECo claims to have used an accepted allocation methodology for computation of the credit. Indeed, CECo contends that MS' witness Coles used an allocation comparable to CECo's in testimony he introduced in the Company's 1995 case, Docket No. ER92-331-000. Tr. at 1422-23. CECo asserts that its 31 percent allocation factor is very generous when its proposed transmission revenue requirement of $110,040,000 is compared to its 1995 total generation cost of service of $1.625 billion. Ex. CE-21 at Schedule 1 and 2. If bundled sales to non-requirements customers were to be priced on the basis of fully allocated cost of both production and transmission, the transmission component would be only about 6.3 percent thereof, CECo argues.

Staff agrees with CECo, contending that MS has failed to show that CECo's proposed allocation is unreasonable. Staff argues that the 31 percent allocation proposed by CECo is based upon a ratio of transmission investment to total production and generation investment, which it claims is a reasonable method of splitting revenues generated from opportunity type transactions between the production and transmission function. Staff R.B. at 24.

Ruling on Revenue Credits:

While it may be possible, indeed preferable, to find a more precise calculation of the revenue credits at issue here than the allocation proposed by CECo, this record does not contain an alternative calculation that has the necessary credibility to warrant departing from CECo's proposed method. The allocation methodology advocated by CECo produces acceptable results and its reasonableness is validated by MS witness Coles' use of a similar allocation in a previous case. MS simply has not demonstrated that a calculation based upon the 1995 FERC Form 1 data would produce a more accurate revenue credit than the allocation offered by CECo. CECo's proposed revenue credit will be adopted.

ISSUE 2 F -- Plant Held for Future Use

Michigan Systems challenge the $6,808,497 amount included by CECo as Plant Held for Future Use because it originally applied to a proposed interconnection project, identified as the "PSI- Line," that has been canceled. Ex. MS-46 at 3. CECo witness Erickson testified on rebuttal that, despite cancellation of the PSI-Line project, CECo plans to use the land and rights-of-way to construct a step-down substation in Branch County, Michigan, to strengthen the system in that area. Ex. CE-73 at 51. CECo further notes that the MPSC approved inclusion in Plant Held for Future Use of a portion of the land and rights-of-way originally intended for the PSI-Line project. Id. CECo contends that this constitutes a sufficient plan to qualify this plant for the category of Plant Held for Future Use. CECo maintains that the Commission long ago dropped any requirement that lands be held under a specific plan to be used within a finite time period, citing Pacific Gas & Electric Co., 16 FERC ¶ 63,004 at 65,020 (1981), aff'd 20 FERC ¶ 61,340 (1982) and Cajun Electric Power Coop. Inc. v. Gulf States Utilities Co., 47 FERC ¶ 63,024 at 65,056 (1989), modified on other grounds, 59 FERC ¶ 61,041 (1992), remanded on other grounds, sub nom., Gulf States Utilities Co. v. FERC, 1 F.3d 288 (1993).

Staff, also citing to Pacific Gas, points out that CECo has indicated that it plans to construct a new step-down substation on this land in Branch County, tentatively scheduled for year 2004. Staff contends that this is sufficient manifestation of a plan for future use to include the subject land and land rights in the rate base.

Ruling on Plant Held for Future Use:

Pertinent precedent clearly establishes that there is no requirement that a utility have a definite plan to use land and property rights within a finite period to qualify the plant for inclusion in rate base as Plant Held for Future Use. Accounting Treatment for Land Held for Future Utility Use and for Profits or Losses Realized Through sales of Those Lands, Order No. 420, 45 FPC 106 (1970); modified, Order No. 420-A, 45 FPC 340 (1971); Pacific Gas, 16 FERC ¶ 63,004; and Cajun Electric, 47 FERC ¶ 63,024. Here, as argued by CECo and Staff, there is enough of a plan for the prospective use of the land and land rights at issue to qualify for inclusion as Plant Held for Future Use. A specific use has been identified for the land, namely reinforcement of CECo's transmission system in southern Michigan, including construction of a step-down substation in Branch County, within a reasonable time frame, i.e., by the year 2004. Ex. CE-73 at 51. Thus, CECo's proposal is adopted.

ISSUE 3 A -- Rate Divisors - Ludington Pumped Storage Plant

Michigan Systems propose that 917 MW of transmission demand associated with Detroit Edison's entitlement to a share of the output of the Ludington Pumped Storage Facility ("Ludington") be included in developing the denominator by which CECo's annual revenue requirement is divided to derive a rate per kilowatt of service. The proposal is grounded in Detroit Edison's use of CECo's transmission network to deliver the output of Ludington, which is located in western Michigan. Ex. MS-41 at 14. MS contends that the dedicated use of the transmission network to deliver the output of Ludington to eastern Michigan must be accounted for in the denominator, along with network and other point-to-point demands or reservations. MS further argues that the Ludington plant places an unusually high burden on the CECo's transmission network, in that it must be capable of transmitting the obligated amount to Detroit Edison. This burden, MS maintains, should not be neglected. Staff concurs with Michigan Systems' proposal, in principle. Ex. S-28 at 30. However, Staff calculates the appropriate load and divisor addition to be 443 MW, which coincides with the 1995 test year twelve monthly coincident peak ("12-CP") average of Detroit Edison's Ludington entitlement available for delivery across CECo's transmission lines. Ex. CE-68 at 13.

CECo presents testimony of its witness Waits who contends that simplistic addition to the divisor of Detroit Edison's ownership share of Ludington fails to recognize the history and operating procedures of the tight pool arrangement between CECo and Detroit Edison known as the Michigan Electric Coordinated Systems ("MECS"). The two utilities have made reciprocal investments in transmission facilities since 1962 to facilitate an economic dispatch arrangement on a cash-free, but not cost- free basis, CECo contends. CECo further claims that simply adding the number of megawatts attributable to Detroit Edison's ownership share of Ludington to the divisor would ignore the investment in transmission paid by Detroit Edison as part of the reciprocal arrangement. To recognize this investment, it would be necessary to adjust the numerator, as well, the Company argues.

CECo also presents an alternative to full inclusion of the Detroit Edison's share of Ludington in the divisor, contending that the numbers proposed by MS and Staff are far too high because only a small amount of the power generated by Detroit Edison's share of Ludington typically moves across CECo's transmission lines to Detroit Edison. CECo calculates a twelve-month average flow to Detroit Edison to be 36 MW, which accounts for the fact that in only four months of the 1995 test year did the net of all interconnection flow, coincident with CECo's peak, exit CECo.

MS responds to CECo's arguments, contending that there is no basis upon which to conclude that the Michigan pooling arrangement justifies Detroit Edison's avoiding cost responsibility for the Ludington transmission entitlement. Neither are the downward adjustments to the 917 MW entitlement proposed by Staff and CECo justified, according to MS. CECo is committed to deliver Detroit Edison's 49 percent share of the full output of the Ludington plant, and must at all times be capable of delivering the contracted amount of service, MS maintains. This commitment is analogous to a firm, point-to- point reservation, Michigan Systems argue. Accordingly, MS sees no basis for a downward adjustment for actual use. Tr. at 992- 96.

Ruling on Rate Divisors - Ludington Pumped Storage Plant:

MS and Staff are correct that it is appropriate to include the transmission demand associated with Detroit Edison's share of the Ludington Pumped Storage Plant in the denominator used to derive a rate per kilowatt of service. This is because Detroit Edison makes use of CECo's transmission network to deliver the output of the Ludington plant to eastern Michigan. Ex. MS-41 at 14. It would be improper to ignore the burden of this demand on CECo's transmission network. CECo's argument that the potential benefits afforded by Detroit Edison's reciprocal investments in transmission should be reflected in the numerator, if the divisor is adjusted as MS proposes, is unavailing because CECo makes no concrete proposal for such an adjustment. It is clear that the Commission requires cost allocation of firm services. See Minnesota Municipal Power Agency v. Southern Minnesota Municipal Power Agency, 68 FERC ¶ 61,060 at 61,206 (1994). The commitment here is akin to firm, point-to-point service. Tr. at 999. The Commission's Order No. 888 similarly includes in the denominator for point-to-point service and network service the contract demands of all firm customers. Order No. 888 at 31,738.[20] Because this significant firm demand is not otherwise reflected in the denominator, it must be included.

Next is the argument surrounding the correct share of Detroit Edison's capacity output of Ludington to be included in the denominator. To recapitulate, MS argues for the 917 MW that represent Detroit Edison's full share of the plant's output on the theory that CECo must be prepared to meet that level of demand if called upon to do so. Staff favors 443 MW, which is a calculation of actual usage based upon 1995 test year data. CECo would include only 36 MW, which is based upon an analysis of electron flows during the test year.

MS has the better argument. The intervenor is correct that CECo's transmission network must be capable of transmitting Detroit Edison's full 49 percent ownership share of Ludington. To allocate a lesser amount would not give full recognition to the burden on CECo's network caused by this transmission commitment. Inclusion in the denominator of the lower actual usage of the system in the test year, as proposed by Staff, would not adequately reflect this firm service responsibility and would transfer to other ratepayers some of the cost burden associated with this arrangement. CECo's analysis is even less reliable and would result in practically no recognition of the burden of this large commitment. MS' proposal to include 917 MW in the denominator is thus adopted.

ISSUE 3 B -- Rate Divisors - Generation Capability of CECo's Retail Customers

Michigan Systems and Staff urge inclusion in the rate denominator of the loads of CECo's retail customers who have a portion of their load served by their own generation sources, so-called "behind the meter" generation. Staff suggests 106 MW, based upon a 12-CP method. MS supports the same divisor, but argues that it should be 133 MW, if a 1-CP method is ordered. MS and Staff contend that the Commission's Order No. 888 requires that a network customer's entire load, including load served by generation that is "behind the meter," be included in allocating transmission costs. Order No. 888 at 31,736 and Order No. 888-A at 30,257-61.

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20 / CECo does not include any coincident peak demands associated with Ludington in the 12-CP transmission demand divisor. Ex. S-28 at 30. Thus, based on this provision of Order No. 888, no removal of demand is necessary.

CECo contends that this adjustment is inappropriate since there is no evidence that any retail customer of CECo owning "behind the meter" generation is taking unbundled service from CECo. Nor, CECo argues, is there any evidence of a pooling arrangement among these retail customers, making independent generation of these CECo retail customers non-comparable to MCCP member generation.

Ruling on Rate Divisors - Generation Capability of CECo's Retail Customers:

The issue here is the proper allocation of cost responsibility to "behind the meter" loads. The Commission's Orders No. 888 and 888-A plainly require inclusion in the rate denominator of "behind the meter" loads. CECo's arguments are, as MS argues, distinctions without a difference. The 106 MW of CECo's load served by "behind the meter" generation should be included in the load ratio share calculation for determining the transmission costs allocated to network customers.

ISSUE 3 C -- Load Ratio Share Calculation Method for Network Integration Service

ISSUE 3 D -- Annual Cost Divisor for Firm Point-to-Point Service

CECo proposes to use a 12-CP divisor for both the load ratio share calculation for network integration service and for the calculation of point-to-point service rates. CECo offered testimony of its witness Rasmussen, who claimed that the 12-CP approach is appropriate for CECo in light of its relatively flat demand curve. Ex. CE-17 at 8-10. The 12-CP method is also consistent with the Commission's Order No. 888, argues CECo, by pointing to language by the Commission reaffirming use of the twelve monthly coincident peak methodology because the majority of utilities plan their systems to meet their twelve monthly peaks. Order No. 888 at 31,736.

Edison Sault and ABATE argue that CECo's rates for transmission service should be derived using a 3-CP load divisor developed from the three highest consecutive months in a rolling twelve-month load ratio share. Edison Sault's witness, Dr. Axelrod, compared CECo's monthly peaks during its on-peak season (as a percentage of CECo's annual system peak) to the average of CECo's monthly system peaks during its off-peak season (as a percentage of CECo's annual system peak) for the test year 1995. He found the differential to be 21 percent, which he contended was higher than the 19 percent employed by M.E. Small in his guide to FERC ratemaking[21] as an upper bound for the appropriateness of the 12-CP methodology. Ex. ES-1 at 9-12. Dr. Axelrod's 21 percent differential "corrects" the 19 percent derived by CECo's witness Rasmussen in Ex. CE-17 because Dr. Axelrod concluded that Mr. Rasmussen inappropriately included September in his calculation of peak months. Id. Edison Sault also contends that CECo has an increasingly pronounced summer demand, as reflected in the general decline of the annual to average peak test percentages. Exs. ES-5 at 3; ES-6 at 3. Edison Sault contends the Commission has never adopted the 12-CP methodology where the difference between peak and

21 / M.E. Small, A Guide to FERC Ratemaking of Electric Utilities and Other Power Suppliers (Edison Electric Institute, 3rd ed. 1994).

off-peak ratios is over 19 percent. Southwestern Public Service Co., 18 FERC ¶ 63,007 at 65,034 (1982). When above 19 percent, Edison Sault argues, the Commission has favored 4-CP or 3-CP approaches. Id.; Commonwealth Edison Co., 15 FERC ¶ 63,048 at 65,196 (1981), aff'd, 23 FERC ¶ 61,219 (1983) (Opinion No. 165); Louisiana Power & Light Co., 14 FERC ¶ 61,075 at 61,129 (1981) (Opinion No. 110).

ABATE argues that the 12-CP methodology is appropriate only where a utility cannot plan its system without considering each and every monthly system peak. It contends that there is no evidence that CECo plans its system by looking at each monthly peak. ABATE's witness Dauphinais submitted an analysis of planning criteria from which he concluded that CECo plans its subtransmission system almost exclusively with respect to the three summer peak months, based upon acceptance of a risk of interruption when load is in excess of 80 percent of annual peak. Ex. ABATE-1 at 15; ABATE I.B. at 12. He further asserted that with transmission system power factors higher in the non-summer months than in summer months, less reactive power is required per kW of real power load. Lower reactive power in the summer months translates into less need for reactive compensation by transmission facilities to maintain non-summer system voltages, suggesting to the witness that the 3-CP methodology better tracks cost causation than does the 12-CP approach. Further, ABATE contends that CECo plans its 138 kV and 348 kV bulk transmission system by meeting certain thermal and voltage requirements at 100 percent of annual peak load, which ABATE contends further supports a 3-CP method. The summer peak demands, ABATE states, are distinctly higher than non-summer months, suggesting that the transmission system can be planned by considering only annual peak transmission loads. Finally, ABATE points out that Detroit Edison has agreed to use of 3-CP allocation in Docket No. OA96-76-000. Because Detroit Edison and CECo operate in a tight pool, rates should be designed for the two entities by using the same methodologies, ABATE maintains.

MS agrees with CECo that the 12-CP method should be used to calculate load ratio shares for purpose of charging for network integration transmission service, but argues that firm point-to- point rates should be based upon a 1-CP denominator. MS sees the use of 12-CP for the former purpose as consistent with the Commission's Order No. 888, but urges that the rationale should not be extended further. MS points to the Commission's decision in Allegheny Power System, Inc., where the Commission stated that its conclusion in Order No. 888, that it would no longer summarily reject a firm point-to-point rate developed by using the 12-CP method, does not make use of the 12-CP divisor a change necessitated by Order No. 888. MS I.B. at 139, citing 80 FERC ¶ 61,143 at 61,529-30, n.27. With CECo's current more flexible point-to-point service offering, MS argues, a divisor that captures the increased flexibility but avoids the risk of over- allocation of transmission costs to point-to-point customers must be chosen. A 1-CP approach would meet that need, MS contends. The nature of the service needs to be taken into account, according to MS. MS further asserts that use of a 12-CP divisor for point-to-point service will result in unjustified inconsistency by treating the cost of a MW of reservation-based point-to-point service as equal to the cost of a MW of transmission for the provider's native load. MS concludes that the services are different and the differences in service characteristics make it reasonable to utilize different cost allocation methods.

Staff performed an independent analysis and concluded that the 12-CP method is appropriate. Staff contends that it complies with the Commission's Order No. 888, which it construes as directive on this point. Staff claims that ABATE and Edison Sault have failed to show that CECo plans its system to meet an annual system peak, which Order No. 888 requires for methods other than 12-CP. Staff's witness Oxendine introduces five tests to support his 12-CP recommendation, including three analyses employing averages: (1) an average for five previous years of the difference between purported peak and non-peak months (13.18 percent) Ex. S-28 at 6-7; (2) the ratio of the minimum peak to the annual peak (73.82 percent), which he concluded was high enough to suggest there is no significant peak period; and (3) the average of the twelve monthly peaks to the highest monthly peak (82.6 percent), which was higher than the 81 percent threshold for use of 12-CP, as described in Illinois Power Co., 11 FERC ¶ 61,186 at 61,387 (1980). In addition, Mr. Oxendine performed two tests comparing the number of times non-peak demands exceeded peak demands. Both of these studies support the use of 12-CP, according to Mr. Oxendine. Ex. S-28 at 9.

Ruling on Load Ratio Share Calculation Method for Network Integration Service and Annual Cost Divisor for Firm Point-to- Point service:

Order No. 888 and Commission precedent point squarely in the direction of the use of the 12-CP for the load share ratio calculation. After rejecting the notion that load ratio was an inappropriate basis upon which to allocate costs, the Commission stated:

> We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual peak...are free to file another method if they demonstrate that it reflects their transmission planning.

Order No. 888 at 31,736.

While not requiring use of a 12-CP allocation methodology, the Commission in Order No. 888-A stated that it would reject alternatives unless they were demonstrated to be consistent with the utility's transmission system planning and did not result in an over-collection of the utility's revenue requirement. Order No. 888-A at 30,256.

Edison Sault's attempt to justify use of a 3-CP method relies too heavily on one year, 1995, which was atypical. Ex. S- 28 at 8. Its further attempt to show a trend of increasingly pronounced summer peaks also relies too heavily upon the atypical 1995 data. Further, the "annual to average peak test" percentages for the years preceding 1995 are all above the Commission's 81 percent cut-off, confirming the propriety of the 12-CP allocation method. Edison Sault I.B. at 5; Exs. ES-5 at 3; ES-6 at 3. Staff's witness performed a series of tests to determine the appropriateness of the 12-CP allocation. By and large, Staff's witness employed averages of recent years experience to test his conclusion that a 12-CP allocation is appropriate. These analyses are more reliable than the alternative approaches suggested by Edison Sault.

ABATE also fails to demonstrate convincingly that the Company plans its transmission system in a manner other than by analyzing monthly peaks. Demands on the Company's system fall well within the parameters set by the Commission for use of the 12-CP allocation, as Staff argues. Moreover, CECo's non-summer peaks exceed its prior year's summer peaks on many occasions between 1992 and 1996. Ex. S-28 at 10. In sum, there is no persuasive evidence that the use of 12-CP would be inappropriate here as an allocation method for network integration service.

MS contends that even if 12-CP were selected as appropriate for calculation of load ratio shares for network service (a position with which it agrees), a 12-CP methodology should not be applied to point-to-point service. MS, however, fails to show why a 12-CP methodology would be inappropriate for point-to-point service, or, more importantly, why 1-CP would be more appropriate. It argues that the differences in point-to-point service from network service warrant different approaches to cost allocation and rate design, but does not show why such differences point to the propriety of a 1-CP allocation. This deficiency is all the more critical in light of the Commission's decision in Order No. 888, which acknowledged the similarities between network and point-to-point service and recognized that the 12-CP methodology could reasonably be used to allocate costs for both. The differences in the two services noted by MS are not material enough to warrant departing from the general guidance suggested in Order No. 888. The 12-CP allocation is deemed appropriate for point-to-point service, as well as for network service.[22]

ISSUE 3 E -- Annual Cost Divisor for Non-Firm Point-to-Point Service

CECo maintains that there should be no difference in the divisor used to calculate Firm Point-to-Point Service rates from that used to calculate Non-Firm Point-to-Point Service rates. Ex. CE-21 at Schedules 9, 10. MS, on the other hand, contends that a divisor of over 9,200 MW, which represents the total amount of generation (including non-utility generation) connected to CECo's transmission system, should be used for non-firm service. Ex. MS-41 at 17-18. MS argues that unless the denominator for non-firm service is larger than for firm service, pricing for non-firm service will be identical to that for firm service and will not reflect the interruptible nature of the service. MS contends that the Commission's policy is that non- firm transmission prices should reflect the interruptibility of the service and promote efficient use of the system. Order No. 888-A at 30,272. MS points to the Commission's actions in Northern States Power Co., 64 FERC ¶ 61,324 (1993), Order Denying Reh'g and Granting Clarification, 74 FERC ¶ 61,106 (1996), where the Commission adopted system capacity as the non-firm divisor, as MS is requesting here. Michigan Systems maintain that, since CECo does not discount non-firm service, the higher divisor is necessary to develop a rate that reflects the true character of the service, which is inferior to firm, and thus ought not to be priced identical to firm.

CECo counters this argument with the Commission's decision in AES Power, Inc., 74 FERC ¶ 61,220 at 61,746-7 (1996), where the Commission accepted the transmission provider's use of annual system peak as a proxy for transmission system capability in the design of non-firm

22 / MS' arguments that customers should be able to vary contract demand and that billing determinants should be measured at the lower of the sum of capacity reservations at their receipt or delivery points are rejected as insufficiently supported and inconsistent with the provisions of Order No. 888.

rates. CECo contends that its transmission system is not capable of carrying at the same time the power generated by all of CECo's generation resources, including non- utility generators, operating at 100 percent of capability. Using system capacity as a divisor would, according to CECo, completely ignore the need for unused generation reserves in utility planning. CECo further maintains that the Commission has consistently articulated a policy of allowing non-firm rates stated as a ceiling rate to be capped at the firm rate, citing in support Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, FERC Stats. & Regs. (Regulation Preambles 1991-1996) ¶ 31,005 at 31,137 (1994); Order No. 888 at 31,743-44; Order No. 888-A at 30,272. CECo sees the MS position as an attempted end run around the Commission's asserted refusal to compel across-the-board discounts for non-firm point-to-point service. Staff agrees with CECo's position, emphasizing that Michigan Systems' argument runs counter to the Commission's decision in AES Power, Inc.

Ruling on Annual Cost Divisor for Non-Firm Point-to-Point Service:

Were one free to explore the merits of this issue in the absence of the Commission's fairly recent pronouncement on virtually the same issue in AES Power, Inc., one might conclude that MS has the better argument. That the rate for non-firm service has historically been capped at the firm rate is not necessarily license to charge the same rate for both services. Indeed, earlier Commission precedent cited by MS, including Northern States, seems to recognize the intuitive logic of pricing an inferior service at rates lower than the superior service. But the precedent established in AES Power, Inc. is clearly controlling here. The Commission recognized there that the utility's firm customers pay all of the costs of the transmission system, without regard to the amount of energy actually scheduled for delivery, whereas the non-firm customers pay only when the company transmits energy for them. The Commission stated, at 74 FERC at 61,747:

> This is appropriate, given that the transmission system is planned to meet firm load, based upon probable conditions, plus contingency conditions for reliability purposes. The system is not planned to deliver the maximum output of all generating units simultaneously.

MS here argues that non-firm service should be priced based upon the assumption rejected by the Commission above. Moreover, MS fails to distinguish, or even mention, AES Power, Inc. Accordingly, CECo's proposal to use system peak as the rate divisor for hourly non-firm point-to-point service is adopted.

ISSUE 3 F -- Short-Term Divisors

CECo's witness Rasmussen explained how the Company developed on-peak daily rates by dividing weekly rates by five, and off- peak daily rates by dividing weekly rates by seven. Similarly, he stated that hourly on-peak rates should be calculated by dividing the daily rate by sixteen, and that off-peak hourly rates should be calculated by dividing by twenty four. Ex. CE-17 at 9. CECo explains that this proposal represents a modification of the so-called Appalachian pricing method historically accepted by the Commission.[23] CECo argues that this modified Appalachian proposal provides a reasonable compromise among the interests of the transmission provider, the short-term customer, and the long-term customer who pays the cost of the transmission system.

MS argues that the Commission should adopt an 8,760 divisor for hourly service, contending that CECo has failed to justify use of the Appalachian pricing methodology for short term rates. It contends that CECo seeks to price short term service based upon a fiction that weeks have only five days and days have only sixteen hours, which reduces the rate divisor and increases the unit rate. MS contends that Appalachian pricing will overcharge short term users and is unnecessary, given the governing pro forma tariff terms and conditions. These terms, according to MS, obviate any concern that short term uses will compromise recovery of the Company's system fixed costs by preempting longer term reservations. Michigan Systems argue that the tariff terms make clear that short term service is provided out of left-over capacity, and only if none of the long term users for whom capacity was built want to use it. Reducing the divisor as CECo proposes will simply increase the subsidy paid by short-term customers in that period, MS contends.

CECo again responds citing recent Commission precedent. It calls attention to the Commission's decision in IES Utilities, Inc., et al., 81 FERC ¶ 61,187 at 61,833-34, where a modified Appalachian pricing proposal, identical to the one proposed here by CECo, was adopted over the recommendations of the Presiding Administrative Law Judge, who favored 8,760 hours as a divisor. The Commission was persuaded by the actual usage of the applicant's service, namely, that significantly more usage occurs during peak periods than during off-peak periods. The Commission also rejected the argument that time-differentiated non-firm pricing may result in over-collection. CECo contends that the facts here are similar to IES Utilities and supports a finding that its short term divisor proposal is just and reasonable.

Staff agrees with CECo, noting that the Company here proposes not traditional Appalachian pricing, but a modified version where two rates are developed: an on-peak rate applicable for 4,160 hours, and an off-peak rate applicable only for the off-peak hours. Staff reasons that, if a short term customer is using capacity during on-peak hours, it is getting the same use of capacity as a long term customer using the system during that on-peak period and ought to pay the same price. Staff maintains that the Commission agreed that use of peak pricing conformed to the pro forma tariff, and Staff supports CECo's proposal here.

Ruling on Short-Term Divisors:

The Commission's recent decision in IES Utilities, Inc. and its more recent decision in Entergy Services, Inc., 85 FERC ¶ 61,163 (October 30, 1998), adopting a modified Appalachian

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23 / Under Appalachian pricing, a uniform rate applicable in all 8,760 hours of the year is developed by dividing annual costs by only 4,160 hours. Appalachian Power Co., et al., 39 FERC ¶ 61,296 at 61,965 (1987). See also American Electric Service Power Corp., 80 FERC ¶ 63,006 at 65,067-69 (1997).

pricing proposal, points us in the direction of CECo's similar offering here. The facts of this case seem squarely in line with those of IES Utilities, Inc., and the arguments offered by MS do not provide a convincing rationale for a departure from that Commission precedent. Staff's argument that short term usage during the peak period should be priced on the same basis as long term on-peak usage is reasonable. Moreover, CECo's proposal achieves substantial rate justice in that it recovers appropriately from those who take service at the time of the peak 4,160 hours, while basing off-peak rates on a distribution of annual costs over all of a year's 8,760 hours. Thus, CECo's proposal for calculating appropriate divisors for daily and hourly point-to-point transmission service rates is adopted.

ISSUE 4 -- Real Power Loss Factors

CECo's proposed open-access tariff provides loss factors for Point-to-Point and Network Integration transmission service. Those loss factors are 3.86 percent for deliveries metered at the low voltage side of the applicable transformer (below 33 kV) and 3.22 percent for deliveries metered at the high voltage side of the applicable transformer (33 kV and above).[24] These loss percentages, based upon a study using 1995 data, are calculated by taking the average losses from load flow solutions modeling system conditions at twelve monthly peak demand hours. Ex. CE-4 at 5.

Staff and ABATE contend that power loss factors should be calculated based upon average system losses over 8,760 hours per year, instead of the twelve monthly peaks, as proposed by CECo. Staff contends that the twelve average peak losses are greater than the losses in most of the non-peak hours during the year. Therefore, Staff asserts, when the proposed factors are applied during all 8,760 hours of the year, they will compute more losses than are actually experienced by the Company. Ex. S-8 at 21-22. Staff had proposed a set of loss factors in its initial testimony (Ex. S-8 at 21), and then revised those factors (Exs. S-28 and S- 30 at 26). However, late in the proceeding, Staff received a copy of the Company's 1995 actual loss factors from its 8,760 hourly power flows. Ex. S-59. Staff now argues that it is better to compute power loss factors by using the actual data from the 8,760 hourly power flows than by using the factors estimated in its testimony. Staff I.B. at 58. Staff's final recommendations are to use the following factors:

High Side (120 kV and above)	1.71 percent
Low Side (120 kV and above)	2.25 percent
High Side (46 kV)	3.08 percent
Low Side (46 kV)	3.50 percent

Id.

ABATE agrees with Staff that the 1995 actual data on the 8,760 hourly flows should be

24 / If a voltage differentiated rate structure is adopted, the real power loss factors, using CECo's 12-CP methodology, would be 1.81 percent for power metered at or above 120 kV, 2.56 percent for power delivered from 120 kV and above lines but metered at distribution voltage, 3.58 percent for power metered at 46 or 23 kV, and 4.20 percent for power delivered from 46 or 23 kV lines, but metered at distribution voltage.

used to calculate the power loss factors.[25] ABATE argues that CECo's power loss factors will lead to overrecovery of the Company's revenue requirement because in the vast majority of hours, loss factors predicated on only the twelve monthly peak hours will overstate actual losses. Tr. at 90; see also Ex. CE-88. Use of the hourly power flow analysis of the 8,760 hours will eliminate this problem, according to ABATE. ABATE's recommendations differ from Staff's, however, as a result of what CECo claims are computational errors on Staff's part, in light of the fact that the real power loss factors are not applied to meter readings at the point of receipt, as Staff assumed. ABATE's recommendations, with which CECo agrees if the factors are to be based upon 8,760 hourly flows in 1995, are as follows:

High Side (138 or 345 kV deliveries)	1.71 percent
Low Side (138 or 345 kV deliveries)	2.30 percent
High Side (46 or 23 kV deliveries)	3.17 percent
Low Side (46 or 23 kV deliveries)	3.73 percent

Ex. ABATE-1 at 27.

Consumers Energy responds that, under Staff and ABATE''s methodology, it will underrecover its actual real power loss costs. CECo claims that calculation of average loss factors based upon losses occurring at the twelve monthly peaks, as it proposes, will prevent shifting loss costs onto CECo's native load customers from other transmission users. Ex. CE-73 at 44. The Company offers Exhibit CE-87, which purports to show that a 1.71 percent loss factor for 345 kV and 138 kV deliveries, derived from CECo's 8,760 hourly flows, would underrecover its actual real power loss costs. ABATE notes, however, that Exhibit CE-88 shows an overrecovery using the 1.81 percent factor derived from CECo's proposed twelve monthly peak power flows for most of the deliveries at 345 kV and 138 kV, and an underrecovery only for deliveries over about 6,600 MW, which occur infrequently. Tr. at 90.

Ruling on Real Power Loss Factors:

For the reasons suggested by Staff and ABATE, it has been shown that loss factors derived from the 1995 actual 8,760 hourly power flows will be more reasonable than the alternative proposal advanced by CECo. Staff and ABATE have demonstrated that power loss factors that are based upon the twelve monthly peak methodology will cause over recovery of power loss costs in most of the hours of the year. Id. CECo's fear of underrecovery if the 8,760 hourly power flow methodology is used is overstated in light of the low number of hours per year that delivery levels triggering higher losses will occur. Id. at 87-90; see also Ex. CE-88. Further, ABATE's proposed factors will be accepted in light of CECo's agreement that they are more accurate than Staff's, if the 8,760 methodology is employed. Staff points out that it should be made clear, if CECo and ABATE's figures are used, that real power loss factors are to be applied to customer billing meter readings at the point of delivery. CECo should so indicate in its tariff.

ISSUE 5 A -- Scheduling, System Control and Dispatch Service

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25 / ABATE's recommendations are close to Staff's, but differ slightly. Compare Ex. ABATE-1 at 27 with Ex. S-59.

- Unit Rate Calculation

CECo defines the Scheduling, System Control and Dispatch Service as a service "required to schedule the movement of power through, out of, within, or into a Control Area." Ex. CE-22 at Sheet No. 109. To support its rate calculation for this service, CECo presents testimony of its witness Rasmussen. Ex. CE-17 at 10-13. According to Mr. Rasmussen, the cost of this ancillary service should include 84 percent of the cost of investment, operation and maintenance associated with the Michigan Electric Power Coordination Center ("MEPCC"). Id. at 11; Ex. CE-4 at 2. This allocation is based on MEPCC's labor costs that are associated with transmission operations. See Ex. CE-5.

Furthermore, according to CECo, this service must include 72 percent of the costs for accounting and billing services in the Transmission Transactions Department. Ex. CE-17 at 11; Ex. CE-4 at 3. Mr. Rasmussen claims that any transaction over 3,000 kW should incur a monthly demand charge of $0.056/kW. Ex. CE-17 at 13; see also Ex. CE-22 at Sheet No. 109. To arrive at this figure, CECo uses an annual revenue requirement of $3,873,000 and a 12-CP denominator. Ex. CE-17 at 12-13.

Michigan Systems do not propose a specific rate, but claim that the appropriate cost denominator for this service should be based upon a 1-CP denominator, and that the divisor for short term transmission should be 8,760 hours. MS I.B. at 154. MS' witness Coles argued that the unit rate should be based on total MECS applicable charges and total system load and that the appropriate center costs should be divided by the total loads. Ex. MS-41 at 19. Furthermore, Mr. Coles testified that the Appalachian method of pricing should not be used because "[s]cheduling is a seven day week process and should not be priced on a five day week." Id. at 20.

Staff agrees that the short term transmission rates for this service should be based on 8,760 hours, but disagrees that the appropriate divisor should be based on 1-CP. Staff R.B. at 41-42. Staff calculated that, based on a $3,873,000 annual revenue requirement, the appropriate monthly rate should be $0.051/kW. Staff explains that its proposed unit rate is lower than CECo's figure because a higher divisor is required for consistency with its positions in Issue Nos. 3 A and 3 B. Staff I.B. at p. 59, citing IES Utilities, Inc., 81 FERC ¶ 61,187 (1997), reh'g denied, 82 FERC ¶ 61,089 (1998).

Ruling on Scheduling, System Control and Dispatch Service - Unit Rate Calculation:

The unit rate calculation should be derived from the revenue requirement identified by the Company and Staff, divided by the 12 CP-based demand, including the higher divisor required because of decisions rendered above in Issue Nos. 3 A and 3 B.[26] Consistent with decisions rendered above in Issue Nos. 3 D and 3 F, the position advanced by MS, namely that the denominator should be 1-CP, is rejected for the reasons advanced in the rulings on those issues. Finally, short term rates should be based on 8,760 hours. IES Utilities, Inc., 81 FERC ¶ 61,187.

26 / The calculation should reflect the 106 MW and 917 MW additions made in Issue Nos. 3 A and 3 B.

ISSUE 5 B [27] -- Scheduling, System Control and Dispatch Service

- Minimum Charge

CECo proposes a bifurcated rate for scheduling, system control and dispatch service. For transactions of 3,000 kW or less, CECo proposes a minimum transaction charge of $2,031/year (or $169/month or $39/week, depending upon the duration of the individual transaction). Ex. CE-17 at 13; see also Ex. CE-22 at Sheet No. 109. For transactions over 3,000 kW, the proposed demand charge discussed in Issue 5 A would be added to the proposed minimum charge. See Ex. CE-22 at Sheet No. 109. CECo's witness Rasmussen proposes that each customer have a minimum scheduled transaction of 1,000 kW, with a 2,000 kW deviation band, which would allow for a use of 3,000 kW of transmission service. Ex. CE-17 at 12-13.

According to CECo, this minimum charge should be included because it reflects the fixed cost component of providing this service. Id. To support its position, CECo reasons that the resources used to supply this service are affected more by the number of transactions than the size of the transaction. Ex. CE- 17 at 12. As an example, Mr. Rasmussen stated that a transmission controller may be able to support 20 transactions of 100 MW, but not 22 transactions of 10 MW. Ex. CE-17 at 12. Citing IES Utilities, Inc., 80 FERC ¶ 63,001, CECo acknowledges that ratemaking must recognize a myriad of factors, which often may be in conflict. Thus, CECo argues that these fixed costs must be recognized as part of this service. CECo R.B. at 97.

ABATE's position is that, if a minimum charge is adopted, it should be no higher than 1,000 kW, which is the minimum that can be scheduled under CECo's proposed tariff. ABATE I.B. at 18. ABATE challenges CECo's proposed rate for two reasons. First, ABATE witness Dauphinais testified that charging for the service at a minimum quantity of 3,000 kW is highly discriminatory to those customers with loads between 1,000 kW and 3,000 kW. Ex. ABATE-1 at 34. Second, Mr. Dauphinais challenged CECo's proposed rate because the Company charges weekly rates even for those customers taking service for terms of less than one week. Id.

MS and Staff oppose the use of any minimum charge. MS argues that CECo has incorrectly calculated its scheduling system control and dispatch charges by proposing excessive and discriminatory transaction charges. MS I.B. at 154-157. MS claims that CECO's charge is unsupported because its calculation is wrong. According to MS, CECo developed its minimum charge by using a divisor based on the twelve monthly average peak and asserts that the "appropriate center costs [s]hould be divided by the total loads." Id. at 155. MS further claims that CECo also unreasonably used a five-day week instead of seven-day week in scheduling. Id. at 156. MS continues, arguing that CECo failed to show that it incurs the same costs in scheduling and monitoring a short-term transaction as when it provides service to a longer transaction when using the same transmission system, MS contends. Id.

MS believes that CECo's proposal that all customers pay a minimum charge regardless of use, directly conflicts with the ratemaking principle "that all customers ...bear the cost responsibility associated with their respective uses." Id. at 157, citing Order No. 888 at 31,703.

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27 / This issue was mistakenly labeled as Issue 5 C in the joint statement of issues.

MS claims that CECo's proposed rate discriminates against customers with loads under 3,000 kW. Id. MS witness Coles testified that "for customers of less than 3,000 kW, the transaction charge would mean that the customers would pay more per Kilowatt than larger customers." Ex. MS-41 at p. 20. The charge is large enough, according to MS, that it can make a difference in whether a customer can or cannot engage in a transaction. See Ex. ABATE-1 at 34. In turn, this would prevent CECo's transmission customers, many of whom use CECo's system to deliver their generation, from competing with CECo for power sales. MS I.B. at 157. MS argues that CECo should develop hourly rates for this service. Id.

Staff also characterizes CECo's proposed minimum charge as unjust and unreasonable because the proposed rate does not include any safeguards against over-recovery of expenses. Staff R.B. at p. 42. Instead, Staff agrees with MS that the Company should adopt short term rates reflecting the actual amount of service needed for a specific duration. Id. Staff argues that the scheduling rates must be designed in the same manner as the rates for base transmission service. Id. at 42-3, citing Allegheny Power Inc., et al, 80 FERC ¶ 61,143 at 61,541-42 (1997). Because base transmission rates do not have minimum transactional charges, Staff argues neither should the rates for scheduling service. Id. at 43. Staff argues that CECo's proposed demand charge should be adjusted for duration and applied to all transactions, according to Staff. Staff I.B. at 60.

Ruling on Scheduling, System Control and Dispatch Service - Minimum Charge:

CECo has failed to justify the proposed minimum charge. MS argues persuasively that a transactional charge of this nature can have anti-competitive implications. By charging an up-front fee for each small transaction, smaller customers can be prevented from using openly accessible resources to compete as envisioned in Order No. 888. Staff is right, also, in its position that no showing has been made by CECo to demonstrate that the proposed transaction charge, in concert with the usage charge, will not overrecover the costs of providing the service. The costs of providing this service should be recovered in usage charges.

ISSUE 6 A -- Reactive Supply and Voltage Control From Generation Sources Service - Allocation Percentages

ISSUE 6 B -- Reactive Service - Revenue Requirement

ISSUE 6 C -- Reactive Service - Unit Rate Calculation

CECo determines that 27.7 percent of its generator capability supports reactive power production and that 33.3 percent of its exciter capability is used to control reactive power output of the generator. This results in a weighted average investment of 29.7 percent of generator and exciter resources that are used to produce reactive power. Ex. CE-17 at 13-14. This calculation, plus 0.232 percent of real power production related to reactive power, totals the net production plant resource investments associated with reactive power. Id. Dividing this figure by total production plant investment, CECo derives a 1.46 percent factor for reactive power. Id.

There are two issues raised regarding these calculations. First, CECo's 33.3 percent allocation factor of exciters is based upon a review of the equipment specifications and documentation provided by six of CECo's generators, which CECo contends is a representative sample including plants of varying size and fuel type. CECo I.B. at 74. Staff argues that the exciter allocation factor should be based upon the reactive capability of all generating units, since data for all units is readily available. Accordingly, it proposes a 27.7 percent factor, derived from its analysis of all of the data. Exs. S-8 at 9; S-12 at 5.

Second, Staff also allocates to reactive service the cost of Generation Step-Up Transformers, consistent with its position on Issue 1 E, while CECo did not. CECo I.B. at 73.

The revenue requirement will, of course, be derived on the basis of previous determinations of return and other issues and does not present a separate issue for resolution here.

Turning to the unit rate calculation, MS believes that it should be based upon a 1-CP denominator and that an 8,760 hour divisor should be used for short-term transmission. MS I.B. at 159. Staff maintains that a 12-CP denominator is preferable, but agrees with MS that an 8,760 divisor should be used for short term transmission.

Finally, MS argues that a separate reactive service support charge is unreasonable here absent completion of a refunctionalization of costs, previously deemed to be transmission costs, for facilities which actually perform production functions. MS I.B. at 158. MS contends that CECo has made no effort to achieve more than a partial refunctionalization by assigning production costs to transmission. It needs also to complete the refunctionalization by identifying CECo's transmission costs that should appropriately be assigned to production, MS asserts. MS cites Northern States Power Co., 64 FERC ¶ 61,324 (1993), Order Denying Reh'g and Granting Clarification, 74 FERC ¶ 61,106 (1998), where the Commission advised Northern States that if in the future it sought to refunctionalize certain generation costs to the transmission function, it must consider and be prepared to accept legitimate offsetting refunctionalizations of certain transmission costs to production. Id. at 63,380.

CECo characterizes as a radical notion MS' argument that no charge at all for reactive service be permitted unless a comprehensive study is made of what elements of transmission investment should be refunctionalized to the production function. CECo calls attention to what it describes as a similar challenge that was rejected by the Commission. CECo cites to AES Power, Inc., 74 FERC ¶ 61,220 at 61,744 (1996), and to the initial decision in American Electric Power Service Corp., 80 FERC ¶ 63,006 at 65,074 (1997), which, CECo contends, firmly rejected a similar argument by transmission customers. CECo further maintains that MS' argument calling for a complete refunctionalization study before allowing a reactive service charge is a collateral attack on Order No. 888's determination that all transmission providers' tariffs set forth a separate unbundled charge for reactive service.

Ruling on Reactive Service Allocation Percentage, Revenue Requirement and Unit

Rate Calculation:

Staff is correct that an allocation percentage based upon a complete analysis of exciter information for all generating units is preferable to the smaller sample employed by CECo. Also, to be consistent with the determination above in Issue 1 E on GSUs, the costs of GSUs should be included in the reactive service charge, as proposed by Staff. The revenue requirement and unit rate calculations should similarly follow previous determinations on issues affecting these calculations. The unit rate calculation should, as Staff recommends, be based upon a 12-CP divisor in order to be consistent with earlier determinations. An 8,760 hour divisor for short term transmission is also the most convincing alternative available on this record.

As to MS' claim that no charge should be allowed for reactive service pending a complete refunctionalization study, the short answer is that Order No. 888 requires an unbundled charge for this service and the proposal on the record is sufficiently supported to be deemed just and reasonable. Like other issues in this case, however, this is one where CECo seems to have one foot in the old transmission world and one in the new. At some early point in the future, it will be necessary for CECo, in order to more properly structure rates under the open access regime envisioned by Order No. 888, to conduct the type of refunctionalization analysis advocated by MS. This should be done at the earliest opportunity.

ISSUE 6 D -- Reactive Service - Recognition of Customer-Supplied Reactive Support

This issue concerns the extent to which the MCCP should receive a credit against the cost of service for reactive power supplied to CECo from generating units owned by MCCP's members. CECo proposes that only the MCCP members' 6.69 percent ownership share of the Campbell 3 generating unit should entitle MCCP members to any reactive power credit. This is because CECo does not have the operational ability or contractual authority to dispatch other MCCP-owned units to produce reactive support on demand. CECo contends that, under the guidance provided by Order Nos. 888-A and 888-B [28], MCCP's local generation does not provide the type of reactive support necessary to qualify as a partial credit against charges for reactive service. CECo I.B. at 76. Staff agrees that only if CECo has the ability to control MCCP's generating units should MCCP be entitled to the credit. Accordingly, Staff would allow the credit only for the unit that is jointly owned by CECo and MCCP, namely the Campbell 3 facility.

On brief, MS does not argue that other MCCP units than Campbell 3 are entitled to a credit against charges for reactive service, but instead maintains that Michigan Systems' units can satisfy the Commission's requirements, citing arrangements that CECo has made with other non-utility generators. MS I.B. at 161. CECo opposes what it suggests is an attempt by MS to negotiate in its brief some type of reactive service compensation arrangement for MCCP members. CECo maintains that its currently filed Network Service Agreement for MCCP (Ex. CE-79) already provides an adequate vehicle for facilitating reactive power supply compensation.

Ruling on Reactive Service - Recognition of Customer- Supplied Reactive Support:

28 / Order No. 888-A at 30,228; Order No. 888-B at 62,094.

The record will support a credit against charges for reactive power for MCCP's 6.69 percent ownership share of the Campbell 3 unit only. MS no longer argues for additional credits, recognizing that other MCCP member-owned generating units are not under CECo's control to produce reactive power on demand. The argument presented on brief by MS that transmission customers should be able to obtain credits for the reactive supply their generators provide under arrangements similar to those made with certain non-utility generators is beyond the scope of this proceeding.

ISSUE 7 -- Regulation and Frequency Response Service

ISSUE 7 A -- Annual Revenue Requirement
ISSUE 7 B -- Unit Rate Calculation
ISSUE 7 C -- Purchase Obligation

These issues overlap and are resolved below.

The Commission defines Regulation and Frequency Response service as:

> [a service] necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz) [...] accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow moment-by-moment changes in load.[29]

CECo asserts that for its operations, the appropriate annual revenue requirement for regulation and frequency response is $712,605,000 times an allocation factor of 1.65 percent, or $11,758,000. In calculating the $712,605,000, CECo claims that the generation investment should include units dispatchable through telecommunications systems but not equipped with Automatic Generating Control ("AGC"), as well as those that are so equipped. CECo I.B. at 77; see also Ex. CE-89 at 3. CECo argues that these units should be included because they are capable of providing Regulation and Frequency Control. Id.

In calculating the allocation percentage of 1.65 percent, CECo proposes to take the 6 percent operating reserve requirement for the year 1995, equal to 432 MW, and divide it by the annual

29 / Order No. 888 at 31,960.

dispatchable generation of 6,550.4 MW. CECo I.B. at 78. Thus, CECo comes up with 6.6 percent of dispatchable generation, which it argues should be allocated towards the rates for the ancillary services of Regulation and Frequency Response, Spinning Reserve and Supplemental Reserve. Ex. CE-17 at 15. Next, CECo proposes that the total allocator of 6.6 percent be divided in the following manner: 25 percent to Regulation and Frequency Control, 25 percent to Spinning Reserve and 50 percent to Supplemental Reserve Service. Id. This leads to respective cost allocators of 1.65 percent, 1.65 percent and 3.3 percent. Id.

Staff proposes a slightly lower annual revenue requirement of $698,390,924 with a 1.31 percent allocation factor, or $9,148,922. Staff's revenue requirement figure is lower than CECo's because its calculation follows certain adjustments it has proposed as part of its case in this proceeding, including rate of return, selection of plant providing service and deletion of GSUs. Staff R.B. at 46. MS supports Staff's proposal. MS I.B. at 162.

According to Staff witness Smith, only those units equipped with AGC should be considered as providing capacity for the Regulation and Frequency Response Service. Ex. S-8 at 10. Staff asserts that the only generator units likely to provide this service are the following: Campbell 1 & 2, Cobb 4-5, Whiting, Kern 1 & 2, Kern 3 & 4, Weadock 7 & 8 and the Ludington Pumped Storage unit. Id. Except for CECo's nuclear, peaking and run-of-river hydro units, all CECo units have AGC controls. Id.

Staff's allocation percentage for this service is lower than CECo's. Staff claims that the allocation percentage for Regulation and Frequency Response should be 1.31 percent. Staff I.B. at 64. Staff bases its allocation on hourly load deviations.

CECo proposes a monthly rate of $0.17/kW based on its proposed allocation factor of 1.65 percent. On the other hand, Staff proposes that the appropriate monthly rate for CECo's Regulation and Frequency Response should be $0.11/kW based on an allocation factor of 1.31 percent. Staff I.B. at 65. Staff's proposed unit rate is 29 percent lower than CECo's because Staff disagrees with CECo's generating investment amount, its allocation percentage and its kW divisor. See Ex. S-35 at Schedule 3.

MS does not propose a rate for this service, but claims that the annual cost denominator for ancillary services should be based on 1-CP, the same as in the case of point-to-point transmission service. MS I.B. at 162.

CECo proposes a customer purchase obligation of 1.5 percent. CECo I.B. at 78. CECo computes this figure by allocating the 6 percent operating reserves in the following manner: 25 percent for Regulation and Frequency Response (1.5 percent), 25 percent for Spinning Reserve (1.5 percent), and 50 percent for Supplemental Reserve (3.0 percent). Id. CECo believes that it is impossible to develop "a scientifically accurate way of making an allocation" between Regulation and Frequency Response and Spinning Reserves and that an equal split would facilitate administration for both CECo and its customers. Id.

Staff argues that the appropriate purchase obligation for the Regulation and Frequency Response Service should be 1.31 percent. Staff I.B. at 65. Although Staff agrees with CECo's total 6 percent operating reserves, it disagrees with CECo's proposed manner of allocating it. Staff witness Smith explained that according to East Central Area Reliability ("ECAR"), at least 3 percent of the operating reserves must be spinning reserves and located within the utility's control area. Ex. S-8 at 14, citing Ex. S-13 at 4. Staff asserts that the spinning reserve portion is used to provide load regulation and system frequency control. Ex. S-8 at 4. The remaining 3 percent of capacity may be off-line but must be capable of serving the load within ten minutes. Id. Staff argues that this 3 percent should not be split equally, as CECo proposed. Staff R.B. at 47. Instead, Staff developed a 1.31 percent customer purchase obligation for Regulation and Frequency Response, and a 1.69 percent purchase obligation for Spinning Reserve Service. Id. at 47. Mr. Smith explained that it is reasonable to calculate the level of reserves needed by CECo for regulation service through the following method: 1) calculate the hour-to-hour deviations using CECo's hourly load data in FERC Form No. 714; 2) calculate the average of these deviations and divide this average by 2; 3) divide the number obtained in step 2 by CECo's 12-CP load; and 4) express the number obtained in step 3 as a percentage. Ex. S-8 at 10-11; see also Ex. S-16. Mr. Smith explained that in the second step, it is necessary to divide by 2 in order to account for hourly deviations that may be either above or below the scheduled amount. Ex. S-8 at 11-12; see also Ex. S-18.

Mr. Smith's proposed method is based on the following assumptions: "(1) load growth (or drops) on a linear basis during the hour; (2) the instantaneous variations in load are relatively small compared to the hourly load change; (3) a customer serves its load by block-scheduling its average hourly energy needs from an entity either inside or outside the control area; and (4) [CECo] does the same to meet its hourly load." Ex. S-8 at 11. According to Mr. Smith, the load regulation requirement can be used to describe additional capacity required hourly to match to generation load. Id. CECo argues that Staff failed to show that these significant assumptions apply to CECo's operations.

Furthermore, Staff believes CECo's open access tariff is silent as to the customer purchase obligation for this service and that it should provide the following language:

A Transmission Customer purchasing Regulation and Frequency Response service will be required to purchase an amount of reserved capacity equal to 1.31 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service or 1.31 percent of the Transmission Customer's Network Load for Network Integration Transmission Service. The billing determinants for this purchase will be reduced by any portion of the 1.31 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

Id. at 13. CECo argues that this assertion is incorrect because "Ex. CE-22 states in Sheet No. 112 that the customer must secure this service 'in an amount of 1.5% of Customer's Reserved Capacity or Network Load, as the case may be.'" CECo R.B. at 100.

Ruling on Regulation and Frequency Response Service Issues:

Order No. 888 specifically defines Regulation and Frequency Response as being "accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment)." [30] Staff is correct in including only those units equipped with AGC in its proposed generation investment for this service. The fact that these units are dispatchable through telecommunications systems does not infer that they provide Regulation and Frequency Response service.

The North American Reliability Council ("NERC") Operating Policy for Generation Control and Performance specifically states that, "[e]ach CONTROL AREA shall maintain generating regulating capability, synchronized to the INTERCONNECTION, that can be

30 / Order No. 888 at 31,960.

increased or decreased by AGC to provide for adequate system regulation and Control Performance." Ex. CE-6 at 4. Thus, NERC specifically requires that the generators responsible for this service be responsive to AGC. CECo fails to show that the units it proposes to add to the revenue requirement determination for this service meet these standards.

Further, Staff's allocation percentage is supported by the evidence and recent Commission decisions. Accordingly, it is preferable to the allocation proposed by CECo, which was determined to preserve administrative convenience.

The Commission has addressed the method of calculating the Regulation and Frequency Response (also called load following service) and showed that it is not impossible to develop a scientifically accurate way of making an allocation. Allegheny Power Service Corp., 85 FERC ¶ 61,275. Where no actual data demonstrating the moment-to-moment fluctuations in load on the system was available, such as in this case, the Commission adopted an average of all hourly load changes during the year. Id. at 62,120.

In the initial decision in Allegheny Power, the Presiding Judge noted that the average of all hourly load changes during the year, rather than the average of monthly system peaks, is appropriate because "[regulation and frequency response] is intended to respond to fluctuations in load that occur constantly." Allegheny Power Service Corp., 77 FERC ¶ 63,024 at 65,173 (1997). He further explains this is so because "cost incurrence for load following does not occur at the peak...and does not address additional capacity or generation at time of peak only." Id. Moreover, the Presiding Judge decided that the load variation must be divided by 2, as the amount of generation a customer scheduling its load is providing exceeds energy for a portion of the hour. Thus, the regulating margin must be provided only when the customer's load is in excess of the average for the hour. Id. at p. 21; see also Kentucky Utilities Co., 85 FERC ¶ 61,274 at 62,107-09. Staff's proposal in this case follows the basic method used in Allegheny Power and Kentucky Utilities.

In addition, ECAR has recently adopted a separate 1 percent minimum for regulation and frequency response. See Allegheny Power, 85 FERC at 62,121; Kentucky Utilities, 85 FERC at 62,109. Staff's proposed figure of 1.31 percent for regulation and frequency response service is reasonable in light of this requirement. CECo's rationale is unsupported by the evidence and is purely arbitrary.

Based on this methodology, the regulation and frequency response percentage for CECo's system requires that the 75 MW regulation margin be derived by dividing the load change of 150 MW by 2, an that it be spread over the 5,747 MW average twelve monthly peaks. This leads to an allocation factor of 1.31 percent. Thus, I adopt Staff's proposal regarding the annual revenue requirement (to be adjusted consistent with relevant findings herein), unit rate calculation and purchase obligation for Regulation and Frequency Response Service.

Finally, the tariff language proposed by Staff witness Smith is adopted since it explicitly allows for an adjustment of 1.31 percent to the billing determinants if the transmission customer chooses to obtain Regulation and Frequency Response Service elsewhere.

ISSUE 8 A -- Energy Imbalance Service - Capacity Charge

In Order No. 888, the Commission determined that a transmission provider must offer Energy Imbalance Service within and into its control area. Energy Imbalance is defined as "the deviation between the scheduled and actual delivery of energy to a load in the local control area over a single hour." Order No. 888 at 31,717. The Commission further in that Order provides for a deviation band of plus or minus 1.5 percent of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the transmission customer's transactions, with the expectation that imbalances would be eliminated within a reasonable period (usually 30 days). Imbalances within the deviation band that remain uncorrected and imbalances outside the deviation band would result in charges to the transmission customer. Id. at 31,960-61.

CECo asserts that for imbalances outside the 1.5 percent deviation band, there should be a capacity charge of $50/kW during certain critical periods when CECo's spinning reserves drop below 3 percent. CECo I.B. at 79. CECo further proposes a demand charge of $2.42/kW per day for energy imbalances outside the deviation band during CECo's on-peak non-critical periods.[31] Id. CECo claims that it should be allowed to include capacity charges for Energy Imbalance Service provided outside the deviation band to compensate it for providing generation

31 / Hereinafter these proposed charges are referred to as "capacity charges."

capacity for this service and to preclude customers from paying penalties for excessive amounts of Energy Imbalance Service instead of securing adequate generating capacity to meet their firm load. Id. CECo contends that the issue is "how high this non-cost based rate should be to deter the undesirable practice of taking energy outside the Commission-prescribed deviation band." CECo R.B. at 101.

At the time the parties filed their briefs, the Commission had not provided guidance on Energy Imbalance Service pricing. Thus, CECo examined the regulation of natural gas companies for parallel pricing principles. Specifically, CECo argues that Commission policy in the gas industry recognized the need for penalty rates to ensure operational integrity of a utility during critical periods. CECo R.B. at 101, citing Northern Natural Gas Co., 77 FERC ¶ 61,282 (1996), mod. on reh'g., 78 FERC ¶ 61,355 (1997).

CECo witness Waits testified that the energy imbalance charges are aimed to keep the system in a reliable state. Ex. CE-4 at 4. Mr. Waits asserted that CECo will face financial penalties if it does not meet control performance requirements which are made worse by energy imbalances caused by other utilities. Id. at 4-5. On rebuttal, he claimed that Energy Imbalance Service is the most appropriate means of creating incentives to keep actual interconnection power flow equal to the flow scheduled. Ex. CE-68 at 5-6. CECo witness Rasmussen rationalized that, since Energy Imbalance Service is infrequently used, energy-only billing is insufficient to recover the capacity cost of providing this service. Ex. CE-17 at 19-20. CECo asserts that only 1 percent of the hours during the one year period from December 1996 to November 1997 would be considered on-peak critical periods. CECo R.B. at 101.

Staff, Michigan Systems, ABATE and the City of Holland argue that there should be no capacity charges. Michigan Systems challenge CECo's justification for such charges contending that CECo failed to show that it actually installed or reserved generation capacity for this service. MS R.B. at 51. Michigan Systems also assert that CECo fails to show that the proposed energy imbalance charge would deter customers from electing to take the energy imbalance service rather than securing other resources. Id.

Michigan Systems, Staff, ABATE and City of Holland claim that CECo's proposed rates are excessive. MS I.B. at 167-70; Staff I.B. at 67-71; ABATE I.B. at 21; Holland I.B. at 8-16.

Staff asserts that CECo's capacity charges are "inappropriate, unsupported, and vastly overpriced." Staff I.B. at 67. Staff explains that CECo's proposed rates include, in addition to the capacity charges, an energy charge of $100/MWh, or 110 percent of the cost of replacement energy, whichever is greater, during on-peak hours, and $50/MWh or 100 percent of replacement costs, whichever is greater, during off-peak hours. Id.; Ex. S-1 at 13. Staff believes that CECo's charges for all services outside the deviation band should be limited to the greater of 110 percent replacement cost or $100/MWh energy charge, and that no capacity charges should apply. Staff I.B. at 71; Ex. S-1 at 14.

City of Holland and Michigan Systems argue that the $100/MWh energy charge will serve as sufficient incentive for customers to avoid imbalances because the resulting penalty is higher than the cost of replacement energy. Holland I.B. at 13; MS I.B. at 164-5. MS suggests that the charge is not so high that it would punish customers for inadvertent transmission. MS I.B. at 165. Staff agrees that the capacity charges are unnecessary, contending that they will fail to accomplish their intended purpose of signaling customers to stay in balance. Staff I.B. at 68-9.

Staff witness Oxendine testified that the demand charge proposed by CECo cannot be justified because the proposed energy charge for those services outside the deviation band will cover all the energy costs, as well as contribute towards the fixed costs. Ex. S-1 at 15-16. [32] Michigan Systems' witness Reising also testified that the proposed energy charge is more than five times the incremental cost for the MECS during 1996 and, since the energy charge is substantially greater than two times the cost penalty policy that the Commission has adopted for other provisions, the energy charges alone ought to provide incentives for good scheduling. MS I.B. at 166-67. Staff, Michigan Systems and the City of Holland argue that the energy charge alone will

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32 / Staff witness Oxendine explained that, for example, in 1995, CECo's cost of providing the last kWh of energy was less than $40/MWh for almost 99 percent of all hours, and it was less than $20/MWh for the majority of the hours. Ex. S-1 at 14-15. Thus, he stated, by paying an energy cost of $100/MWh, the transmission customer is already paying at least $60/MWh towards CECo's fixed costs. Id. at 15. Mr. Oxendine further explained that, even in the rare situations where the energy costs will rise above $100/MWh, the customer will pay a rate of 110 percent of replacement costs, and thus contribute at least $10/MWh towards CECo's fixed costs. Id.

fully compensate CECo and act to deter its customers for mischeduling. Staff I.B. at 70.

ABATE, too, opposes the proposed capacity charge, arguing that it is arbitrary and punitive, rather than cost-based. ABATE I.B. at 21. To adopt CECo's proposed charges, ABATE contends, would help perpetuate CECo's market power by dissuading customers from seeking alternative suppliers. Ex. ABATE-1 at 32. ABATE further recommends that a transmission customer be charged at the greater of $100/MWh or 110 percent of CECO's avoided cost in meeting a customer's shortfall for on-peak periods and at the rate of $50/MWh or 110 percent of CECO's avoided cost of meeting the customer's shortfall for off-peak periods. This, ABATE contends, will strike a balance between cost-based rates and the provision of adequate incentives to discourage use outside of the deviation band. ABATE I.B. at 21. ABATE deems it "absolutely critical that anti-competitive rates and charges for this service not be adopted" because they will affect both wholesale and retail rates, the latter being more sensitive to penalty rates and charges. Id. [33]

Staff asserts that CECo's proposed penalty Energy Imbalance Service charge is not cost justified because it is 16 times higher than the cost of a combustion turbine that is likely to be used for this service. Staff I.B. at 68, citing Tr. at 901-02. Staff also argues that the penalty is out of proportion to the violation because the demand charge is the same for the entire month, even where the imbalance may have occurred only for one hour of the critical on-peak period. Id. Lastly, Staff argues that CECo did not justify its proposed "critical periods" and that it failed to provide guidelines for distinguishing between critical and non-critical periods. Staff I.B. at 70. Staff asserts that in order to provide incentives for proper scheduling, the customer must first be notified that it is within the critical period and thus likely to incur the penalty. Id. at 71. Staff disagrees with CECo's argument that by rescheduling power the customer would avoid the penalties, because Staff finds that the customer would not even be aware of its deviation, and that the price signal may fail to reach the customer in time. Id.

City of Holland characterizes the penalty as "a random event that is poorly connected to desired behavior." Holland I.B. at

33 / ABATE argues in its Reply Brief that penalty charges should not be applied to imbalances inside the deviation band. ABATE R.B. at 14-15. Since this was not an issue identified as contested, no discussion is included on this matter herein.

12. Moreover, it claims that CECo's own failure to meet its spinning reserves may lead to application of the penalties to transmission customers. Id. In reply, CECo argues that this is not an issue because it is willing to allow transmission schedule changes on 20-minute notice and that ECAR members are expected to recover from loss of a generating unit within 10 minutes. CECo R.B. at 103-104.

CECo rebuts Staff and intervenors' position, contending that the charges for imbalances outside the deviation band are designed to be a penalty for mis-scheduling by transmission users, and thus, they do not have to be cost-based as long as they are reasonable. CECo R.B. at 101. City of Holland replies by stating that, "[w]hile penalties are not required to be cost-based, the utility should set its penalties at a level sufficient to promote good utility practice by its customers, but not to become overly punitive." Holland I.B. at 13. Michigan Systems also argue that although the price for energy imbalance is supposed to serve as a disincentive for improper behavior, the disincentive rate must be reasonably set "because a rate set too high could be exploitative and exorbitant." MS I.B. at 164, citing Florida Power & Light Co., 66 FERC ¶ 61,227 at 61,530 (1994).

Michigan Systems further claim that even if the capacity charge would provide some incentive for good scheduling when the charge is first incurred, it will no longer continue to motivate behavior in the next hour. MS I.B. at 167. Moreover, Michigan Systems argue that the capacity charges actually will lead to bad scheduling practice through uneconomic dispatch and the intentional generation of more energy by the MCCP because the consequences of incurring the charges are so high. Id. at 169-170.

CECo claims that Staff's proposed rate of $100/MWh is insufficient. CECo's witness Rasmussen claims that Staff's proposed $100/MWh would not even cover CECo's variable costs for its combustion and generation units. Ex. CE-17 at 19-20. According to Mr. Rasmussen, the variable costs for these units exceed $180/MWh and fuel costs alone for these generators average $83/MWh. Id.; see Ex. CE-24. Moreover, Mr. Rasmussen asserted that excessive use of Energy Imbalance Service outside the deviation band may reduce CECo's ability to serve native load customers. Ex. CE-17 at 18. However, Mr. Rasmussen admitted on cross examination that the $100/MWh is greater than the actual replacement cost in almost all hours. Tr. at 868. He also recognizes, that where no other costs are involved, the 110 percent replacement cost would be available to cover some capacity costs. Id. at 872.

City of Holland claims that CECo's penalty argument relying on similar pricing mechanisms in the regulation of natural gas companies is misplaced for several reasons. First, City of Holland argues that, unlike the natural gas industry, capacity charges for energy imbalances are not unauthorized use penalties, but rather are rates for a contracted-for ancillary service, and thus, must be cost-based. Holland R.B. at 3. Second, the City of Holland distinguishes the flow between electric systems from flows on natural gas pipelines. It argues that natural gas companies have several mechanisms available to provide reasonable resolution of imbalances without penalty, which do not exist for energy imbalances. Id. at 4-5.

Staff also places emphasis on the operational differences in the natural gas industry and argues that "because storage, pressure needs and configurations are different on gas and electric systems, it is not reasonable to extend concepts about imbalance and scheduling penalties from the gas pipeline to the electric utility industry." Staff R.B. at 49. Furthermore, Staff argues that CECo failed to show that excessive imbalance service during the time when the highest penalty charge would apply -- 1 percent of total hours -- threatened system integrity. Id. at 50. Thus, Staff concludes that CECo failed to demonstrate conditions similar to those in Northern Natural.

City of Holland further argues that CECo's proposed penalty rate is unreasonable in light of the Commission's policy because the Energy Imbalance Service capacity charges proposed by CECo are significantly higher than twice the corresponding rate for transmission service. Holland I.B. at 8-9. It argues that, under Allegheny Power, the proposed penalties would be accepted only if "they are capped at a level equal to twice the standard rate for the service at issue." Id. at 9, citing Allegheny Power Systems, Inc., et. al., 80 FERC ¶ 61,143 at 61,545-6 & n.131. Michigan Systems also address this issue by arguing that charging twice the utility's highest rate provides sufficient incentive to guard against relying on other systems. MS I.B. at 166, citing Indiana Michigan Power Co., 44 FERC ¶ 61,313 at 62,078-9 (1988).

Additionally, City of Holland argues that CECo's proposal is inconsistent with Order No. 888 because, although a transmission customer is required to acquire Energy Imbalance service, "it may do so from the transmission provider, a third party or self-supply." Holland I.B. at 13, citing Order No. 888 at 31,715-16. By arbitrarily penalizing the transmission customer, CECo removes the customer's opportunity to choose its services and penalizes even in those situations where the customer cannot control inadvertent exchanges of power. Holland I.B. at 14. Michigan Systems claim that no control area operator can totally prevent inadvertent energy exchange. MS R.B. at 53-4.

City of Holland also argues that Commission policy requires that emergency situations caused by loss of facilities should be addressed in the transmissions customer's service agreement rather than in the Energy Imbalance Service. Holland I.B. at 14, citing Order No. 888-A at 30,233; Order No. 888-B at 62,092. Lastly, the City of Holland argues that if such penalties are approved, CECo should be ordered to credit such penalty revenues to its cost of service in order to lower transmission rates for the customers to avoid inappropriate profits. Holland I.B. at 15.

CECo further supports its position by claiming that it expects to be subject to NERC-imposed penalties for non-performance. CECo I.B. at 82. City of Holland claims that this argument is meritless because no such penalties currently exist nor does NERC expect to resolve potential penalties until January 2000. Holland R.B. at 6-7. City of Holland states that a utility cannot collect rates to recover potential unknown and unmeasurable costs. Id. at 7, citing 18 C.F.R. § 35.13(d)(1)(ii). Staff argues that CECo is not likely to experience such penalties from NERC anyhow, because it is not possible to determine from which system the inadvertent energy imbalance originated. Staff R.B. at 51, citing Tr. at 1213.

Ruling on Energy Imbalance Service - Capacity Charge:

I conclude that CECo has not demonstrated the propriety of its proposed capacity and demand charges for imbalances outside the deviation band. First, the need for penalty charges of the nature proposed by CECo has not been firmly established. The analogy to the gas industry, particularly the Northern Natural precedent, is not on all fours, as Staff persuasively argues. The complex scheme of scheduling and imbalance penalties used in the case of gas pipelines are designed for different purposes. Scheduling penalties are set to maintain efficient pipeline operation and capacity utilization. Imbalance penalties are provided to discourage customers from tying up or depleting storage through over or under-takes of gas. Tennessee Gas Pipeline Co., 50 FERC ¶ 61,154 at 61,458 (1990). The concepts applicable in the gas industry, which involve storage, capacity, and pressure needs, are not necessarily transferable to the electric sector. While the basic idea of trying to stimulate proper planning and scheduling behavior among customers using the service is common in the circumstances of both industries, the need for and the mechanisms for providing proper incentives will not necessarily be the same. Here, CECo has not made the threshold showing that penalties as severe as proposed are required because of severe conditions, operational behavior, or threats to system integrity, all important considerations in the establishment of gas industry penalty regimes.

Moreover, it is clear that CECo's proposal has not been well thought through, in that it is uncertain to achieve the desired effect of influencing proper scheduling behavior. As City of Holland argues, the penalty is not timed in a way that is likely to change behavior. Holland I.B. at 12. In addition, the level of the proposed capacity charges is high enough to raise a concern about possible unintended anti-competitive consequences. The proposed capacity charges are well in excess of the cost of equipment likely to be used to supply this service (See Ex. S-1 at 13), well in excess of the cost of incremental generation on MECS (See Ex. MS-16 at 66-67), and are substantially above the two times cost penalty policy that the Commission has adopted for other provisions. See Allegheny Power, 80 FERC at 61,545-6 & n.131.

While the capacity charges proposed by CECo have not been shown to be justified, the record supports the need for some charges for imbalances outside the deviation band to discourage reliance upon the availability of this service for purposes other than that for which it is intended. Parties opposed to CECo's capacity charges have argued that all or elements of CECo's energy charge proposal for imbalances outside the deviation band will suffice to satisfy the need for some pricing mechanism that will influence good planning and scheduling behavior. To recapitulate, CECo proposes to apply an energy charge consisting of the greater of $100/MWh, or 110 percent of the cost of replacement energy, during on-peak hours, and $50/MWh, or 100 percent of replacement energy costs during off-peak hours. Staff's position is that all positive energy imbalances over the 1.5 percent deviation band be subject to a charge that is the greater of $100 per MWh, or 110 percent of the Consumers' system incremental cost. Ex. S-1 at 14. Other parties would apply the CECo formulation of energy charges which differentiates between on-peak and off-peak periods, applying to the off-peak periods, a rate that is the greater of $50 per MWh or 110 percent of the cost of replacement energy.

As Staff's witness Oxendine testified, the proposed energy charges for service outside the deviation band are designed to cover all energy costs and make a contribution to fixed costs. See Ex. S-1 at 15-16. They should, accordingly, provide sufficient recompense to CECo for use of its service beyond the bounds of the deviation band. Moreover, because the proposed energy charges are well above the incremental cost of generation from sources available to CECo's transmission customers (See Ex. MS-16 at 66-67), they should provide a sufficient incentive for good scheduling. Here, CECo's argument, id. at 67, that the potential energy charge of $100/MWh is a minor charge incapable of influencing customers to control energy imbalances, is supported by testimony describing a projected revenue requirement deficiency. This testimony misses the counter-argument offered by MS, among others, that the energy charge is high enough to provoke proper scheduling behavior without wreaking unintended consequences, such as the intentional generation of more energy by MCCP than might have resulted from implementation of the much higher capacity charges that have been proposed by CECo. Moreover, the imposition of onerous charges unrelated to the cost of providing the service and higher than necessary to influence proper scheduling behavior might discourage otherwise economically desirable transactions.

Finally, in circumstances like these, the Initial Decision in The Detroit Edison Co., 84 FERC ¶ 63,006 (August 13, 1998), reached the conclusion that a similar capacity charge proposal of Detroit Edison was lacking support, while a Staff proposal to rely on energy charges alone for imbalances outside the deviation band was adopted. Id. at 65,038-40.

For the above reasons, I find that CECo's proposed capacity charges have not been shown to be just and reasonable. CECo's proposed energy charges alone should apply to imbalances outside the deviation band. [34]

ISSUE 8 B -- Energy Imbalance Service - Payment of Accumulated Energy Imbalance Owed to Customer

CECo proposes to credit customers 75 percent of CECo's average decremental cost when the energy imbalance is within the

34 / I find no persuasive reason to adopt Staff's apparent position that there should be no differentiation between peak and off-peak charges. See Ex. S-1 at 14; Staff I.B. at 71. The proposal is unexplained and unsupported.

deviation band (2 MW minimum) and not returned in kind by CECo by the end of the transaction period or billing month. See Ex. CE-17 at 16; Ex. CE-22 at Sheet Nos. 116-117. CECo witness Rasmussen defines decremental cost as “"the actual replacement energy price minus any redispatching or other costs due to generation supply adjustments caused by the transmission customer’s excess energy supply.”" Ex. CE-17 at 16. CECo also proposes that there should be no payments to the transmission customers for energy imbalances for energy supplied outside the deviation band. Ex. CE-22 at Sheet Nos. 116-117. CECo argues that its proposal takes into consideration necessary incentives for proper scheduling practices. CECo I.B. at 83.

Staff, ABATE, and City of Holland propose that CECo pay to the customer 90 percent of CECo's decremental cost where the imbalance is both within and outside the deviation band. Staff and the City of Holland argue that by setting a 10 percent penalty for over-supply of energy, CECo would provide sufficient incentive for proper scheduling and would be consistent with the 10 percent penalty for under-supply of energy. Staff I.B. at 72; Holland I.B. at 17; see Ex. S-1 at 14. Staff explains that virtually every other utility credits its customers 90 percent of the decremental cost and that CECo has no cost or operational reasons why it should be treated differently. Staff I.B. at 73. Staff states that CECo does not have to pay for under or over-supply, and thus, not giving proper credit to customers when the energy imbalance is outside of the deviation band is unfair and unreasonable. Id. at 72.

Michigan Systems propose that CECo should pay customers the lesser of 90 percent of CECo's decremental cost or the transmission customer's replacement cost regardless of whether the imbalance is within or outside the deviation band. MS I.B. at 172. Michigan Systems label CECo’s proposal not to compensate for energy deliveries outside the deviation band as mere "confiscation". Id. Keeping over-deliveries without making any payment to the customer would unjustly enrich CECo and should not be permitted, according to MS. MS I.B. at 172-173. Michigan Systems explain that CECo has been receiving “"free energy”" from its customers and has refused to return the inadvertent energy upon the customer’s request. Id. at 173; see Ex. MS-1 at 27; Ex. MS-4.

Michigan Systems also argue that CECo’s proposal is discriminatory because when CECo over-delivers to other control areas, it is entitled to return of the energy in-kind. MS I.B. at 173. According to Michigan Systems, this would place CECo’s customers at a competitive disadvantage. Id.

Michigan Systems argue that reimbursement at a rate of 90 percent of CECo's incremental cost makes sense because penalties for over-deliveries and under-deliveries should be symmetrical. Id. Michigan Systems claim that the customer should be reimbursed for negative energy imbalance at 90 percent of cost because the positive energy imbalance is based on a 110 percent of incremental cost. Id. at 174. This rate would encourage proper scheduling, as the customers would have no incentive to lean towards over-scheduling or under-scheduling. Id. at 173-174.

Ruling on Energy Imbalance Service - Payment of Accumulated Energy Imbalance Owed to Customer:

In light of the evidence presented, I find that the proposed payment of 90 percent of CECo's decremental cost, advocated by Staff, ABATE and City of Holland, has been justified for over-supply of energy within and outside the deviation band. CECo failed to present persuasive evidence that paying only 75 percent of CECo's decremental cost would be just and reasonable for over-supplied energy within the deviation band and that no payment should be made for over-deliveries outside the band. As Staff and allied parties argue, a 10 percent penalty applied to decremental cost for over-supply is symmetrical to the 10 percent penalty for under-supply adopted above. Moreover, the evidence indicates that other utilities compensate for over-supplies at 90 percent of decremental cost. Tr. at 1343. CECo's proposal, on the other hand, lacks evidentiary support, is inconsistent with the practices of other utilities and lacks intuitive merit.

ISSUE 8 C -- Energy Imbalance Service - Period for Return In-Kind

CECo proposes a tariff provision that would permit in-kind payments for energy imbalances within the deviation band to be made within the period of the transmission service transaction or the applicable monthly billing period covering the period of the transmission service. CECo I.B. at 84. Staff argues that the transmission customers should have at least 30 days after receiving notice of an imbalance for returning energy in-kind. Staff I.B. at 73.

Michigan Systems contend that CECo should allow a customer to return energy in-kind within the month following the billing month, but in all cases at least 20 days from receiving notice of an imbalance. MS I.B. at 174. It asserts that the additional 20 days would present CECo's customers with a reasonable opportunity to return energy in kind. Id. at 174-5. Michigan Systems claim that CECo's provisions are "unnecessarily restrictive," especially in the case where the imbalance occurs during the last few days of the month. Id. at 174. The problem arises because CECo usually prepares the bill after the end of the billing month, and, according to MS, the customer does not have adequate information regarding imbalances until it receives the monthly billing from CECo. Id. This in turn may be too late to return energy in-kind, MS claims. Id.

City of Holland introduces a slightly different proposal that in-kind energy replacement should be made "within 30 days of the later of (a) the end of the billing period, or (b) the date [CECo] notifies the customer that an imbalance has occurred." Holland I.B. at 18. City of Holland argues that its proposal is consistent with Order No. 888, which requires a 30-day in-kind reimbursement period for energy imbalances. Id., citing Order No. 888 at 31,961; see also MS R.B. at 55, citing Order No. 888 at 30,229.

Moreover, City of Holland claims that "[t]he elimination of the pro forma tariff's in-kind return option is not appropriate." Id. at 18-19, quoting Allegheny Power Systems, Inc., et. al., 80 FERC ¶ 61,143 at 61,544 (1997). Michigan Systems point out that CECo fails to claim that reducing the period for in-kind returns is justified by the Commission's alternative standard of a "reasonable period generally accepted in the region." MS R.B. at 55. Additionally, Michigan Systems argue that CECo's proposal violates the Commission's comparability standard, as CECo itself is not subject to such returns in-kind within a specified period. Id.

CECo contends that Staff, Michigan Systems and City of Holland's assumption that the customer cannot detect the existence of an imbalance until it receives the monthly bill is unfounded. CECo I.B. at 84. On redirect, CECo witness Waits explained that the customers do not need to wait for the monthly bills, but that they can obtain such information from CECo on an ongoing basis virtually minutes after the end of each hour. Id. at 86.

CECo witness Waits explained that the accumulating meter data provided to MCCP is read on an hourly basis in the same way that the accumulating meters with other control areas are read. Tr. at 1356. Mr. Waits continued by saying that the data from these accumulating meters, subject to telemetry corrections, is used to calculate MCCP's energy imbalance. Id. at 1356-57. In his opinion, "these telemetered values will be reasonably close to the month-end values that are used for official determination." Id. at 1138. Mr. Waits acknowledged that the telemetered values can only be retrieved from CECo's meters, but that certain added technology would permit the transmission customers to read these meters on an hourly basis. Id. at 1138-1141. Mr. Waits recognized that this necessary equipment is not currently in place, but believed that it could be installed in the future. Id. at 1141.

Although not rejecting the feasibility of CECo's alternative mechanism, Michigan Systems rebut this assertion by pointing out that the record fails to support CECo's commitment to it. MS I.B. at 175. It also argues that even if this data could be obtained from CECo's meters, the transmission customer may have to invest substantially in the necessary equipment and software to use such data. MS R.B. at 56. Staff also argues that there is no indication that this data from accumulating meters is provided to all transmission customers. Staff R.B. at 53. Moreover, Staff points out that this data is subject to later correction. Id.

In reply, CECo states that it can now confirm the energy imbalance data to which Mr. Waits testified is actually available to any customer who installs the necessary facilities to receive that information and that CECo will continue to make this information available if their proposal is adopted. CECo R.B. at 105. However, the record does not specify in any detail what the necessary facilities are or who will absorb the cost of these facilities.

Ruling on Energy Imbalance Service - Period for Return In-Kind:

CECo's proposal to require that in-kind payments for energy imbalances within the deviation band be made within the period of the transmission transaction or applicable monthly billing period covering the period of the transaction is troubling because customers are not able to know that an accumulated imbalance exists until they receive the monthly bill from CECo. CECo's response, that additional technology improvements (presumably made at the customers' expense) can make this information available to customers at an earlier time (See Tr. at 1138-41), and that MS entities could receive some information from which they can determine imbalances at an earlier time (See Tr. at 1354) is not sufficient to overcome the inequity of its proposal, particularly as applied to customers who do not receive anything close to real-time information as to imbalances. I cannot find it just and reasonable to require that imbalances be returned in-kind within the period of or the billing period for the transmission transaction when the exact status of imbalances is not known by those customers until later in time. It is far more reasonable, at least until real-time information is available to all of CECo's transmission customers, to follow the MS proposal that customers at least be given 20 days from the date that CECo notifies the customer of the imbalance to schedule the return in-kind. See Ex. MS-16 at 66.

ISSUE 8 D -- Energy Imbalance Service - On-Peak Energy Charge for Energy Not Returned In-Kind

CECo and Staff propose a charge for on-peak energy imbalances within the deviation band which are not returned in-kind at a rate of the greater of (1) 110 percent of actual replacement cost or (2) $0.10 per kWh (the same as $100/MWh). CECo I.B. at 86; Staff I.B. at 74; see Ex. CE-22 at Sheet Nos. 115. Staff argues that the $100/MWh energy charge acts as a mischeduling penalty and thus does not have to be cost based as long as it is reasonable. Staff I.B. at 74. Staff explains that since the energy imbalance would be within the band deviation, the transmission customer may avoid the charge by repaying the energy in-kind. Id.

ABATE and the City of Holland disagree with this proposal and argue that the charge for energy imbalances within the deviation band should be limited to 110 percent of the actual replacement cost. ABATE I.B. at 23; Holland I.B. at 16. ABATE believes that although the proposed $100/MWh rate may be reasonable for deviations outside the band, customers should not be penalized in the same manner through an artificial floor for imbalances within the band, as they are abiding by good utility practices. ABATE I.B. at 23. ABATE argues that there should be a clear distinction between imbalances within and outside the deviation band. Id. City of Holland explains that the point of having a deviation band in the first place is to provide some leeway within which the transmission customer will not be penalized for minor deviations between its scheduled and actual load. Holland I.B. at 16.

ABATE witness Dauphinais asserted that CECo's proposal is anti-competitive and could allow CECo to retain market power over its current customers. Ex. ABATE-1 at 31. Mr. Dauphinais stated that the rate should be based on the actual cost, rather than on an arbitrary charge of $50/MWh or $100/MWh. Id. In his view, charging 10 percent above avoided costs for energy owed to CECo and crediting customers 90 percent of actual avoided costs is fair and reasonable. Id. at 32. City of Holland contends that no reasonable transmission customer would conduct its transactions at 10 percent above cost. Holland I.B. at 16.

In reply, CECo argues that ABATE fails to offer any persuasive reason why this "commonly accepted charge" of $100/MWh is not appropriate. CECo I.B. at 87. In support, CECo refers to Staff witness Oxendine's testimony that "CECo charges the higher of $100/MWh (the same as $0.10/kWh) or out-of-pocket cost plus 10% for emergency service in its interconnection agreement with neighboring utilities." Id., citing Ex. S-1 at 17. Staff asserts that Mr. Dauphinais' recommendation does not necessarily act as a disincentive. Staff I.B. at 74. Staff explains that the transmission customer may find it beneficial to lean on CECo's system in the situation where its cost of generation is higher than CECo's actual replacement cost. Id. Staff further argues that ABATE fails to show how CECo may retain market power over its customers if its proposal is implemented. Staff R.B. at 53-54. Lastly, Staff asserts that if the 110 percent charge causes customers to repay in-kind, as ABATE and City of Holland contend, then the transmission customers will never be in the position of having to pay the $100/MWh charge. Id. at 54.

Ruling on Energy Imbalance Service - On-Peak Energy Charge for Energy Not Returned In-Kind:

This proposed charge of the greater of 110 percent of incremental cost or $100/MWh is for on-peak energy imbalances within the deviation band. To recall, on-peak energy imbalances outside the deviation band would carry a charge equal to the greater of 110 percent of incremental costs or $100/MWh, which is identical to the CECo/Staff proposal here for on-peak energy imbalances inside the deviation band. However, it appears desirable to structure this charge differently from the charge for on-peak energy imbalances outside the deviation band, in order that the totality of the rate design makes sense. If the charges are the same, there would appear to be no reason for a distinction between imbalances inside and outside the deviation band or a need for a deviation band. CECo, of course, accomplishes a desired holistic consistency by proposing capacity charges for imbalances outside the deviation band. That proposal having been rejected, we must now look at alternatives offered by ABATE and City of Holland to the proposed charges for on-peak imbalances within the band to determine if a desired consistency of structure can reasonably be obtained from the information in this record.

As argued by City of Holland, the point of a deviation band is to provide some leeway for minor deviations between scheduled and delivered loads that are unintended and should be relatively penalty-free. Holland I.B. at 16. ABATE persuasively maintains that, if customers are operating within the deviation band, they are adhering to good utility practice and should not be penalized through an artificial floor for imbalance pricing. ABATE I.B. at 23. While Staff and CECo are correct in their arguments that ABATE, which also claims CECo's proposal is anti-competitive, has failed to demonstrate that particular point, neither have CECo or Staff shown why a penalty greater than 110 percent of the incremental energy cost should be levied where the customers are adhering to good utility practice in operating within a pre-determined acceptable range. It is not enough to say that the proposed rate structure is followed by other utilities. Here, the argument has been raised that CECo's "greater of" rate proposal would be unreasonable, in light of the rate proposed (and adopted above) for energy imbalances outside the deviation band. Moreover, the whole rate design for energy imbalance service cries out for a distinction between "penalties" for operating within and outside the deviation band. That can be achieved by limiting the penalty for unreturned on-peak energy imbalances to 110 percent of incremental costs, i.e., by removing the feature of CECo's proposal that would charge customers the greater of 110 percent of incremental costs or $100/MWh.

I conclude that the most reasonable and just proposal for this service, in the context of other issues decided above, is to adopt the City of Holland/ABATE proposal that would charge customers who do not return on-peak energy imbalances within the allowed time frame 110 percent of system incremental cost.

Issue 8 E -- Application of Energy Imbalance to Customers Following Load

Michigan Systems and the City of Holland argue that they are control areas and thus any unscheduled energy deliveries should be treated as inadvertent energy exchanges and returned in-kind, and not subject to Energy Imbalance Service or Unauthorized Use charges. MS I.B. at 175; Holland I.B. at 19. On the other hand, CECo asserts that a transmission customer that follows load in CECo's control area should be subject to Energy Imbalance Service and Unauthorized Use charges. CECo I.B. at 87-89.

Michigan Systems, City of Holland and Staff agree that various factors that cause the inadvertent interchanges are outside the transmission customer's control. MS I.B. at 179; Holland at 19; Staff I.B. at 75. Inadvertent flows inevitably occur due to the inherent physics of the physical grid. Holland I.B. at 19; see Tr. at 1337. Michigan Systems' witness Cooper defined the inadvertent energy exchanges as "the methods by which interconnected utilities correct for any unscheduled and unintended transfer of energy from one utility to another." Ex. MS-1 at 11. Mr. Cooper recognized the principal causes of inadvertent interchanges as: forced outages or derates of generating units, metering and telemetry errors, generation response lag, and error dispatch. Id. He testified that often it is impossible to determine which utility caused the inadvertent energy exchange. Id.

Michigan Systems claim that the inadvertent energy method has been successfully used for several years under CECo's previous transmission tariff and Coordinated Operating Agreement ("COA") with MCCP, and should continue to be treated in this manner. MS I.B. at 176. Because CECo was the one that unilaterally proposed the inadvertent energy exchanges in 1992, Michigan Systems urge that CECo should not be allowed to reasonably argue against them at the present time. Id.

CECo unilaterally terminated the COA in 1996, and replaced it with an entirely new Network Operating Agreement ("NOA"), which introduced the Energy Imbalance and Unauthorized Use charges. Ex. MS-1 at 2. Michigan Systems argue that the MCCP has responsibly performed from 1992-1996 by controlling inadvertent interchanges through the COAs and that the imposition of the new higher charges do not create incentives to control inadvertent interchanges, but rather act as an excessive penalty. MS I.B. at 183.

Michigan Systems explained that the MCCP operates as a control area. MS I.B. at 176-177. Michigan Systems' witness Cooper described a control area as an entity that: (1) meters its load and all interconnections, (2) has sufficient capacity to meet its own load plus a prudent level of planning reserves, (3) provides telemetry, communications equipment/arrangements that allow information to be exchanged with the entity's dispatch center on a near-real-time basis, (4) has an adequate amount of generation under AGC to be able to regulate its loads, (5) uses a form of Energy Management System to balance the output of the entity's power supply resources to the entity's loads plus applicable transmission losses, and (6) maintains sufficient spinning and operating reserves to absorb the effects of unanticipated load swings and reasonable levels of forced generation or transmission outages without endangering reliability. Ex. MS-1 at 9.

CECO and Staff claim that neither Michigan Systems nor City of Holland qualify as control areas. CECo I.B. at 87-88; Staff I.B. at 75. CECo witness Waits argued that the MCCP is not a control area recognized by NERC. Ex. CE-68 at 1-6. Mr. Waits contended that Mr. Cooper's definition of a control area lacks certain requirements such as generation that has governors allowed to respond properly to interconnection frequency changes or tie-line bias control. Id. at 2. Moreover, Mr. Waits argued that even if the MCCP would become certified by NERC at a future time, it should not be excused from energy imbalance service because they are in a position to control the flows of power between them and CECo. Id. at 4. City of Holland's witness Howard stated on cross examination that the City of Holland has the ability to control energy imbalances and that it is not a NERC-recognized control area. Tr. at 1336-38.

Similarly, Mr. Cooper acknowledged that the MCCP is not a NERC-recognized control area, but argued that this fact is irrelevant because the MCCP meets the criteria of a control area. Id. at 9-10. Mr. Cooper focused on the fact that CECo itself is not a NERC-recognized control area, but merely part of the MECS, which is recognized as a control area by NERC. Id. at 10. He further noted that the former COA operating provisions were at least as restrictive as the NERC operating guidelines and that the present NOA operating requirements are in fact more restrictive than NERC's requirements. Id.

City of Holland similarly argues that it currently follows and historically has followed, load in its service area although it has been part of CECo's larger control area. Holland I.B. at 19. City of Holland asserts it should be recognized as a de-facto control area and that the mismatches between actual and scheduled load should be treated as inadvertent energy and returned in-kind. Id. at 20. It explained that from 1981 to August 1997, City of Holland and CECo have also operated under a COA, which classified these mismatches as inadvertent energy. Id. City of Holland contends that this treatment should be continued as no operating problems or threats to system integrity have been identified. Id. CECo witness Waits confirmed that he is not aware of any physical modifications to the interconnection between City of Holland and CECo which necessitated this change. Id. at 21.

In reply, CECo states that the former inadvertent energy provisions in the COAs are no longer appropriate under Order 888 for those parties who use the tariff to serve load within CECo's control area. CECo I.B. at 88-9. Mr. Waits testified that by changing the inadvertent energy provisions in the COAs, CECo acted consistently with Order No. 888 because "Energy Imbalance Service and Regulation and Frequency Response Service are together designed to comprehensively address the problem of mismatches between a customer's scheduled and actual deliveries of power." Ex. CE-1 at 11. Michigan Systems rebut this argument by pointing to the successful operating experience under the COAs. MS R.B. at 58.

Furthermore, Michigan Systems argue that penalizing the utility for inadvertent energy exchanges by labeling them as energy imbalances has been detrimental to its operations and is unjustified. MS I.B. at 177. According to Mr. Cooper, the MCCP was forced to implement less efficient operating strategy in order to avoid the Energy Imbalance charges. Ex. MS-1 at 14. CECo's proposed penalties create strong incentives for MCCP to generate more energy than it needs in order to avoid the "greater evil" of Unauthorized Use charges and thus incurs the "lesser evil" of providing free energy to CECo. MS I.B. at 178. Michigan Systems argue that they would prefer to target their inadvertent energy exchanges at zero, but they have been unable to do so since the Energy Imbalance and Unauthorized Use charges were implemented. Id. at 178-179; see Ex. MS-2.

Additionally, Michigan Systems and City of Holland argue that these charges are discriminatory. MS I.B. at 179; Holland I.B. at 22. They contend that CECO's charges are discriminatory because the operations of the MCCP and those of the City of Holland and are essentially the same as those of the MECS, yet CECo has not eliminated the inadvertent energy exchanges with MECS. Id. Neither MECS nor any other control area has been able to completely avoid inadvertent interchange.

On cross-examination, CECo's witness Waits testified that CECo has continued the inadvertent energy agreements with other entities such as Detroit Edison, Ontario Hydro, Toledo Edison, American Electric Power, and Northern Indiana Public Service. Tr. at 1101. Michigan Systems claim that CECo's refusal to reinstate inadvertent energy exchange provisions with the MCCP violates the Commissions's requirement that transmission customers be treated on a comparable basis to the transmission provider itself. MS I.B. at 182, citing Order 888 No. at 31,703.

Staff argues that many of Michigan Systems and City of Holland's problems can be cured by eliminating CECo's penalty provisions, implementing the deviation bandwidth, requiring CECo to provide notice of imbalances sooner, and permitting a period of 30 days for returns in-kind. Staff I.B. at 75. Staff contends that CECo's treatment of mismatches between schedule and load as energy imbalances are consistent with Order No. 888, but that mismatches between generation and load are not covered under the Energy Imbalance Service provision. Staff R.B. at 55, citing Order No. 888-A at 30,230.

City of Holland further contends that Staff's proposed modifications, although warranted, do not extend far enough to address the actual physical operations of the utilities. Holland I.B. at 10-11. Mr. Cooper recommended that inadevertent energy exchanges should be reinstated for MCCP in order to achieve comparability. MS I.B. at 183; see Ex. MS-1 at 31-33. Michigan Systems argue that elimination of the capacity charges alone will not fix the comparability problem because MCCP would remain subject to excessive charges for energy, confiscation of energy delivered to CECo, and other costs and burdens that neither CECo nor the MECS control area have to bear. MS I.B. at 183.

Ruling on Application of Energy Imbalance to Customers Following Load:

Many of the problems associated with CECo's proposal not to offer MCCP reinstatement of "in-kind" return of inadvertent energy imbalances are cured by the rulings on related issues above dealing with the proposed capacity charge penalty and rate issues for Energy Imbalance Service. However, as argued by City of Holland and MS, there remains the issue whether MCCP is nevertheless entitled to comparable treatment to other control areas interconnected to CECo.

Factors favoring MS and City of Holland's position include: (1) MCCP and the City of Holland operate as control areas, even though not recognized as such by NERC (See Exs. MS-1 at 8-10; H-1 at 13); (2) the predecessor operating agreements and tariff provided for "in-kind" return of inadvertent energy exchanges and operated successfully; (3) substitution of Energy Imbalance Service charges has resulted in operational inefficiencies, including the provision of free energy to CECO, in attempting to avoid onerous penalties (See Ex. MS-2); and (4) CECo interchanges with utilities and MECS are governed by inadvertent exchange arrangements.

On the other hand, CECo's proposal is supported by the following arguments: (1) neither MCCP nor City of Holland is a NERC-recognized control area; (2) Order No. 888 does not require retention of operating agreements offering "in-kind" return for inadvertent energy exchanges; (3) MS and Holland are able to control the flows of power between them and CECo; (4) opportunities may exist enabling transmission customers to "game" exchanges so that lower cost energy replaces higher cost energy; and (5) Order No. 888 provides a comprehensive regime to address the problem of mismatches between a customer's scheduled and actual deliveries of power, relying on Energy Imbalance Service charges.

Whether or not MCCP or Holland are NERC-certified control areas seems beside the point, recognizing that MECS itself is not a NERC-certified control area. The important consideration is that these entities operate like control areas. The predecessor agreements similarly seem beside the point because the Commission embarked upon a fundamentally new open access transmission market structure when it adopted Order No. 888 and its progeny.

The more important considerations are the arguments surrounding comparability, inefficiencies and potential gaming. Turning first to the latter point, I am persuaded that the gaming issue is not a significant concern. Experience under the pre-existing system has been that gaming was not a problem. While one can posit that, under a new competitive regime, opportunities might arise and be seized upon to manipulate exchanges to one's advantage, the Commission's complaint procedures are available to deal with such occurrences if they do arise. As to comparability, it seems fundamentally unfair that CECo offers "in-kind" return for inadvertent energy exchanges to MECS and other utilities, but will not do likewise for MCCP. That the Energy Imbalance Service penalty regime has forced ineffiencies on MCCP's operations because of the unavailability of a comparable service from CECo, provides good reason to question CECo's premise that Energy Imbalance Service is the only way to handle the mismatch problems with its customers. I conclude that CECo has not demonstrated that its proposal to require Energy Imbalance Service for its customers that follow load, like MCCP and the City of Holland, is just and reasonable.

ISSUE 8 F -- Energy Imbalance Service - Forced Generation Outages

CECo would apply the Energy Imbalance Service provisions of its OATT to energy shortfalls triggered by a loss of customer generation. CECo I.B. at 89. CECo contends that a forced outage at a customer's local generator behind the transmission provider's metering facilities that is not promptly covered will appear as a mismatch between scheduled deliveries and actual load. Given that the information as to the source of the problem is known only to the customer, CECo claims that a "no fault" concept should be applied by administering Energy Imbalance Service charges in such situations. To do otherwise, CECo contends, would require it to undertake "detective work" to determine if the mismatch between scheduled deliveries and load was caused by a forced generator outage, as opposed to many other possible contributing factors. Id. at 91.

MS argues that Energy Imbalance Service and the charges for exceeding the deviation band are intended to encourage good scheduling practice on the part of transmission customers to meet load variations. See Order No. 888-A at 30,232. Accordingly, MS contends, Energy Imbalance Service should only apply when the difference between scheduled deliveries and actual deliveries under the OATT can be remedied by good scheduling practice. It should not apply, MS maintains, if good scheduling practice could not have avoided the difference between scheduled and actual deliveries, such as when a generator forced outage caused the imbalance. MS I.B. at 185.

MS further points to the testimony of CECo witness Rasmussen, where he agreed that it was his understanding of Order Nos. 888 and 888-A that the occurrence of a mismatch between generation resources and load due to a failure of a generator to respond would not trigger Energy Imbalance Service obligations. Tr. at 790-91. While Mr. Rasmussen later indicated that CECo would treat such a shortfall as being subject to Energy Imbalance Service, MS contends that such a result is inconsistent with Order No. 888-A. MS I.B. at 185.

Staff agrees with MS that CECo would violate the policies expressed in the Order No. 888 series of orders if it applies Energy Imbalance charges to situations involving generator outages. Staff calls attention to the following language in Order No. 888-B at 62,092: "if the emergency is the cause of the customer's energy imbalance, that is, the transmission provider is unable to deliver the scheduled energy, the customer should not be responsible for paying an Energy Imbalance Service penalty." Staff further cites Order No. 888-A at 30,233: "we believe that emergency situations caused by loss or failure of facilities should be addressed in the transmission customer's service agreement (or the generation supplier's separate interconnection agreement) and not as part of Energy Imbalance

Service."

CECo responds that the cited provisions were intended by the Commission to cover a specific situation related to remote generation located in a separate control area from the transmission customer and were not intended to apply to the facts presented here by MS. CECo continues to argue that its inability to monitor "behind the meter" local generation to distinguish generation failures from other events causing imbalances is critical and requires a "no fault" type solution. MS responds that CECo's "no fault" solution is in reality an "absolute liability" standard that would trigger Energy Imbalance Service charges regardless of cause, which is contrary to the guidance contained in the Order No. 888 series of orders.

Ruling on Energy Imbalance Service - Forced Generation Outages:

It seems clear that the Commission did not intend that imbalances created by forced generation outages be subject to Energy Imbalance Service penalty charges. Order No. 888-A at 30,233; Order No. 888-B at 62,092; Tr. at 790-91. CECo's protest, that these determinations were limited to the factual situation addressed and that the instant facts are not in accord, is unpersuasive. The Commission's language is clear, and the policy implications apparent. In addition, MS is correct that CECo's proposal is an absolute liability standard for imbalances, so that a penalty would apply, regardless of cause. Not only would that proposal do violence to the Commission's policy announced in Order No. 888 and related subsequent orders, but it would be per se unjust and unreasonable. Moreover, the practical constraints which concern CECo seem capable of resolution through normal communications channels. Detective work should not be required to ascertain whether or not an outage has in fact occurred. For these reasons, CECo's proposal is rejected.

ISSUE 9 A -- Spinning Reserve Service - Revenue Requirement

ISSUE 9 B -- Spinning Reserve Service - Unit Rate Calculation

ISSUE 9 C -- Spinning Reserve Service - Purchase Obligation

The Company's proposed annual revenue requirement, unit rate calculation and purchase obligation for Spinning Reserve Service are set forth in Ex. CE-17 at 21-22. CECo proposes a revenue requirement of $712,605,000, an allocation factor of 1.65

percent, resulting in a monthly unit rate of $0.17/kW, and a purchase obligation of 1.50 percent of the customer's reserve capacity or network load. Staff proposes a slightly higher monthly rate of $0.19/kW because Staff uses the 1.69 percent allocation factor for Spinning Reserve Service, while CECo uses 1.65 percent. Staff also proposes a 1.69 percent customer purchase obligation for Spinning Reserve Service.

MS contends that a 1-CP denominator should be employed to calculate this rate and that Appalachian pricing should not be used to calculate short-term pricing.

Ruling on Spinning Reserve Service Issues:

The ruling on this issue is governed by issues previously decided. The revenue requirement will be determined on the basis of rulings made previously that affect that determination. The unit rate calculation proposed by Staff will be accepted as just and reasonable. The allocation factor proposed by Staff is the remainder of the 3.0 percent ECAR reserve requirement after deleting the 1.31 percent factor for Regulation and Frequency Response Service. Ex. S-8 at 13; see also Issue 7 above. For the reasons noted in the ruling on Regulation and Frequency Response Service, Staff's approach is preferable to the arbitrary allocation preformed by CECO. For the same reason, Staff's proposal for a customer service obligation of 1.69 percent will be accepted over the CECo alternative of 1.50 percent. [35]

ISSUE 10 A -- Supplemental Reserve Service - Revenue Requirement

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35 / Staff's also correct that, under the provisions of Order No. 888 at 31,961, CECo should set forth in its tariff the customer purchase obligation percentage. Staff I.B. at 78.

ISSUE 10 B -- Supplemental Reserve Service - Unit Rate Calculation

ISSUE 10 C -- Supplemental Reserve Service - Purchase Obligation

CECo proposes to base the rate for Supplemental Reserve Service on a revenue requirement of $712,605,000, which includes all generation, except nuclear. Ex. CE-17 at 22. Staff, on the other hand, proposes a revenue requirement for this service of only $6,967,821, which includes only CECo's combustion turbine peaking units. See Ex. S-36.

CECo argues that Staff's proposal is based upon Staff witness Smith's "cryptic assumption that only CECo's combustion turbine generating units should be allocated to this service". CECo I.B. at 95. CECo witness Waits testified that all of CECo's dispatchable generation is capable of supplying operating reserves and that 50 percent of its operating reserves should be assigned to Supplemental Reserve Service. Exs. CE-68 at 8-10; CE-17 at 15. He argued that Staff witness Smith's definition of CECo units allocable to this function is far too restrictive. Mr. Waits also argued that, while combustion turbines are the least costly units to install from the standpoint of capital cost, they carry the highest fuel cost when operating. Ex. CE-68 at 9. Since fuel costs are not included in the revenue requirement for this service, Mr. Waits contended that Staff's proposal to base the rate only on combustion turbine investment would vastly understate the true cost of providing that service from combustion turbines. Id. CECo further observes that the Staff-proposed rate is far below rates for this service advocated by Staff in Northern Indiana Public Service Co., 79 FERC ¶ 63,009 at 65,117 (1997).

Staff responds that it based its proposed rates for this service on the costs of the particular units used to provide the service at issue for this particular utility. This explains why its position in other cases may have been quite different. Staff R.B. at 57. Staff further claims that its rate proposal here is not out of line with rates for similar services proposed by other utilities in Open Access Transmission Tariffs, such as that of IES Services, Inc., where that company proposed a $0.04/kW monthly charge for Supplemental Reserve Service. Allegheny Power System Inc., et al., 80 FERC ¶ 61,143 at 61,541 (1997). Staff goes on to argue that the Commission defined supplemental reserve as capacity that can respond to a contingency situation, but that is usually available within ten minutes, rather than immediately. According to Staff, the Commission indicated, in Order No. 888 at 31,708, that these reserves are provided by generating units that are on-line, but unloaded, or by "quick-start" generation. CECo has not, argues Staff, shown that all of its generating units fall into the category of "on-line but unloaded." Staff claims to have met the Commission's definition by including only the units most likely to provide this service. Ex. S-8 at 16.

CECo proposes a monthly unit rate of $0.34/kW based upon an allocation factor of 3.3 percent. The equivalent monthly rate advocated by the Company is $10.30/kW ($0.34 divided by .033) Staff proposes a monthly charge of $1.29/kW, with an allocation factor of 3.0 percent and using the cost and associated capacity of only CECo's turbine generator units.

CECo proposes that the customer purchase obligation for this service should be 3.3 percent and Staff proposes that it be set at 3.0 percent. Staff also asks that CECo be instructed to include in its OATT, language that would allow the customer to determine the amount of this service that must be purchased. Staff I.B. at 80; see Ex. S-8 at 17-18.

Ruling on Supplemental Reserve Service Issues:

The supplemental service revenue requirement should be based upon the costs of units that are most likely to provide the service. Here, Staff has made a persuasive case for basing this rate on the Company's combustion turbine generating units as opposed to all of the Company's generation (except nuclear), as advocated by CECo. CECo has failed to show that basing this rate on every unit in its system is consistent either with rational pricing policy or the Commission's Order No. 888. Specifically, CECo has not demonstrated that all of its units fall into the category of plants "on-line, but unloaded" referred to by the Commission in Order No. 888 at 31,708. In such a circumstance, it would be erroneous to base a rate for supplemental service on the full range of CECo's generating resources. Accordingly, Staff's proposal is adopted. Neither is CECo's fuel cost argument persuasive. As Staff observes, fuel costs may be recovered as the units are used to produce energy. There is no real danger of cost underrecovery.

The unit rate and purchase obligation percentage should track Staff's proposals, as well. Further, Staff's proposal that CECo be required to add language to its tariff informing customers of the purchase obligation is also adopted as reasonable and necessary.

CONCLUSION

It is concluded that the just and reasonable rates and the tariff provisions affecting such rates are and will be those that are in conformity with the findings and conclusions set in this decision.

ORDER

IT IS ORDERED, subject to review by the Commission on exceptions or its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty days of the issuance of the Final Order of the Commission in this proceeding, Consumers Energy shall file revised tariff sheets in accordance with the findings and conclusions of this Initial Decision, as adopted or modified by the Commission.

William J. Cowan
Presiding Administrative Law Judge

UNITED STATES OF AMERICA86 ferc • 63,004
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company	)	Docket Nos. OA96-77-000
	)	ER97-1502-000
	)	and ER98-1247-000

INITIAL DECISION

(Issued January 14, 1999)

APPEARANCES

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William J. Cowan, Presiding Administrative Law Judge

PROCEDURAL BACKGROUND

This proceeding originally stems from the issuance by the Commission on April 24, 1996, of Order No. 888, requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to, among other things, have on file open access transmission tariffs that contain minimum terms and conditions of non-discriminatory service. 1/ The compliance filings were to be made by July 9, 1996. Utilities subject to this requirement were divided into Group 1 (utilities that had tendered for filing open-access transmission tariffs before the date of issuance of Order No. 888) and Group 2 (utilities that had not tendered pre-Order No. 888 tariffs). Additionally, Order No. 888 provided for a blanket suspension for all Group 1 filings that included new rate proposals, of which this is one, and directed that they go into effect, subject to refund, on July 9, 1996. Pursuant to the Commission's order, Consumers Energy Company ("Consumers Energy", "CECo" or "the Company") filed its open-access tariff in Docket No. OA96-77-000 on July 9, 1996. On January 29, 1997, the Commission accepted the non-rate terms and conditions of the Tariff without ordering an evidentiary hearing. American Electric Power Service Corp., et al., 78 FERC • 61,070 at 61,269 (1997). By Order issued July 31, 1997, the Commission set Consumers Energy's and other Group 1 public utilities' rates for hearing. Allegheny Power System, Inc., et al., 80 FERC • 61,143 (1997).

On January 31, 1997, Consumers Energy, in Docket No. ER97-1502-000, filed an unexecuted transmission service agreement ("TSA") and a network operating agreement ("NOA") for service to the Municipal Cooperative Coordinated Pool ("MCCP") 2/ under Consumers Energy's open access transmission tariff. MCCP protested the unexecuted TSA and the NOA and on April 1, 1997, the Commission accepted the agreements for filing, suspended and made them effective subject to refund, and established hearing procedures. Consumers Power Co., 79 FERC • 61,001 (1997). On August 20, 1997, Chief Administrative Law Judge, Curtis L. Wagner, Jr., issued an order consolidating Docket No. ER97-1502-000 with Consumers Energy's on-going open access proceeding in Docket No. OA96-77-000.

1/ See Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. and Regs., Regulations and Preambles 1991-1996 • 31,036 (1996) ("Order No. 888"), Order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. and Regs. • 31,048 ("Order No. 888-A"), Order on reh'g, Order No. 888-B, 81 FERC • 61,248 (1997), ("Order No. 888-B"); Order on reh'g, Order No. 888-C, 82 FERC • 61,046 (1998)("Order No. 888-C").

2/ MCCP is comprised of the Michigan Public Power Agency ("MPPA") and the Wolverine Power Supply Cooperative, Inc. ("Wolverine").

On December 30, 1997, Consumers Energy filed in Docket No. ER98-1247-000, an unexecuted TSA for service to the MCCP from January 1, 1998, to December 31, 1998, to replace the expired comparable TSA filed in Docket No. ER97-1502-000. In all material respects, this TSA had the same terms and conditions as the prior unexecuted TSA in Docket No. ER97-1502-000 filed by Consumers Energy for service to MCCP from January 1, 1997 to December 31, 1997. On February 27, 1998, the Commission issued an order consolidating the filing in Docket No. ER98-1247-000 with, and making it subject to the outcome of, the ongoing consolidated proceedings in Docket Nos. OA96-77-000 and ER97-1502-000. Consumers Energy Co., 82 FERC • 61,206 (1998).

Active participants in this proceeding include Consumers Energy, the Michigan Systems ("Michigan Systems" or "MS"), 3/ the Association of Businesses Advocating Tariff Equity ("ABATE"), the Board of Public Works of the City of Holland, Michigan ("Holland"), The Michigan Public Service Commission ("MPSC"), Edison Sault Electric Company ("Edison Sault"), and Commission Staff ("Staff"). On March 13, 1998, pretrial briefs were filed by all active parties, with the exception of the MPSC, which filed a statement in lieu of pretrial brief. A hearing was conducted commencing March 17, 1998 and concluding April 2, 1998. Subsequent to the hearing, initial and reply briefs were filed on May 21, 1998 and June 19, 1998, respectively by all active parties except the MPSC.

On June 29, 1998, Chief Administrative Law Judge Curtis L. Wagner, Jr. designated the undersigned to substitute for Administrative Law Judge Debra Morriss, who was no longer available to serve, and directed that I take further actions in these premises.

This initial decision follows the sequence of the Chart of Issues developed in this proceeding. The positions of the parties on each issue are set forth first, followed by a ruling which contains an evaluation of the evidence and the decisional rationale. While most noteworthy arguments and supporting references are discussed, the omission of references to particular arguments or record citations does not mean that they have not been considered. All arguments raised and evidence presented have been evaluated with care.

ISSUE 1 A -- Consumers Energy's Facilities That Can Be Deemed Part of Rate Base

3/ Michigan Systems consist of the MPPA, Michigan South Central Power Agency, Wolverine, and Michigan Public Power Rate Payers Association ("MPPRPA").

Michigan Systems challenge the inclusion by CECo in its rate base of facilities, primarily 23 kV and 46 kV facilities and higher voltage radial lines, which they contend have not been shown to provide service to transmission customers under CECo's Open Access Transmission Tariff ("OATT") to any greater extent than comparable facilities owned by transmission customers. MS I.B. at 5. Allocation of the costs of such facilities to CECo's transmission customers who do not purchase power from CECo or otherwise use such facilities subsidizes CECo's service to its own power customers at the expense of transmission customers who do not require the facilities for service under the OATT, MS contends. Id. at 5-6.

To prevail on the issue of inclusion of these low voltage facilities in rate base, MS argues that CECo must: (1) show that the facilities at issue are integrated into CECo's transmission plans or operations to serve the Company's power and transmission customers; and (2) satisfy the Commission's comparability standard. MS maintains that the Company has failed to satisfy either of these criteria. MS I.B. at 6-31.

The Company contends that it does not bear the burden of proof that each individual segment of its transmission system should be included in its rate base. CECo I.B. at 5. Its rate base claim here, CECo asserts, is predicated upon the historic rolled-in approach employed to develop its 1992 Open Access tariff, which in turn was based upon prior unbundled transmission tariffs going back to the 1980's. Id. The Company further points to the testimony of its witness, Erickson, who stated that all of CECo-owned transmission facilities are integrated into the plans and operations of the Company to serve its customers. Ex. MS-53; see also, Exs. CE-16 at 1; CE-29 at 4.

Staff argues that CECo has included in its rate base those facilities traditionally rolled into transmission rates by public utilities. Staff R.B. at 3. Staff claims that it is "unnecessary to unscramble the egg and review [CECo's] system on a facility-by-facility basis to ensure comparable treatment of Michigan Systems." Id. Staff points to the analysis of its witness Oxendine, who reviewed and identified the MS facilities that performed functions similar to those facilities rolled into CECo's rates, and are deserving of comparable treatment. Id.

According to MS, in order to recover the cost of its facilities through transmission rates, the transmission provider must demonstrate that the facilities claimed for inclusion in its rate base serve its power and transmission customers. MS I.B. at 6-9. CECo has failed to demonstrate, MS contends, that any single facility, or the facilities as a whole, provide transmission service, relying, instead, on the contention that the entire system provides service under the tariff. Id. at 7. MS cites references in the transcript to Company witness testimony where MS alleges CECo conceded that not all of its facilities are needed to serve transmission customers (Tr. at 180-82) and that many facilities play little or no role in serving transmission customers (Tr. at 372). Moreover, MS argues, CECo has failed to demonstrate that its facilities are integrated, and, accordingly entitled to "rolled in" rate base treatment. MS I.B. at 9.

Turning to its comparability argument, MS grounds its position here on the following language in the Commission's Order No. 888:

> We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

Order No. 888 at 31,743, n.452.

Also, MS cites the following passage from the Commission's Order No. 888-A:

> As we noted in FMPA II, this fundamental cost allocation concept applies to the transmission provider as well. Just as the customer cannot secure credit for facilities not used by the transmission provider to provide service, the transmission's provider cannot charge the customer for facilities not used to provide transmission service.

Order 888-A at 30,271, n.277, citing Florida Municipal Power Agency v. Florida Power & Light Company, 74 FERC • 61,006 at 61,010, n.48 (1996)("FMPA II").

MS claims that CECo currently rolls into its transmission rate base facilities whose purpose it is to deliver power from higher voltage bulk transmission facilities to its retail customers. Ex. MS-16 at 13. Such facilities, MS argues, play no role or very little role in serving transmission customers, but may be necessary for CECo to serve itself as a network customer. MS I.B. at 10. According to MS, transmission customers also pay the costs of their own facilities that similarly serve to deliver power from higher voltage bulk transmission facilities to retail customer service areas. Id. CECo, however, does not share in the costs of such facilities, MS maintains. This asserted lack of comparability is at the heart of MS' argument here. According to MS, CECo integrates all of its load using the transmission grid, and seeks to allocate the costs of transmission facilities serving loads among all customers, even if those facilities are not necessary to serve transmission customers. Id. In such circumstances, MS contends, all transmission facilities used to serve those loads, including customer-owned facilities, must be considered part of the transmission grid. Only then will comparability be maintained, MS asserts. Id. at 10-11.

Here, comparability requires either that CECo facilities that are not necessary to serve transmission customers be deleted from the rate base, or that customer-owned facilities supporting the grid receive appropriate credits, argues MS. However, MS maintains, neither CECo nor Staff studied whether CECo facilities included in rate base were required to serve transmission customers. MS contends that CECo and Staff treated CECo's facilities as the embedded or native facilities, while treating customer-owned plant as incremental, and putting individual customer facilities "through the wringer." MS I.B. at 11. MS goes on to argue that the so-called Megawatt-Mile ("MW-Mile") analyses performed by Staff and CECo fail to treat customer facilities comparably and provide no information about whether a line is important or necessary, only whether a specific line participates in a power transfer. Id. at 13. MS further argues that the CECo 46 kV system participated in certain modeled transactions to a lesser extent than MS' own facilities. Ex. S-30 at 7-10.

MS concludes that certain CECo facilities must be removed from rate base, unless customer-owned facilities that perform comparable functions receive appropriate credits. These facilities include generator step-up transformers and related substation equipment; radial lines; and facilities predominantly serving a local area function, such as subtransmission facilities which link CECo's bulk transmission system to its distribution substations. Ex MS-16 at 47-48; see also Ex. MS-21 at Sheet No. 2. MS contends that additional evidence of facilities appropriate for removal from CECo's rate base is set forth in testimony that Company witness Erickson presented in an MPSC proceeding to determine which facilities should be classified as transmission facilities for purposes of delivery of electricity purchased by retail electric customers. Ex. ABATE-16. There, Mr. Erickson testified that facilities that connect generators to the transmission grid should be re-classified as generation-related, and 138 kV radial lines that supply 138/46 kV substations, 138 kV to 46 kV and 138 kV to 23 kV substations and all 46 kV and 23 kV lines should be re-classified as distribution facilities. Id. at 7-13.

Ruling on Consumers Energy's Facilities That Can Be Deemed Part of Rate Base:

We deal here with MS' argument that the Company has not demonstrated that its facilities can be included in the rate base. First, CECo and Staff are correct that the Company is not required initially to demonstrate that all expenditures were prudent or that each and every item of plant in its claimed rate base properly belongs there. However, upon a showing of serious doubt about the prudence of particular expenditures by other case participants, or, by analogy, doubts about the proper inclusion of particular plant in rate base, the applicant has the burden of dispelling such doubts and proving that the expenditures were prudent or that the plant is properly in rate base. Minnesota Power & Light Co., 11 FERC • 61,312 at 61,644-5 (1980).

Here, use of the historic, rolled-in rate base is an acceptable point of departure for CECo. Its testimony that all of its transmission facilities are integrated into its plans and operations to serve its customers was not challenged by specific references to transmission lines or substations that are not used to provide transmission service. The record citations offered by MS to support its position fail to do so. At Tr. 180-82, the CECo witness was responding to hypothetical wheeling transactions where CECo's 46 kV transmission line was described as not a significant factor, and, at Tr. 372, the witness actually replied that all of the facilities are providing service to the Company's customers in some form.

However, the Company has petitioned the Commission for a declaratory order in Consumers Energy Co., Docket No. EL98-21-000 that would accept a determination of the MPSC as to which of its facilities should be classified as transmission facilities for purposes of delivery of electricity purchased by retail electric consumers. CECo has described the MPSC determination as follows:

> (1) With the exception of approximately 180 miles of radial 138 kV lines and associated facilities and retail meter facilities, all of CECo's facilities that transmit electricity at voltages of 120 kV or above should be classified as transmission facilities.
>
> (2) All of CECo's facilities that transmit electricity at nominal voltages of less than 120 kV, approximately 180 miles of radial 138 kV lines and associated facilities and all retail meter facilities, regardless of voltage, should be classified as local distribution facilities.
>
> (3) CECo's generator step-up transformers, lines and other facilities used to connect CECo's generating plants with its transmission system should be classified as generation facilities.

Staff I.B. at 7, citing CECo's letter dated January 22, 1998, in Docket No. EL-98-21-000.

Accordingly, that petition would give effect to some of the changes in rate base sought here by MS. I take notice that the Commission granted CECo's petition in a Letter Order issued July 29, 1998, concluding that certain facilities identified in that petition are State-jurisdictional local distribution facilities and others, also identified in the pleadings, are Commission-jurisdictional transmission facilities. The Commission also decided not to delay action on CECo's request pending the filing of revised rates, as had been requested by MS in that docket. Instead, the Commission has stated that, after the transmission-related costs have been identified, rates should be developed to reflect those costs. Accordingly, the rate base initially claimed by CECo in the instant dockets must now be adjusted to account for the subsequent development concerning a re-classification of its plant in the MPSC proceeding, which the Commission has now accepted.

Claims relating to comparability, and the issue surrounding fair and equitable treatment of customer facilities in the new era of transmission policy ushered in by Order No. 888, are more appropriately considered in Issue 1 B, next following.

ISSUE 1 B -- Credits for Customer-Owned Facilities

Continuing its argument that credits should be received for facilities owned by network service customers on the grounds that such facilities are integrated into the plans and operations of CECo to serve its power and transmission customers, MS claims to have demonstrated that MCCP facilities qualify for credits under the provisions of Section 30.9 of CECo's OATT. MS I.B. at 34. It seeks $9.8 million ($13.5 million if Lansing becomes a network customer) annually in revenue credits from CECo for Michigan Systems' solely-owned transmission facilities that are connected to CECo's transmission system, contending that such facilities are integrated into the plans and operations of Consumers Energy to serve the power and transmission customers of CECo.

Section 30.9 of the OATT 4/ provides as follows:

> The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For

4/ This provision appears both in CECo's tariff and the Commission's pro forma tariff appended to its Order 888-A.

> facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

The Commission explained:

> The intent of section 30.9 of the pro forma tariff is that, for a customer to be eligible for a credit, its facilities must not only be integrated with the transmission provider's system, but must also provide additional benefits to the transmission grid in terms of capability and reliability, and be relied upon for the coordinated operation of the grid. Indeed, in the Final Rule we explicitly stated that the fact that the transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over these facilities.

Order No. 888-A at 30,271.

Also pertinent, is the following statement from the Commission's Order No. 888:

> The presumption of many commentators that a customer's subscription to transmission service somehow transforms the provider's and customer's systems into an expanded and integrated whole to the mutual benefit of both is not a valid one. As we ruled in Florida Municipal Power Agency v. Florida Power & Light Company, ("FMPA"), it must be demonstrated that a transmission customer's transmission facilities are integrated with the transmission system of the transmission provider. Specifically, we stated that:
>
>> The integration of facilities into the plans or operations of a transmitting utility is the proper test for cost recognition in such cases. The mere fact that a section 211 requestor has previously constructed facilities is not sufficient to establish a right to credits.

> The fact that a transmission customer's facilities may be interconnected with a transmission provider's system does not prove that the two systems comprise an integrated whole such that the transmission provider is able to provide transmission service to itself or other transmission customers over those facilities - a key requirement of integration.

Order No. 888 at 31,742-43. (Footnotes omitted; emphasis in original). 5/

Another Commission decision is also pertinent here. In FMPA II, the Commission stated:

> We decline to grant FMPA the requested credits; likewise we will deny its conditional request for rehearing. We reject FMPA's argument that, because it must pay a rate reflecting the cost of all of Florida Power's transmission facilities, it is entitled to a credit reflecting the cost of all of FMPA's transmission facilities. The final order did not direct a merging of the parties' transmission systems or the operation of a joint transmission network.
>
> *****
>
> While the FMPA facilities may serve a transmission function on the FMPA side of the interconnection point between FMPA and the Florida Power system, they are not used by Florida Power to provide transmission service to FMPA or any other party. Nor are they used to transmit Florida Power's power to its non-FMPA customers.
>
> *****
>
> The fact that the Ft. Pierce/Vero Beach line constitutes a parallel path and is subject to occasional loop flow does not, in and of itself, compel a conclusion that the line now operates as part of the Florida Power integrated transmission network.
>
> *****
>
> Also, while the Ft. Pierce/Vero Beach line may be redundant to certain facilities comprising the Florida Power network, unneeded redundancy provided by FMPA cannot qualify for a credit any more than an unnecessary Florida Power transmission facility could

5/ FMPA is found at 67 FERC • 61,167 (1994).

> qualify for cost recovery. In sum, because the Ft. Pierce/Vero Beach line is not used by Florida Power to provide transmission service to itself or others in the Florida Power control area, its existence has no effect on Florida Power's cost of providing service to any Florida Power customer, including FMPA.

74 FERC at 61,009-10.

Additionally, Michigan Systems point to the footnote on comparability provided by the Commission in Order No. 888 at 31,743, n.452, to wit:

> We caution all transmission providers that while our discussion here addresses the requirements necessary for a customer's transmission facilities to become eligible for a credit, the principles of comparability compel us to apply the same standard to the transmission provider's facilities for rate determination purposes.

This precedent sets the stage for Michigan Systems' argument that certain MCCP facilities are integrated into CECo's plans or operations to serve CECo's customers, in the manner contemplated by the Commission in its various statements setting forth guidance on what it takes to qualify for a customer facilities credit. 6/ MS further argues that the MCCP transmission facilities provide measurable benefits.

To support its claim of integration, MS contends that the facilities at issue are necessary to serve a CECo network customer, meaning MCCP, and that they integrate the MCCP loads with other loads and resources connected to the CECo transmission system. If credited, the facilities would continue to serve CECo's power and transmission customers as they do already. MS I.B. at 35-36.

MS asserts that these facilities provide the following functions:

> (1) They convey power and energy from MCCP member-owned generation sources to load aggregation points on the transmission grid for delivery to other points on the transmission grid;

6/ The MCCP transmission facilities for which credit is claimed include the "MCP Integrated System," which includes the facilities of Wolverine, Grand Haven, Traverse City and Zeeland and the "Lansing Integrated System." Ex. MS-16 at 25-29.

> (2) They convey power and energy from MCCP member-owned generation sources to the transmission grid for delivery to points of interconnection to other electric systems;
>
> (3) They convey power and energy from other generation sources through interconnection points to load aggregation points on the MCCP member systems;
>
> (4) They provide parallel paths in order for the integrated system (CECo plus MCCP) to continue operating despite outages of transmission facilities along other paths; and
>
> (5) They produce and convey to the grid reactive power to control voltage on the transmission grid.

MS I.B. at 38.

MS contends that the MCCP facilities that make up the MCP Integrated Systems are functionally integrated in a manner comparable to CECo facilities which perform much the same mission as the MCCP facilities described above. MS witness Reising concluded that the transmission facilities owned by the MCCP member systems integrate network loads, generating resources and interconnections with other parties. He further contends that if Lansing was included as a network load under the MCCP network service, its facilities would also qualify for a credit for the same reason. Both the MCP and Lansing Integrated Systems are interconnected to CECo at multiple locations (eleven for MCP and two for Lansing), MS maintains. As a result, MS argues, power flows across these interconnections are bilateral. Power can and does flow across the MCP and Lansing systems, into some interconnections with CECo and out of other interconnections from CECo, claim Michigan Systems.

MS argues that the credit requirements set by the Commission have been satisfied in that customer-owned facilities of MCCP provide service to CECo's transmission customers, specifically MCCP, which is a CECo transmission customer. Further, MCCP facilities support the transmission grid and are available to other transmission customers under CECo's OATT, fulfilling the integration requirement that the facilities seeking credit provide service to other transmission customers, MS contends.

MS further claims that other indicia of integration are apparent, including: (1) facilitating the delivery of power produced by generators or purchased from interconnected systems to loads; Compare Ex. MS-16 at 35 and Tr. at 335-37 to Tr. at 188-89, 203-05; see also Ex. MS-23; (2) facilitating off-system sales; (3) permitting reliance on other systems for reserves; and

(4) permitting delivery of power from one point on the grid to another point. MS I.B. at 41.

Michigan Systems claim to have proved the integrated nature of the MCP and Lansing Integrated Systems through load studies performed using CECo's own power flow model. Ex. MS-16 at 33. Regarding MCP, three ties were analyzed including ties between Wolverine and CECo in the Odin, Airport and Hersey areas. Two had flows normally from CECo to Wolverine. Hersey normally delivered power from Hersey to CECo. Id. After a line outage near each tie, the direction of the flow reversed on two of the ties and all three delivered power to CECo. These bi-directional flows evidence integration, according to MS witness Reising. Id. at 33-34. MS similarly analyzed the Lansing Integrated System using the CECo base case. Michigan Systems contend that the Lansing system picked up flows as a result of the outage of CECo's facilities. MS I.B. at 42-3; see also Ex. MS-25 at 2.

A study of the effect of a constraint along CECo's AEP interface also demonstrates the integrated nature of the MCCP and CECo facilities, Michigan Systems maintain. Positing the import into the CECo system of 735 MW over the two ties with AEP, Mr. Reising demonstrated the effect of an outage at one of the ties. MS I.B. at 43; see Ex. MS-26 at 2-3. The remaining tie would experience an increase in loadings from 44.2 percent to 95.1 percent. By increasing generation at Lansing by 75 MW, the loadings on the in-service tie drop from 95.1 percent to 93.3 percent. Greater increases in generation produce more reductions in line loadings, Mr. Reising maintains. This represents significant relief that could not be realized without the MCCP transmission facilities, he contends. MS I.B. at 43.

Turning to its argument that the MCCP facilities provide measurable benefits in terms of capability, reliability, and coordinated operation of the grid, MS first contends that the criteria against which its claim of measurable benefits is to be judged should be comparable to that employed to judge the benefits of the transmission provider's facilities. Its facilities would be available for service under CECo's OATT. Ex. MS-16 at 45. MS maintains that this would eliminate undesirable rate pancaking, encourage electrical coordination and reliability, and would lead to a more efficient grid. See Ex. MS-1 at 47-48; Tr. at 1638-39, 767-768; Ex. MS-34 at 18; Tr. at 1675-76. Access to generation owned or controlled by MCCP also benefits CECo's power customers to the extent CECo needs power, MS argues. Further benefits take the form of reduced transmission investment; an increase in the loads against which the costs of the system can be allocated (See Ex. MS-16 at 36, Ex. MS-34 at 9, 16, 17-18); and coordinated grid operation and reliability through re-dispatch opportunities and the availability of alternate-sourced generation (See Exs. MS-16 at 35, 38-40; MS-34 at 6; MS-16 at 39).

MS further argues that comparability is itself a basis for the award of credits. Claiming to have demonstrated that the facilities for which it seeks credit are comparable to the ones that CECo claims are integrated into its plans and operations, MS sees a compelling basis for the assignment of credits for MCCP facilities. MS I.B. at 71-77. Yet another basis for its claim of entitlement to credits here for MCCP facilities is the Commission's adoption of load ratio share pricing for network service under the OATT, citing to Order No. 888 at 31,736. Under this theory, credits are not predicated merely upon interconnection, they are based upon the use of transmission to integrate the customers' load and resources, according to Michigan Systems. MS I.B. at 82-83.

Moreover, MS argues, the absence of credits, in the context of load share pricing, injures MCCP. MS I.B. at 83-86. It contends that CECo's failure to recognize the Lansing transmission as eligible for credits while insisting that the Lansing load be designated as network load under network integration service created the necessity for MCCP to exclude the Lansing loads from the rest of the MCCP's integration activities or incur unreasonably high transmission charges. See Ex. MS-24. This has forced MCCP to resort to the purchase of short-term point-to-point transmission from CECo. Had MCCP included Lansing under Network Integration Transmission Service, MCCP would have incurred an annual cost of approximately $6,200,000. Ex. MS-1 at 38.

Michigan Systems have calculated credits, which it claims at Exs. MS-16 at 45-47 and MS-30. MS contends that no party has offered evidence disputing these calculations and urges their adoption. MS I.B. at 88.

Consumers Energy contends that the Commission rejected, in Order No. 888-A, the broad interpretation of integration urged here by MS when it reconsidered the original pro forma tariff language of Section 30.9. As noted above, the Commission stated that, to be eligible for a credit, additional benefits to the transmission grid in terms of capability, reliability and coordinated operation of the grid would be required, in addition to integration with the transmission provider's system.

CECo's position is that only certain 345 kV transmission lines jointly-owned by CECo with MCCP's members MPPA and Wolverine would qualify for a credit, because no other MCCP facilities provide the additional capability or reliability benefits to Consumers Energy's transmission grid or are relied upon by CECo in any way to provide transmission service to itself or others.

CECo offers the rebuttal testimony of Mr. Erickson, an Executive Engineer in the Company's Transmission Planning and

Performance Division. He analyzed MS witness Reising's testimony and, after conducting load flow studies, concluded that neither the MCP nor Lansing Integrated Systems of MCCP are integrated into the plans and operations of CECo to serve its power and transmission customers. Ex. CE-73 at 14, 17. Regarding the MCP Integrated System, he made the following claims to support his position:

> MCP has only one transmission line operated at voltages of 138 kV or above which is not radial to 138/69 kV transformers -- the so-called "Airport Line," a WPSC facility extending from CECo's Livingston Substation to CECo's Airport Substation.
>
> All ten 138 kV interconnection systems between CECo and the MCP Integrated System were installed at the request of MCCP or its predecessors to receive power from CECo's system.
>
> Construction of interconnections with the MCP Integrated System did not eliminate the need for any new CECo transmission facilities.
>
> CECo can supply its own load and the load of other CECo transmission customers without reliance on the MCP Integrated System.

Ex. CE-73 at 16.

Noting that the Airport Line is considered by Staff as potentially eligible for a credit, Consumers Energy argues that: (1) this line was not jointly planned to provide benefits to CECo; (2) the line was located and designed in way that was undesirable to CECo; (3) the line does not improve CECo's ability to supply load to Alpena during a line outage contingency, but instead increased the load to be served under outage conditions; and (4) the line provides no benefit to CECo or other transmission customers from either a cost or performance perspective. Ex. CE-73 at 19-23.

Further, Consumers Energy's witness Erickson contends that the backbone 69 kV portion of the MCP Integrated System does not have the capability to transmit significant amounts of power. Id. at 22. Neither does the existence of the MCP system prevent violation of any CECo planning criteria or eliminate the need for new transmission facilities, the CECo witness contends. Id. at 22-24.

The Hersey 46 kV interconnection, requested by CECo, ceased to have any value to CECo upon completion of CECo's 138 kV facilities in 1992, and the Company has requested its retirement because it adds to its operating costs. Also, CECo contends that the MCP Integrated System is not useful to CECo in providing transmission across its system in power transfers such as from AEP to Ontario Hydro. Ex. CE-73 at 30-31. Moreover, CECo argues, the Lansing 138 kV line paralleling CECo's 138 kV Oneida to Delhi line is the equivalent of a redundant line, as demonstrated by load flow studies performed by Mr. Erickson. Id. at 34-38; see also Ex. S-30 at 19-21.

CECo claims that MCCP would actually assert a right to a payment from CECo if subtracting MCCP's credit under Section 30.9 from its CECo bill for Network Service resulted in a negative number. Thus, CECo contends that Michigan Systems' proposal for extensive credits would result in a bizarre anomaly -- CECo paying millions of dollars annually for the privilege of providing network service to the MCCP. CECo I.B. at 18; Tr. at 1394-5, 1449.

Staff's position is that a small portion of MCCP facilities qualify for a credit, but not the full amount requested by Michigan Systems. Staff I.B. at 5. Staff maintains that the "snapshot" load flow analysis provided by Michigan Systems, where four of the thirteen interconnection points between member systems of MS and Consumers Energy were studied, does not demonstrate that the claimed facilities are integrated with CECo's transmission facilities. Tr. at 1683. There is, according to Staff, no evidence that Michigan Systems' facilities would benefit the entire integrated transmission system. Nor do redundant facilities meet the Commission's revenue credit criteria, argues Staff. Allowing credits for facilities that are not integrated and provide no system-wide benefit would result in an improper cross-subsidization of those facilities by other transmission users, Staff claims. Tr. at 1694.

Staff has identified 60 miles of 138 kV lines and related transmission facilities owned by WPSC (the Airport line) that may be used to serve the integrated network load and, therefore, are eligible for a credit. See Exs. S-30; S-31. Additional MS facilities may qualify for credit in the future, Staff contends, particularly if Lansing becomes a network customer. Staff I.B. at 7.

Staff is also critical of MS' complaint regarding a lack of comparable treatment in the analysis of CECo's facilities, which MS says have been accorded presumptive validity whereas MS facilities were "put through the wringer." Staff says that Consumers Energy includes in its rate base those facilities traditionally rolled into transmission rates by public utilities. To review a transmission provider's facilities on a facility-by-facility basis would be an incredibly complex and unworkable job, according to Staff. Tr. at 1695. Staff claims that there is no need to engage in any unscrambling of CECo's facilities to ensure comparable treatment of Michigan Systems. Staff I.B. at 8. Finally, Staff makes the same observation that CECo did, i.e., that MS claims far more in credits from CECo than it pays to the Company for transmission service. This anomaly, Staff claims, would unjustifiably burden CECo's other customers. Id.

Edison Sault urges denial of MS' request for credits, contending that Michigan Systems have failed to produce any evidence that would clearly demonstrate that their facilities are integrated with the planning and operation of CECo's transmission facilities. ES I.B. at 13. MS fails to pass the Commission's integration test, Edison Sault argues, contending that mere interconnection is not enough, that MS is required to prove the two systems comprise an integrated whole. Id. This would entail, according to Edison Sault, that the transmission provider be able to provide transmission service to itself or other customers over those facilities. Id. The MS member facilities are duplicative and not needed by CECo to deliver power, Edison Sault contends. Id. at 13-14. MS witness Reising's test for comparability -- that comparable facilities are all customer owned facilities that function in the same manner as CECo's rate based facilities -- is far too liberal, according to Edison Sault. Id. at 14. Under such a construction, there would be no way to delineate facilities that truly warrant credits. Such a conclusion would also burden Edison Sault, it contends, because CECo does not need MCCP's facilities to deliver power to Edison Sault. Id. at 15.

In reply, MS argues that CECo seeks to have its cake and eat it too, in that it presses for inclusion in rate base on a rolled in basis of all of its own facilities classified as transmission facilities under the Commission's Uniform System of Accounts, yet would apply a wholly different standard to judge whether customer facilities are entitled to a credit. MS R.B. at 3. MS points out that CECo defines its grid by recognizing the integrated nature of all facilities necessary to serve its customers. Under that definition, MS contends, customer facilities should be entitled to the same treatment. Otherwise, Michigan Systems claim, comparability will not be achieved. Id. at 5.

MS dismisses CECo's arguments that FMPA II supports the Company's position. MS points to the Commission's language at 74 FERC • 61,010, n.48: "This fundamental cost allocation concept applies to Florida Power as well as FMPA. Just as FMPA cannot obtain credits for facilities not used by Florida Power to provide service, so Florida Power cannot charge FMPA for facilities not used to provide transmission service." This, MS argues, makes clear that comparability is the rule. MS goes on to argue that in FMPA II, the Commission sought balance among the definition of the grid, the inclusion of network load to pay for network service, the allowance of credits for customer transmission, and the inclusion of company transmission investment in rate base. MS R.B. at 7. A similar approach here would, MS contends, result in credits for MS' ownership portions of the 345 kV grid and for facilities that provide direct benefit to the grid, such as those proposed to be included by Staff. Id.

Contending that there are alternate ways to achieve comparability, Michigan Systems suggest that CECo's position fails in that it would apply its expanded rate base, yet define the grid in a very different way to calculate credits for customer facilities.

MS is also critical of what it describes as the "CECo-lite" position advocated by Staff, where some MS facilities would be entitled to credits, but where no load studies were performed to validate that all of CECo's facilities contribute to the grid. MS. R.B. at 11-12. Further, MS contends that many of Staff's positions are off-the-mark or wrong. MS maintains:

> It does not seek $13,548,445 in credits because that number includes Lansing becoming a network customer, which it is not.
>
> Staff's statement that MS seeks credit for 1,600 miles of transmission lines is incorrect because that figure includes the Wolverine facilities for which it does not seek credit.
>
> Staff's characterization of MS load flow study as a "snapshot" implies inappropriately that the studies are not representative.
>
> Staff's implication that MCCP claims credit for redundant facilities is not based upon a study to determine whether it is MCCP's or CECo's facilities that are redundant.
>
> Staff's limitation of credits is based upon faulty assumptions.
>
> Staff's allegation that MS has failed to provide the cost of facilities to determine appropriate credits is wrong, citing to Exs. MS-34 at 15, and MS-35.
>
> There is no conceivable basis upon which to disallow credits for the Lansing facilities, assuming Lansing becomes a network customer, because those facilities provide a direct path through the transmission network.

MS R.B. at 15-17.

Responding to CECo's points, MS maintains that:

> In contending that the MCP Integrated System has only one transmission line operated at voltages of 138 kV or above that is not radial to 138/69 kV transformers, CECo leaves out an important 138 kV line owned by Wolverine that operates in parallel to the CECo system and through which power can flow in either direction. MS I.B. at 56, n.9.
>
> For the purpose of determining whether facilities are integrated, it is immaterial who requested interconnections.
>
> In arguing that construction of the MCP Integrated System facilities did not eliminate the need for any new CECo facilities, CECo ignores the benefits that are derived by CECo's power and transmission customers as a result of facilities built by MCCP members.
>
> CECo has not proven that it can supply its own load and that of other CECo transmission customers without reliance upon the MCP Integrated System.
>
> CECo has carefully limited its claim that the Airport Line does not increase its ability to serve load at Alpena during a line outage. The line is necessary to serve load, and if CECo wanted better joint planning, it should have requested it.
>
> Company witness Erickson's studies show that: the MCP Integrated System facilities make a contribution to cross system transactions, redundancy is a component of good transmission planning, and CECo failed to subject its own facilities to similar tests.

MS R.B. at 17-21.

In reply to Edison Sault, MS argues that Edison Sault's system costs should not increase under the enlightened transmission planning, operation and pricing system being facilitated by the Commission in its recent orders; that to follow a different course would be akin to "Balkanization" of systems leading to pancaking of rates, poor planning and functional difficulties. Comparability requires the result it advocates, Michigan Systems contend, even if Edison Sault has to pay higher costs. MS further points out that under its proposals, customers of CECo, like Edison Sault, who themselves own extensive transmission facilities, would be entitled to appropriate credits for their investments. MS R.B. at 13.

Ruling on Credits for Customer-Owned Facilities:

First, it is appropriate to recognize that the Company's transmission rate base needs to be adjusted to comport with the Commission's ruling on its petition in Docket No. EL98-21-000 for a declaratory order, discussed in Issue 1 A above. That fact alone brings the present issues surrounding Michigan Systems' claims for credits into more proper balance.

The Commission's embarkation upon a new transmission policy designed to foster open access and equitable rate treatment of transmission facilities, expressed in its Order Nos. 888, 888-A, 888-B and 888-C, will require some fresh thinking and will necessitate some justified departures from the rules of the past. Notably, it may no longer be sufficient for a company making a claim for rate base inclusion of its transmission system to say, as CECo has here, with Staff's surprising support, that it has appropriately included facilities traditionally rolled into transmission rates by public utilities. Nor will it be availing to rely upon sweeping declarations that the facilities for which rate base treatment is claimed are integrated into plans and operations to serve customers, without demonstrating exactly how that integration occurs, particularly where there is a challenge to the claimed rate base.

Here, the rate base will reflect changes as a result of Docket No. EL98-21-000, and specific rulings on credits below that will result in just and reasonable rates, without the necessity of "unscrambling the egg," as Staff was so loathe to do. However, in other cases it may be necessary to do exactly that -- unscramble the egg -- and to have stronger support for claims of integration in order to achieve the rate setting goals of the statutes the Commission is charged with implementing.

Michigan Systems' claims for credits are based upon Section 30.9 of the OATT, certain Commission policy statements interpreting that tariff language and relevant Commission decisional precedent. The underlying intent of this supporting rationale is that network customers owning transmission facilities that are integrated with the transmission provider's transmission system should receive a credit. While this seems clear, the Commission's definition of the word "integrated" is not as clear as perhaps it should be. Working with what we have, the following elements, derived from the sources cited above, would appear necessary to satisfy a claim for credit based on integration:

> the network customer must demonstrate that the facilities for which it seeks credit are integrated into the plans and operations of the transmission provider to serve its power and transmission customers.
>
> a key requirement of integration is that the transmission provider is able to provide transmission

> service to itself or other transmission customers over the network customer's facilities.
>
> actual use of a network customer's facilities by the transmission provider to provide service to the network customer or other parties.
>
> to be eligible for a credit, the network customer must not only demonstrate that its facilities are integrated into the plans and operations of the transmission provider to serve its power and transmission customers, but must also show that its facilities provide additional benefits to the transmission grid in terms of capability, reliability and are relied upon for coordinated operation of the grid.

The Commission has also provided guidance as to what will not satisfy the integration standard:

> interconnection of a network customer's facilities with those of the transmission provider alone is not enough to prove integration.
>
> the fact that the network customer's facilities serve a transmission function on the customer's side of the interconnection point is not enough to prove integration.
>
> the fact that a network customer's line constitutes a parallel path and is subject to parallel loop flows does not compel a conclusion that the line operates as part of an integrated network.
>
> unnecessary redundancy provided by a network customer's facilities cannot qualify for a credit.

Reviewing these elements against Michigan System's claims for credits, MS fails to demonstrate clearly and convincingly that the facilities for which it seeks credit, with the sole exception of the Airport Line, are integrated into CECo's transmission system in the manner contemplated by the Commission. The record shows an effort by Michigan Systems to convert transmission facilities, for the most part 69 kV or lower, that are essentially interconnected with those of CECo, but perform functions almost exclusively for the benefit of MS, into components of an integrated network, along with those of CECo. That effort, however, does not succeed. MS shows interconnection, redundancy, and some parallel paths and bi-lateral power flows, but does not convincingly demonstrate how its facilities, with the exception of the Airport Line discussed below, provide additional benefits to the grid in terms of capability and reliability. Moreover, it does not show that its facilities are relied upon by CECo for coordinated operation of the grid. CECo in fact denies a need for MCCP facilities to supply its own load and the load of other CECo transmission customers. All ten 138 kV interconnection systems between CECo and the MCP Integrated System were installed at the request of MCCP or its predecessors to receive power from the CECo system and those interconnections did not eliminate the need for new CECo facilities. Ex. CE-73 at 16. The studies of MS witness Reising show some bi-lateral power flows, which the witness concluded evidenced integration; however, the study fails to show persuasively that CECo relied upon those flows to serve its own load or the load of other transmission customers. Id. at 20.

The testimony of Staff's witness Smith provides further support for the conclusion that the MCCP facilities are not, with the exception of the Airport Line, integrated into the plans and operations of CECo to serve all of its power and transmission customers. Ex. S-30. Mr. Smith performed so-called MW-Mile studies on seven cases. In each, he analyzed flows to determine if the interconnection of MCCP facilities with those of CECo demonstrated evidence of integration. In all but one, the Airport-Livingston line, he concluded that the facility examined did not constitute a network facility and, therefore, was ineligible for a credit. MS is critical of the MW-Mile analysis because it contends that even a relatively large flow on the line will appear small when multiplied by the length of the line measured where such lines are not very long. MS I.B. at 45-6. However, the methodology employed by Mr. Smith was not shown to be inappropriate 7/, and the persuasiveness of Mr. Smith's testimony was not seriously challenged. I conclude that it may be relied upon in support of the CECo witness Erickson's similar conclusions, reached primarily via a different route.

The Airport Line, a 61 mile, 138 kV Wolverine transmission line operating between the Livingston substation to the Airport, has been identified by Staff witness Smith as potentially qualifying for a credit because, viewed along with CECo facilities, it forms a network facility. It is interconnected with CECo facilities at both ends and serves a network function. Ex. S-30 at 23. CECo argues that even this small part of the network customer facilities for which credit is claimed is ineligible because it was not planned jointly and provides no benefit to CECo at Livingston or Alpena. Staff has shown, however, that this 138 kV line is comparable to CECo facilities

7/ The Commission has accepted this methodology for cost allocation purposes in a pool-wide transmission arrangement Mid-Continent Area Power Pool, 69 FERC • 61,347 at 62,307 (1994); and for pricing transmission service in a pool-wide open access transmission service. Southwest Power Pool, Inc., 82 FERC • 61,267 at 62,051-52 (1998).

to which it is interconnected, and performs functions similar to those rate-based CECo facilities. MS is correct that it should receive credit for this line.

ISSUE 1 C -- Michigan Grid

Michigan Systems advocate the formation of a "Michigan Grid" that would include the transmission facilities of CECo, the MCCP members' facilities, and those of the Detroit Edison Company. A single transmission system that is coextensive with reasonable sales markets would encourage competitive sales markets, and for the same reason, would enhance electrical coordination and reliability, MS argues. MS I.B. at 89. MS urges the Commission to set transmission rates in recognition of the Michigan peninsular grid that exists and is used by CECo to its benefit. This would be consistent with principles of comparability and open access, Michigan Systems argue. The Commission has the requisite authority, MS contends, to set rates in recognition of the fact that the economic transmission grid includes the facilities of multiple systems. Permian Basin Area Rate Cases, 390 U.S. 397 (1968). The Commission has authority to price on the basis of the entire grid to prevent discrimination, so it can certainly price transmission by considering the cost impacts of systems that participate in forming the grid, MS argues. Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581 (1945). Michigan Systems maintain that such action would be consistent with the broad pro-competitive purposes of the Federal Power Act.

Formation of a "Michigan Grid" would curb CECo's effective operation of a unitary transmission system with Detroit Edison, to the exclusion of the smaller systems, MS contends. CECo refuses to recognize entitlements to credits, and excludes smaller systems' transmission in its definition of a grid for pricing purposes although it benefits from municipal and cooperative investments, but treats Detroit Edison's investment differently, MS argues. This is discrimination that cries out for remediation, according to Michigan Systems. MS I.B. at 92. Using this case to develop a "Michigan Grid" will help remediate this discrimination and fulfil the promise of Order No. 888, claims MS.

CECo contends that this MS proposal is outside the scope of the Commission's Orders setting this proceeding for hearing. Moreover, CECo argues that due process problems abound with the MS proposal, since interested third parties have had no notice that such a proposal might be considered in this proceeding. CECo argues that MS is attempting to transform a proceeding generated solely by a CECo tariff and service agreement filings into a proceeding to consider whether involuntary membership in an independent system operator arrangement should be mandated. Finally, CECo notes that it, along with Detroit Edison, has filed an accepted joint tariff as directed by Order No. 888 for power pools, which is available for parties desiring transmission service in situations where both CECo and Detroit Edison lie in the contract path.

Staff believes that Michigan Systems' attempt to create a "Michigan Grid" is inappropriate in this proceeding. This proceeding considers CECo's open access tariff for its own system. The proceeding was not established by the Commission to consider a proposal such as the one offered here by MS. Staff concludes that it is simply beyond the scope of this proceeding.

Ruling on Michigan Grid:

While Michigan Systems offer some sound arguments in support of the establishment of a "Michigan Grid" or other rational pooling of transmission systems, CECo and Staff are correct that the issue is outside the scope of the matters the Commission set for hearing in this proceeding. Moreover, the Company is also right that consideration of such a proposal here would create serious due process concerns. MS will have to wait for another opportunity to press its policy and discrimination issues. Its proposal for the establishment of a "Michigan Grid" for pricing transmission services is rejected.

ISSUE 1 D -- Voltage-Differentiated Rate Structure

ABATE offers evidence supporting the adoption of separate rates for service at or above 120 kV (bulk transmission) and below 120 kV (subtransmission). Ex. ABATE-1 at 5-9. ABATE argues that voltage-differentiated rates will more accurately track costs and provide more appropriate price signals to users of the transmission system. There is a logical point of separation between CECo's transmission and subtransmission systems based upon voltage levels, ABATE contends. CECo's transmission system includes bulk facilities at 120 kV or above, and subtransmission facilities generally ranging from 23 kV and 69 kV, which are designed to deliver power to the Company's distribution system from the bulk facilities. The subtransmission facilities are not used by all transmission customers, ABATE maintains, and should, therefore, be separately priced. If the revenue requirement was separated between bulk and subtransmission facilities, the subtransmission rate would only be paid by that system's users, which comports with the principle that costs of operating a system should be paid by those who use the system.

ABATE proposes a split of the Company's proposed $110 million revenue requirement where $43.6 million would be assigned to subtransmission and $59.8 million to bulk transmission, after removing $6.6 million for the cost of generator step-up transformers. Exs. ABATE-1 at 7; ABATE-3.

ABATE also points out that the Company's position has evolved to one which embraces voltage-differentiated rates in that it has proposed voltage-differentiated rates in connection with Michigan's Retail Open Access Program. ABATE I.B. at 6.

Staff notes that ABATE's proposal is consistent with the MPSC's actions, discussed above, which determined the jurisdictional split between distribution facilities and transmission facilities. That state agency determined that 46 kV facilities should be classified as distribution. Staff agrees with ABATE and recommends that facilities 120 kV and above be classified as bulk transmission facilities and those facilities at 46 kV and below as subtransmission facilities. Staff I.B. at 10.

Michigan Systems believe that ABATE's proposal has merit, but offers the view that an embedded cost, rolled-in rate may not be appropriate for charging customers connected to CECo's system at lower voltages. MS asserts that it may be more appropriate to develop the rates for customers connected at lower voltages on a direct assignment basis. They suggest that a second phase of this proceeding be established to determine whether low voltage rates should be developed on a rolled-in or direct assignment basis.

CECo's position is that, until the Commission grants its concurrence in Docket No. EL98-21-000 with the MPSC's Order in Case No. U-11283 approving a division between CECo's transmission and local distribution facilities, a single, rolled-in rate is appropriate. The Company contends that the rolling-in of transmission and subtransmission facilities has been approved previously, citing AES Power, Inc., 74 FERC • 61,220 (1996), and Utah Power & Light Co., 14 FERC • 61,162 at 61,296 (1981), among others.

Ruling on Voltage-Differentiated Rate Structure:

As noted above, the event that CECo was awaiting, Commission concurrence with the MPSC's Order, has occurred. The Commission has granted its concurrence with the MPSC's division between local distribution and transmission facilities, of which notice has been taken. Accordingly, ABATE's proposal to set voltage differentiated rates will be adopted. Further, Michigan System's point about the design of subtransmission rates is moot as it regards this Commission, due to the agency's concurrence with the jurisdictional split advocated by the MPSC in Docket No. EL98-21-000.

ISSUE 1 E -- Generator Step-Up Transformers

Generator step-up transformers ("GSUs") are electrical devices that deliver power from lower voltages at the generation level to higher voltages at the transmission level. Ex. S-1 at 7. They are located at or near the generation facilities and are required because the voltage output from the generator is too low for efficient power transmission. Id. Consistent with Commission precedent prior to unbundling and recent decisions of Presiding Judges, CECo has included GSUs in its transmission rate base, and argues that it remains appropriate to do so, citing Minnesota Power & Light Co., 3 FERC • 61,045 (1978) and Niagara Mohawk Power Corp., 42 FERC • 61,143 (1988).

Michigan Systems argue that GSUs are specifically related to the efficient and economic production of power and should not be included in the transmission rate base. MS contends that GSUs aid in the economic generation of power because, without GSUs, the output voltage of the generator would be too low for delivery of power to distant loads requiring that generating plants be located close to loads. Ex. MS-41 at 7; Ex. S-1 at 7. GSUs do not support the transmission function for the benefit of CECo's OATT and are not necessary for the operation of the transmission system, MS asserts. Moreover, according to Michigan Systems, CECo itself has argued, at the state level, that GSU-related costs more properly should be classified as production or generation costs. Ex. ABATE-16 at 7. The MPSC accepted CECo's argument that GSU costs are closely aligned with the generation function. In Re Consumers Power Co., Case No. U-11283 (MPSC Order filed January 14, 1998) at 16. CECo's witness Gaarde, in the instant proceeding, also admitted that many of CECo's GSUs should be reclassified as generation on a functional or operational basis. Tr. at 43, 45-48; Ex. MS-7.

Michigan Systems further contend that the Commission's Order No. 888 supports exclusion of GSU-related costs from the transmission rate base. Arguing that while the cases cited by CECo approve inclusion of GSU-related costs in transmission rates 8/, MS maintains that those decisions predate the Commission's current approach to transmission pricing and its preference, stated in Order No. 888, for unbundled transmission rates. Michigan Systems point out that the Commission itself signaled the possible need for reexamination of the so-called "bright line" historical approach to functionalization of costs between generation and transmission, and labeled GSUs as "the most likely candidates for refunctionalization." AES Power, Inc., 74 FERC • 61,220 at 61,744 (1996), Order on Reh'g, 76 FERC • 61,165 (1996); Northern States Power Co., 64 FERC • 61,324 at 63,379 (1993),

8/ Niagara Mohawk Power Corp., 42 FERC • 61,143 at 61,323 (1988); Minnesota Power & Light Co., 3 FERC • 61,045 (1978).

Order Denying Reh'g and Granting Clarification, 74 FERC • 61,106 (1996).

Michigan Systems additionally argue that, by including GSU costs in transmission rates that are unrelated to a transmission customer's use of CECo's transmission system, it forces many transmission customers to pay for GSU-related costs twice. CECo's customers who desire to connect their own generating units to CECo's transmission lines would be required to install the necessary GSUs at their own expense, as well as to pay for the CECo GSUs in their transmission rates, MS contends. Ex. M-41 at 5. Because this "subsidization" is a one way street -- CECo does not contribute to the customers' GSU-related costs -- it runs afoul of the Commission's comparability standards, Michigan Systems argue.

MS proposes the removal of $75,200,856 from CECo's transmission rate base, which it contends is consistent with CECo's accounting-based calculation of its rate base. If any amount of GSU-related costs is to be removed from its rate base, CECo argues that the calculation should be done on a functional basis. CECo would exclude $45,552,808, less depreciation, on this basis. Staff calculates an amount close to the Company's proposal, $45,585,732.

Staff contends that CECo's position before the MPSC precludes it from arguing that GSUs are properly reflected in transmission rates. Noting that Consumers Energy advocated reclassification of GSUs to generation, and received a favorable state decision on its request, Staff claims that CECo cannot now seek to recover its GSU-related costs in its network and point-to-point transmission rates. Staff states that it is disingenuous of CECo to claim on the state level that its GSUs serve a production-function and at the same time argue before this Commission that such facilities serve a transmission function. Staff I.B. at 13.

Staff further maintains that the unbundling requirements of Order No. 888 preclude the continued rolling of GSU-related costs into unbundled open access transmission rates. Staff admits that the Commission is not there yet and that, historically, GSU's have been rolled in with other transmission facilities for allocation purposes. For its historical context, Staff cites, among other cases, Minnesota Power & Light Co., 3 FERC • 61,045 at 61,137 (1978); Otter Tail Power Co., 12 FERC • 61,169 at 61,421 (1980); and New York State Electric & Gas Corp., 37 FERC • 61,151 at 61,366 (1986). Staff claims that GSU cost allocations were not critically examined in an era when bundled generation and transmission services or full requirements service predominated. With the development of a competitive bulk power supply under open access transmission, the potential for cross-subsidization caused by misclassification of costs has obviously increased, Staff argues. Staff goes on to point out that the Commission, in the Northern States case, observed that refunctionalization of GSU-related costs to production would require the corresponding development of a separately stated reactive power charge. But now, Staff observes, the Commission mandates the use of a similar charge for one of the six ancillary services required under Order No. 888. Staff I.B. at 15. In the new competitive markets fostered by Order No. 888, the development of accurate and timely prices for the component parts of previously bundled services is necessary, Staff argues, for customers to receive the correct price signals so that they may select the best options available to them.

Staff further maintains that a transmission customer that pays for and imports power having an efficient transmission level voltage into a given control area is competitively disadvantaged if it must pay a base transmission rate that includes the separate and redundant (to the customer) GSU-related costs, particularly considering that the purpose of the GSUs is to increase the voltage of the control area operator's own generation. The situation is aggravated, Staff contends, because the native generation effectively receives a subsidy by having a portion of its GSU-related costs borne by the competing imported power provider. This would violate one of the basic tenets of Order No. 888, Staff claims, namely, that the transmission provider take service on the same terms and conditions that it offers to others. Id. at 17, citing Order No. 888 at 31,743, n.452; Order No. 888-A at 30,271, n.277.

Notwithstanding the fact that the Commission has signaled the likely candidacy of GSU-related costs for refunctionalization, and the importance of completing the comparability and unbundling picture so that accurate price signals are set for all aspects of an efficient competitive power market, Staff notes that Presiding Judges have, up to date, declined its request to reconsider GSU treatment. See Florida Power & Light Co., 73 FERC • 63,018 at 65,199 (1995) (pending on exceptions) (where the Presiding Judge found that GSUs are tangential or ancillary to transmission service and both decrease losses and improve the reliability of transmission service); Maine Public Service Co., 74 FERC • 63,011 at 65,018 (1996)(pending on exceptions at the time of the briefs, but since decided) (where the Presiding Judge found that the GSUs could not easily be allocated to specific portions of the system or to specific services in the absence of specific engineering testimony); Kentucky Utilities Co., 75 FERC • 63,024 at 65,091 (1996)(pending on exceptions at the time of briefs, but now decided) (where the Presiding Judge rejected Staff's position without prejudice to its making a detailed showing in a future case of the propriety of classifying GSU costs to production); Northern Indiana Public Service Co., 79 FERC • 63,009 at 65,102-103 (1997)(pending on exceptions) (where the Presiding Judge relied upon earlier Commission precedent and found that Order No. 888 did not change Commission policy); American Electric Power Co., 80 FERC • 63,006 at 65,056 (1997)(pending on exceptions) (where the Presiding Judge acknowledged Staff and intervenor arguments but found that they had not shown that unbundling converted a transmission function into a generation function); and Niagara Mohawk Power Corp., 82 FERC • 63,018 at 65,133-35 (1998)(pending on exceptions) (where the Presiding Judge was sympathetic to Staff's position and would have recommended it, had the slate been clean, but declined to do so because the Commission had spoken on the subject and had the opportunity, with five initial decisions pending, to change its position).

ABATE agrees with Staff and Michigan Systems that GSUs should be classified as generation-related facilities on grounds of cost causation and fairness. Only transmission customers who purchase their power from CECo actually make use of the Company's GSUs, ABATE argues. ABATE contends that CECo realizes a competitive advantage over independent power producers by inclusion of GSU costs in transmission rates, because the independent producers must pay for the cost of their own GSUs. ABATE presses for a $6.6 million reduction in CECo's transmission revenue requirement to reflect the assignment of GSU-related costs to generation instead of transmission.

Ruling on Generator Step-Up Transformers:

This case is different in at least one respect from the pending proceedings where this issue has been raised. Here, there is evidence that the Company argued successfully before the MPSC that GSUs should be classified as generation plant and sought to have the State Commission's determinations adopted by this Commission as well, in Docket No. EL98-21-000. By Letter Order issued July 29, 1998, the Commission declined to adopt the MPSC's reclassification of facilities from transmission to production because the scope of that proceeding was limited to the classification of facilities between transmission and local distribution. 9/ Nevertheless, the Company's admissions in the context of the Michigan proceeding and its request before this Commission for a declaratory order adopting a reclassification of GSUs from transmission to generation cannot be ignored in the setting of transmission rates in the instant proceeding. There is, indeed, some disingenuity on the Company's part in continuing to advocate assignment of its GSU-related costs to the transmission function in this proceeding, while advancing

9/ As noted, the Commission adopted the MPSC's findings that certain facilities identified in the pleadings are State-jurisdictional local distribution facilities and others, identified there, are Commission-jurisdictional transmission facilities.

contrary positions in the Michigan state proceeding and in Docket No. EL98-21-000.

Of course, the Company's position regarding the proper classification of GSUs in the state proceeding and the MPSC's determination, which has not been adopted by this Commission, are not fully dispositive of the matter before us. Here, Staff and MS have urged that the GSU classification issue be reexamined in light of Order No. 888's requirements for comparability and mandatory unbundling of production, transmission and ancillary services. What Staff, MS and ABATE argue is that the Commission's Order No. 888 provides a valid opportunity for reexaming this issue because the Commission, in that Order, changed the construct of its earlier decisions, which were made when generation and transmission services were bundled and where the classification issue regarding GSUs was not of critical significance. This argument is convincing on this record and in the circumstances of this proceeding. Placing the issue of proper classification of GSU-related costs in the current regime of unbundled services designed to facilitate bulk power supply competition through open access transmission service, it is quite clear that GSU-related costs must be removed from transmission rate base. To do otherwise would impede in two ways the Order No. 888's goal of allowing non-traditional generators to access the transmission grid on a non-discriminatory basis: first, by charging transmission users rates that include costs for services not required by the transmission customer, and, second, by subsidizing the transmission owner's generation by inclusion of its GSU costs in transmission rates paid by competitors.

The rate treatment advocated by CECo would violate one of the basic principles of Order No. 888, i.e., that the transmission provider take services on the same terms and conditions it offers to others. The violation occurs because, under the existing scheme, the transmission provider's GSU transformer costs are recovered in its transmission rates, which is a subsidy unavailable to competitive generators who must pay their own GSU transformer costs.

While the case for the position advocated by MS, Staff and ABATE is strong enough to prevail as argued on this record, it is important to note that the Commission's recent decisions in Kentucky Utilities Co., 85 FERC • 61,274 (November 25, 1998) and Maine Public Service Co., 85 FERC • 61,412 (December 22, 1998), remove all doubt as to the proper outcome. In Kentucky Utilities Co., the Commission reexamined its previous policy on the functionalization and recovery of costs associated with GSUs to ensure that customers of unbundled services pay only their appropriate share of the cost of services that they use. Noting that much had changed since it decided the line of cases where the costs of GSUs were included in basic transmission rates, the Commission, largely for the reasons offered here by Staff, MS, and ABATE, concluded that the costs of a GSU transformer should be directly assigned to its related generating unit. Because GSUs are used in the provision of both generation and ancillary services, the Commission found that the costs of these facilities should be charged to customers using those services, and not to customers of transmission service. The decision in Maine Public Service Co. is in accord. Accordingly, I conclude that GSU transformer costs should be removed from the transmission rate base. 10/

The amount that should be deleted from transmission rate base is also contested. CECo believes the reduction should be no more than $30,197,719, after deducting depreciation reserves. Its witness Gaarde calculated this figure based upon an operational or functional analysis of recent GSU data. Ex. CE-55 at 2-3. ABATE argues for a revenue requirement deduction of $6.6 million for this purpose. Ex. ABATE-1 at 3-5,7. Staff's number is close to the Company's, namely $46,552,808, less $16,000,000 depreciation reserve, or $30,552,808. Ex. S-1 at 10. Michigan Systems would remove $75,200,856, less $27,915,688 in depreciation reserves, or $47,285,168. MS bases its proposal on an historical accounting basis, removing the entire original investment in GSUs.

Because the Company's transmission rate base is based upon historical original costs, items should be removed from rate base using the same methodology. It would be mixing apples and oranges to remove items from rate base using a functional or operational analysis when the rate base itself was calculated on an historical accounting basis. MS' position is more persuasive and is thus adopted.

ISSUE 1 F -- Dedicated Line and Substation Investment

Michigan Systems argue that CECo has included in its proposed transmission rate base facilities that generally play no role in serving the transmission needs of customers like MS. These include radial lines and substations dedicated to specific customers. According to MS, these lines are not used to provide service under the OATT. Ex. MS-41 at 8-9. MS therefore proposes to remove $21,851,694 worth of original plant investment, less $6,704,399 in depreciation. Id. at 9; see also Ex. MS-45.

CECo refers to what it describes as the Commission's long-held preference for rolled-in pricing in support of inclusion of radial lines in its transmission rate base, citing Detroit Edison Co., 54 FPC 3012 at 3020 (1975); Public Service Co. of Indiana,

10/ CECo should be allowed to revise its ancillary service rates to include appropriate GSU transformer costs in the derivation of those rates.

56 FPC 3003 at 3034-36 (1976); and AES Power, Inc., 74 FERC • 61,220 at 61,744 (1996). CECo contends that it is a basic truism that most transmission customers on an integrated system do not generally use all of the features of each system that are important to the reliability of the service. Niagara Mohawk Power Corp., 42 FERC • 61,143 at 61,530 (1988). That certain customers might not use some parts of an integrated system is not a valid reason to depart from rolled-in pricing, CECo argues.

Ruling on Dedicated Line and Substation Investment:

The dedicated lines and substation investment should not be included in the transmission rate base for the same reasons that govern the ruling on Voltage-Differentiated Rates. These facilities will be included in the subtransmission category, per the Commission's adoption of the Company's proposal in Docket No. EL98-21-000.

ISSUE 2 A -- Rate of Return

To begin, there is no disagreement among the parties on the following elements of the rate of return calculation: the appropriate capital structure, cost of long-term debt or the cost of preferred stock. The agreed-upon elements are:

Element	Amount (000)	Ratio	Cost
Long Term Debt	$2,034,171	49.09 %	7.29 %
Prefer'd Stock	$ 354,726	8.56 %	7.80 %
Common Equity	$1,755,074	42.35 %	-
TOTAL	$4,143,971	100.00 %	-

However, CECo and Staff disagree upon what the authorized return on common equity should be. The Company presented the testimony of Mr. Ernst, its Director of Rates, in support of its requested authorized return on common equity of 12.25 percent. Exs. CE-25 at 41-61; CE-59 at 22-28; CE-112.

CECo, a wholly owned subsidiary of CMS Energy Company, does not have publicly traded common stock. Accordingly, Mr. Ernst first selected a group of proxy companies, which he determined were comparable, as a group, to CECo's operations. Ex. CE-25 at 44. Mr. Ernst used the Discounted Cash Flow ("DCF") methodology in developing his recommended return on equity. He used the

Capital Asset Pricing Model ("CAPM") as a check upon the reasonableness of the results obtained via the DCF approach.

Mr. Ernst testified that two principal factors affect the risks perceived by investors: business risk, which encompasses all of the risks of a firm as if it were financed entirely by common equity, and financial risk, which is the risk added by issuance of debt and preferred stock. Mr. Ernst testified that business risk was increasing for electric utilities in general, and for CECo in particular. Ex. CE-59 at 27-28; Tr. at 708. He found that a return of 12.25 percent would fairly and reasonably compensate investors for the overall risk incurred by an investment in CECo, assure confidence in the financial integrity of the Company, and allow the Company to maintain and support its credit and attract capital, thereby satisfying the standards of Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia, 262 U.S. 679 (1923), that equity investors are entitled to earnings commensurate with other investments of comparable risk, and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944), that a return should be set at an appropriate level such that a utility can maintain and support its credit and attract capital.

Staff presented the testimony of its expert, Mr. Green, who, like CECo's witness Mr. Ernst, used the DCF method that has been long approved by the Commission. Staff's witness, however, employed a different proxy group than Mr. Ernst and different inputs into the DCF formula to reach a recommended return on equity of 9.4 percent. Exs. S-38; S-25.

Michigan Systems argue that the return requested by CECo is too high because it reflects risks of an electric company engaged in activities in addition to the provision of electric transmission service. MS contends that it would be appropriate to set the Company's return as if it were a stand-alone transmission company, given the Commission's encouragement of unbundling and electric industry restructuring in its Order No. 888. It argues that the rate of return for CECo's transmission service should reflect the lower risks associated with the provision of monopoly transmission service. MS I.B. at 106, citing Northwest Pipeline Corp., 79 FERC • 61,309 at 62,381 (1997). Further, MS critiques CECo's DCF analysis, for much the same reasons advanced by Staff. 11/

The differences between the approaches of the Company and Staff's witnesses lie in three areas: (1) the appropriate proxy or comparable group to use in determining the return on equity

11/ Michigan Systems' arguments on DCF issues mainly agree with Staff's. Accordingly, while these arguments have been considered, they are not separately discussed herein.

for CECo; (2) the appropriate growth rates to be used in the DCF formula; and (3) the appropriate dividend yields to use in the DCF formula.

1. Proxy Group

In selecting proxy companies, CECo's witness focused attention on electric companies whose business was primarily electric operations. The criteria employed were historical information on (1) bond ratings; (2) equity ratio; (3) net plant size; and (4) geographic location. Ex. CE-25 at 45.

For bond ratings, which measure a utility's default risk, Mr. Ernst selected a range of A1/A+ to Baa2/BBB. At the time of his testimony, CECo's bond rating was Baa3/BBB+. Ex. CE-112 at 9. As for equity ratio, Mr. Ernst used Regulatory Research Associates' "Industry Study, July 1, 1997, Electric Utility Quality Measures" (Ex. CE-90) to develop a range for this selection criterion of between 36 percent and 46 percent, which is a plus or minus 5 percent range around CECo's 41 percent equity ratio. For plant size, Mr. Ernst selected companies with net plant between $1 billion and $8 billion. CECo has a net plant investment of $4.5 billion. He also limited the geographic location to utilities in the Midwest and Mid-Atlantic areas to find utilities operating under comparable meteorological conditions.

Mr. Ernst selected the following proxy group of five companies to perform his analysis:

Atlantic Energy, Inc.
Delmarva Power & Light Company
Illinova Corporation
Minnesota Power & Light Company, and
PP&L Resources, Inc.

Ex. CE-54 at 15.

Staff's witness was critical of the inclusion of companies (Atlantic Energy and Delmarva Power & Light) with a merger in progress. Also, Staff condemns the Company for failing to include in the proxy group CECo's parent, CMS Energy, since CECo accounts for most of CMS Energy's revenues. Staff further argues that geographic considerations have not been justified as a selection criteria.

Staff's witness Green used CMS Energy as a proxy for CECo and determined his proxy group by looking at companies comparable to CMS Energy. The three companies selected by Mr. Green were Illinova Corporation, Rochester Gas and Electric and Eastern Utilities Associates. His criteria for selection included similar bond ratings, similar safety ratings from Value Line

Investment Survey, similar operational risks and similar operational safety and cost risks. Finally, he excluded companies with merger activity within the six months of data that he employed. Exs. S-25 at 8-10; S-26 at Schedule 5; Tr. at 1792.

CECo contends that Staff's focus on companies that were comparable to CMS Energy is misplaced in that it does not give proper emphasis to the electric business. The goal, according to CECo, should be to select a group of companies comparable to the jurisdictional company whose rates are being set by the Commission. Because the proxy group selected by Staff's witness Green is heavily influenced by combination gas and electric companies, insufficient emphasis is placed on electric operations, CECo maintains.

The Company also argues that Staff's proxy group is too small, consisting as it does of only three companies. CECo also argues that Staff's witness, in testimony in another case, Docket No. SC97-2-000 involving El Paso Electric Company, used a selection criterion that gave greater weight to companies with a high percentage of revenues from electric operations than he did in this case. Exs. CE-107; CE-108; CE-109. Mr. Green also inappropriately excluded Entergy Corporation ("Entergy") from his proxy group, CECo argues, because its percentage of electric revenues to total revenues is 90.05 percent, just outside his established bounds of 30 to 90 percent, while he includes Eastern Utilities Associates, whose ratio is 89.3 percent. Inclusion of Entergy would raise the return recommendation, claims CECo.

CECo further contends that the Staff witness' proxy group is not comparable to CMS Energy in terms of internal growth rate, retention rate and earned return on equity, so that the group could not provide a meaningful indication of investor expectations of CMS Energy. Ex. CE-60. Moreover, CECo maintains, two of Mr. Green's three companies are not comparable to CECo and should have been excluded. Rochester Gas & Electric does not meet the equity ratio criterion determined as appropriate for comparative purposes by CECo's Mr. Ernst, and Eastern Utilities Associates fails to meet the CECo witness' net plant size and geographic criteria. Staff also failed to use equity ratio as a selection criterion, which CECo contends results in inadequate attention to financial risk as a selection factor.

CECo also sees as inapt the comparison of Rochester Gas and Electric with CMS Energy, claiming that the latter has high expected growth, whereas the former is perceived by investors as having low growth potential. Moreover, the Staff witness' exclusion of companies involved with mergers was inappropriate, says CECo, because the markets can be expected to self-correct stock prices for merger participants, returning to normal levels within 60 days of a merger announcement. Tr. at 569-71.

Finally, CECo argues that Staff should not have used CMS Energy as a proxy for CECo because, even though 87 percent of CMS Energy's revenues derive from CECo, the Company's electric operations account for only 56 percent of its revenues. It is therefore inappropriate, the Company contends, to view CMS Energy as a proxy for CECo's electric business.

Ruling on Proxy Group:

The Company has the better proxy group. Staff's use of CMS Energy as a proxy may seem intuitively right. However, if one is attempting to set a return for CECo's electric operations, as we are here, inclusion of CMS Energy as a proxy carries the baggage of that holding company's other operations, and, as argued by CECo, includes CECo's significant non-electric business, as well. Staff is then left with a three company proxy group, including one combination company, Rochester Gas & Electric, with significant non-electric revenues and with an equity ratio unlike CECo's, and another, Eastern Utilities Associates, whose plant is about one-fifth the size of CECo, and which operates in New England, where climate and meteorological conditions are different from the Midwest where CECo operates. 12/ Nor has Staff offered convincing criticisms of the Company's proxy group proposal. Contrary to Staff's argument otherwise, it has been shown that equity ratio is an important selection criterion. Ex. CE-25 at 43. Moreover, inclusion of merger partners in CECo's proxy group is not fatal for the reasons suggested by CECo. CECo R.B. at 39-40. For the above reasons, the proxy group proposal of CECo will be used for further analysis.

2. Growth rates in the DCF formula

The Commission has expressed a preference for use of a two-stage model for determining growth rates in gas pipeline cases. In the two-stage approach the Commission has used in recent cases, growth rate projections for a five-year period were averaged with longer term growth rate projections. Northwest Pipeline Corp., 79 FERC • 61,309(1997); Williston Basin Interstate Pipeline Co., 79 FERC • 61,311 (1997). Most recently (at the time of this decision), the Commission has revised the equal weighting used in the averaging of short and long term growth rates in those cases and now prefers to give two-thirds weight to the short term growth rate and one-third weight to the longer term growth rate. Transcontinental Gas Pipe Line Corp., 84 FERC • 61,084, Docket Nos. RP95-197-032 and RP96-44-008 (Phase I) and Docket Nos. RP95-197-031 and RP97-197-024, and RP96-44-

12/ Staff's third proxy company, Illinova Corporation, is among the five in CECo's proxy group.

007, Order on Reh'g (July 29, 1998); Williams Natural Gas Co., 84 FERC • 61,080, Docket No. RP93-109-012, Order Granting Reh'g in Part (July 29, 1998). This revision in its two-stage model was made to reflect the greater reliability of the short term projections, while continuing to give some weight to long term growth projections, which the Commission continues to believe warrant recognition. The Commission, however, has not established a preferred approach for electric utility cases.

CECo's witness Ernst calculated growth rates for his proxy companies using a traditional approach and a two-stage approach. In calculating the growth rates using a traditional approach, Mr. Ernst reviewed investment analysts' calculations of growth rates, equally weighting the growth projections of Value Line Investment Survey ("Value Line") and Institutional Brokers Estimate System ("IBES") in order to normalize growth expectations. Ex. CE-25 at 52. The resulting calculation of the average growth rate for the proxy companies is 4.36 percent. Ex. CE-54 at 4.

Mr. Ernst's two-stage growth rate averaged the results of his traditional analysis for the short term growth rate and, for the long term rate, the simple average of the Wharton Economic Forecasting Associates ("WEFA") forecast of the Gross Domestic Product ("GDP") for the years 2003-2015 under the low growth scenario. Ex. CE-25 at 53. This resulted in an average growth rate for the proxy companies of 4.42 percent. However, the Company has accepted Staff witness Green's updated average GDP growth rate of 4.97 percent projected by the Energy Information Administration ("EIA"), DRI/McGraw Hill and WEFA for the period beginning 2002. Ex. S-40 at 22; CECo I.B. at 39-40. Averaging this long term rate with its short term rate resulted in a two-stage growth rate of 4.67 percent. Inclusion of this updated, higher growth rate in its return calculation increased the cost of equity above the number in the Company's return exhibit from 12.27 to 12.53 percent and the midpoint from 12.23 percent to 12.48 percent. CECo I.B. at 39. This, the Company argues, provides further support for its 12.25 percent return request.

Staff's witness Green claimed to have followed the same methodology that the Commission employed in Northwest, 79 FERC at 62,384 and Williston Basin, 79 FERC at 62,390. He combined a five-year growth rate published by IBES with a long term growth rate to arrive at a single growth rate. However, instead of using the GDP forecast for the long term rate as the Commission did in the cited cases, he used DRI data showing the electric industry's return on capital. He believes this approach better reflects the expectations of investors for the future growth in earnings for the electric industry. Ex. S-25 at 12-19. Mr. Green explained that the long term GDP forecast of 5.06 percent

13/ is inappropriate for electric companies, which, according to Value Line, are expected to provide returns in the range of 2.66 to 3.81 percent over the 1997-2001 time frame. Id. at 15. According to Mr. Green, there is no evidence that the electric industry growth rate will increase 125 basis points between 2001 and 2002 and sustain that level through 2020. Accordingly, he used the DRI long term forecast of return on capital for the electric industry, adjusted for company-specific information on the estimated increase in the number of shares, to obtain an estimate of growth in earnings per share. Id. at 18. Averaging the short term IBES growth rate for CMS Energy with the long term share-adjusted DRI growth in return on capital resulted in a recommended growth rate of 5.9 percent for CMS Energy. This, combined with the high and low dividend yields, resulted in a range of recommended returns for CMS Energy of 9.14 to 9.87 percent. The same model applied to the Staff proxy group produced a range of returns of 9.55 to 11.52 percent in Mr. Green's original testimony and 8.79 to 10.77 percent in his updated testimony. Exs. S-26 at Schedule 24; S-39 at Schedule 18. Averaging the results for CMS Energy and the proxy group resulted in a range between 9.35 and 10.69 percent. Mr. Green's recommendation is for a return on equity of 9.4 percent, the rounded mid-point of this range. Staff I.B. at 39.

Staff is critical of Mr. Ernst's growth rate in several respects. First, Staff argues that Mr. Ernst, by averaging a traditional DCF growth rate analysis that used only short term data with a two-stage analysis of short and long term data, gives insufficient weight to the long term projection. Staff contends that this is inconsistent with the Commission's two-stage approach as applied in Northwest and Williston Basin. Second, Staff points out that Mr. Ernst did not use only IBES data for his short term forecast, averaging IBES and Value Line data instead. Because Value Line uses historical data, Staff argues that its use is inconsistent with the Commission's preference for forward-looking growth rates. Staff maintains that the Company could have used Zacks, another forward-looking projection source, if it wished to average two sources for this component of the return formula. Staff R.B. at 17. Third, Staff contends that Mr. Ernst further departed from Commission precedent when he used a twelve-year WEFA GDP forecast, instead of the 20 years used by the Commission. Fourth, Staff maintains that, by accepting Staff's updated GDP growth rate, CECo is cherry-picking a high, updated GDP growth rate and combining it inappropriately with stale dividend yield numbers.

13/ Obtained by averaging estimates of growth in GDP provided by DRI, EIA and WEFA, as the Commission preferred in Northwest and Williston Basin.

CECo, meanwhile, also criticizes Mr. Green's growth rate calculation methodology as inconsistent with Commission precedent in that it does not employ a GDP forecast to derive a long term growth component for the two-stage analysis. CECo argues that Staff's recommended DRI return on capital rate is not an appropriate measure of long term growth expectations because investors do not use the DRI forecast for this purpose and because the GDP more closely matches expected growth in earnings. Ex. CE-59 at 9; Tr. at 703. Further, CECo argues, the DRI return on capital projections does not reflect investor expectations of growth in either dividends or earnings and cannot properly be used as a surrogate for growth in earnings. Ex. CE-59 at 9; Tr. at 658, 1753-4. CECo also points out that the return on capital rate included debt, which is not appropriate to an analysis of growth, and contains an inappropriate assumption of negative growth. CECo R.B. at 54-58.

Ruling on Growth Rate:

Both Staff and CECo have demonstrated the dangers inherent in a departure from soundly reasoned precedent in an attempt to find greater precision. Abandonment of the compass provided by Commission precedent in a search for greater precision often results in journeys through unchartered territory that lead away from one's objective. CECo is correct that Staff's use of the DRI return on capital projections is an unwise departure from the GDP forecast preferred by the Commission for the long term growth component of the two-stage return analysis. While Staff was searching for a forecast that it deemed more appropriate for the electric industry than the GDP forecast used principally in the context of gas pipelines, it ignores other evidence in the case which suggests that an electric company that offers, among other things, unbundled open access electric transmission and related services and a gas pipeline company that offers unbundled gas transmission and related services have much in common.

In the restructuring of the unbundled electric industry encouraged by the Commission's Order No. 888, the electric business of the future will not look very much like the electric industry of the past, making projections of returns on capital predicated on historical assumptions an unlikely source for a true measure of expected long term growth. The record does not explore the return implications of a new industry structure in any depth, beyond Michigan Systems' argument that the return should be set as if the Company was a transmission only entity. There is much to commend the position of Michigan Systems. Unfortunately, its argument was not developed sufficiently on this record to allow for more than an encouragement that its theory be pursued in subsequent proceedings.

In these circumstances, the wisest course is to follow precedent where such precedent has not been shown to be clearly inapposite. The Commission has expressed a preference for use of GDP projections to measure long term growth for gas pipelines. Such pipelines have much in common with an electric company offering open access transmission service, the rates for which this proceeding has been set to establish. Accordingly, the GDP projections of DRI/McGraw Hill, WEFA and EIA will be used for the long term growth component of a two-stage growth rate calculation. The updated growth rate offered by Staff on this basis is 4.97 percent, a value which the Company accepts.

There is also no good reason to depart from the Commission's preference in selecting an appropriate short term growth rate component. The Commission has preferred use of the short term (5-year) growth rate published by IBES. Staff is correct that there is no reason to add Value Line projections, as CECo's witness did, where the IBES data has Commission acceptance and has not been shown to be inappropriate in this case.

Accordingly, the short term growth rate for the proxy companies will be set using only the IBES data, as recommended by Staff. To be consistent with the use of an updated value for the GDP long term component, more recent IBES figures offered by Staff will be employed. Ex. S-56, Column entitled: "Current IBES 5 Year EPS Growth Estimate" (2/19/98).

3. Dividend Yield

The current dividend yield for the CECo proxy group of companies was calculated by determining the closing stock price for each day over six months and calculating an average closing price over the six months. The quarterly dividend used to complete the calculation was the latest recorded dividend from the Value Line Survey at the time of the study. Ex. CE-25 at 49-50. This quarterly amount was annualized by multiplying by four. Monthly yield calculations were then performed for each company by dividing the annualized dividend by the average stock price for each month. The dividend yields, adjusted to reflect that dividends are paid quarterly, are depicted in Exhibit CE-54 at 2.

Staff, however, has demonstrated that the dividend yields computed by the Company and depicted in Exhibit CE-54 may be unrepresentative of more recent trends. Tr. at 598-608; see Exs. S-48; S-49; S-50. In these circumstances, and to be consistent with the updating of the GDP and IBES data employed in the two-stage growth rate determination, more current yield figures than are contained in Exhibit C-54 should be analyzed in determining the appropriate dividend yield for the Company's proxy group to be used in computing the DCF formula. Staff's Exhibit S-48 provides yields for the month ending September, 1997, and Exhibit S-58 shows dividend yields for the Company's proxy group companies in a report dated December 12, 1997. Both of these more current sources depict dividend yields generally below the

March, 1997 to August, 1997 average yield figures calculated by Mr. Ernst at the time of his testimony. Mr. Ernst's approach to the computation is sound, and, if more current figures were available, it would be sufficient. However, it would be wrong to ignore the more recent trend, particularly where other related components of the DCF calculation have been updated. Therefore, the following data will be employed to arrive at the appropriate dividend yield for the proxy group companies to be used in calculating the DCF return:

Company	Yield in Ex. CE-54	Yield in Ex. S-48	Yield in Ex. S-58
Atlantic Engy.	9.20 %	8.59 %	7.7 %
Delmarva	8.58 %	8.16 %	7.3 %
Illinova	5.55 %	5.77 %	4.6 %
Minn. Power	6.87 %	5.64 %	4.6 %
PP&L Resources	8.24 %	7.63 %	7.3 %

Ruling on Dividend Yield:

In order to obtain dividend yields that reflect more current conditions than those offered by Mr. Ernst at the beginning of this proceeding, composite dividend yield figures will be developed by averaging all three dividend yield sources in the record. The results are as follows:

Atlantic Energy, Inc......................8.50 %
Delmarva Power Company.....................8.01 %
Illinova Corporation.......................5.31 %

Minnesota Power & Light Company............5.70 %
PP&L Resources, Inc.......................7.72 %

4. Calculation of the Return on Equity

As noted above, Mr. Ernst averaged the results of a traditional growth approach with those of a two-stage growth approach as a means of giving greater weight to short term growth forecasts, which he concluded investors tend to do. The Commission itself concluded that greater weight should be given to short term growth forecasts in its two-stage model in its Orders on Rehearing in Transcontinental and Williams, to give recognition to the greater reliability of short term forecasts. The Commission, however, simply weighted the short term growth forecast by two-thirds and the long term growth forecast by one-third to achieve what it considered a proper balance.

CECo also prefers use of an average to calculate where within the range of reasonableness the actual allowed return on equity should lie. CECo observes that the Commission in the recent gas pipeline cases has indicated that it will choose a return from the lowest, the midpoint or the highest of the returns calculated in the proxy group, depending upon its assessment of the pipeline's risk or other special circumstances. The Company further notes that no policy has been established for jurisdictional electric companies. Use of an average is argued to be more representative for an electric company said to be of average risk. CECo I.B. at 41-2.

The Company argues that its recommended return of 12.25 percent is conservative because CECo has greater financial risk than the proxy companies as indicated by its lower equity ratio. If this risk factor had been considered and the high end of the range of reasonableness had been deemed appropriate to recognize this risk, CECo contends that a return of 13.0 percent would have resulted. Id. at 44.

Finally, while the Company's return witness, Mr. Ernst, also offered a Capital Asset Pricing Model ("CAPM") analysis, he did not base his recommendation on that approach, but used it to test the reasonableness of his primary 12.25 percent return on equity recommendation. The CAPM approach resulted in a calculation of a required return ranging from 11.75 to 13.20 percent, with an average of 12.12 percent and a midpoint of 12.48 percent. Ex. CE-54 at 12. Mr. Ernst saw the CAPM model as a reasonable method to check the reasonableness of any DCF analysis. Ex. CE-59 at 23.

Staff concludes that a DCF analysis consistent with the Commission's requirements in Northwest and Williston Basin, adjusted to include a growth rate specific to the electric industry and the most current dividend yields, and employing its recommended proxy group, is the correct approach to be followed here. Staff's witness Green testified that the use of the CAPM approach is not appropriate to determine a rate of return. He questioned both the model itself and the components that CECo's witness Ernst entered into the model, contending that the risk-free rate Mr. Ernst used was not in fact risk free, that Mr. Ernst's use of betas, which measure the market risk of a security, was improper, and that the witness' use of a 71-year historical analysis of stock returns to determine the risk premium was inappropriate.

Ruling on Calculation of the Return on Equity:

The proper approach to determine a rate of return on common equity in this instance is a DCF analysis consistent with the

Commission's policy determinations in Northwest and Williston Basin, as modified and clarified in the Commission's Orders on Rehearing in Transcontinental and Williams. While both Staff and CECo claim to have followed the most recent Commission determinations on rate of return at the time of their testimony here, both made departures from the Commission's methodology that have not been well supported, for the reasons discussed. The two-stage growth rate methodology and the weighting suggested in the Commission's most recent return pronouncements is preferable to the weighting suggested by either the Company or Staff. The Commission's two-stage methodology is a cleaner approach than the one suggested by CECo in that it does not introduce a wholly new forecast, such as the one CECo advances here as a "traditional" growth calculation. In addition, providing greater emphasis on short term projections because of their reliability, as the Commission did in the Rehearing Orders in Transcontinental and Williams, is preferable to the equal weighting proposed by Staff. 14/

The approach that will be adopted here to determine the appropriate return on equity is the DCF methodology, employing a two-stage growth rate determination, weighting by two-thirds the more current IBES short term growth projection and by one-third the GDP long term forecast, the latter measured by averaging the EIA, WEFA and DRI/McGraw Hill projections as updated by Staff. The proxy group will be the one proposed by Mr. Ernst, CECo's witness, for the reasons discussed above. The composite, unadjusted dividend yields as determined above will be employed and adjusted for dividend growth.

The results are as follows:

Company	Long Term Growth 15/	Sht. Term Growth 16/	Weighted Growth 17/	Adjusted Yield 18/	Cost Rate 19/

14/ Staff, of course, did not have the benefit of the Commission's decisions in Transcontinental and Williams when it offered its testimony here.

15/ Per Ex. S-40 at 22.

16/ Per Ex. S-56 at Column 4.

17/ Average of Short Term Growth x 2 and Long Term Growth.

18/ [(Weighted Growth x .5) +1] x Composite Dividend Yield.

19/ Adjusted Yield + Weighted Growth.

Atlantic Energy	4.97 %	2.0 %	2.99 %	8.63 %	11.62 %
Delmarva Power	4.97 %	3.5 %	3.99 %	8.17 %	12.16 %
Illinova Corp.	4.97 %	5.1 %	5.06 %	5.44 %	10.50 %
Minnesota Power	4.97 %	4.37 %	4.57 %	5.83 %	10.40 %
PP&L Resources	4.97 %	2.31 %	3.20 %	7.84 %	11.04 %

In conclusion, a return on equity in the range of 10.40 to 12.16 percent has been justified on this record. The return within that range most appropriate for CECo is 11.04 percent, the median of the range of reasonableness, because no special circumstances have been demonstrated on this record that would justify selection of the low or high end of the indicated range. Transcontinental Gas Pipe Line Corp., 84 FERC • 61,084, Order on Reh'g (July 29, 1998).

ISSUE 2 B -- Materials and Supplies and Prepayment Components of Working Capital

Michigan Systems claim that CECo has overstated the Working Capital allowance for Materials and Supplies ("M&S") and Prepayments. The amount claimed by CECo is $10,265,242. MS believes this element should be no greater than $2,300,000.

1. Materials and Supplies

MS argues that CECo has failed to justify the over $9.3 million of transmission related materials and supplies in working capital. CECo developed the M&S component by applying a gross plant allocation to transmission of 14.0346 percent to M&S amounts related to total electric operations. An MS witness noted that CECo's FERC Form 1 includes only $772,157 for transmission related M&S. CECo further claims that the other components of M&S, construction, production plant, distribution plant and "other," were not shown to bear a relationship to transmission. MS also contends that the evidence strongly suggests that the CECo claimed M&S amount includes sums related to construction that are well in excess of an amount that would be replaced to maintain the inventories for normal maintenance, which MS contends is the prevailing standard. Missouri Utilities

Co., 6 FERC • 63,041 at 65,234 (1979), aff'd, 10 FERC • 61,297 (1980), reh'g denied, 11 FERC 61,203 (1980).

CECo responds to the latter MS argument by noting its duty, under an MPSC Order dated March 14, 1980 in Case U-5281, to charge materials used for significant construction projects directly to the job. Accordingly, CECo maintains, these amounts do not go through the Materials and Supplies account. As to the FERC Form 1 argument, CECo's witness Gaarde testified that he applied the customary methodology to determine M&S amounts, by applying the ratio of transmission gross plant to total gross plant, which is 14.0346 percent, to the thirteen month average balances of electric M&S. Mr. Gaarde further testified that the MS witness erred in selecting only the amount labeled "Transmission Plant" on the FERC Form 1, whereas a portion of the "Construction" amounts are properly includable in transmission related M&S. Ex. CE-55 at 5-7. Accordingly, CECo contends that MS seriously understated the amount of M&S to be included in working capital.

Staff agrees with CECo's position that the FERC Form 1 is not the best source for determining transmission related M&S.

2. Prepayments

CECo applies the gross plant allocation factor for transmission, 14.0346 percent to determine the amount of prepayments to be included in transmission related working capital. MS argues that some items in the prepayment base, such as nuclear property insurance, nuclear liability insurance and government nuclear costs, are clearly unrelated to transmission and should have been deleted from the base amount before the allocation was made. CECo responds that the allocation procedure provides a suitable substitute for the more painstaking item by item approach. The Company observes that some base items will be 100 percent inapplicable to transmission, while others will be 100 percent applicable to transmission. The use of an allocation factor should balance out the inequities. Tr. at 64-5. It would, according to CECo, be unfair to delete only the items that are not transmission related before applying the allocator, because this would skew the result in favor of the transmission customer, who would then pay only 14 percent of some items that are 100 percent allocable to transmission.

Ruling on Materials and Supplies and Prepayments:

The Company has relied upon the traditional and customary means of determining the M&S and Prepayment components of working capital. While the gross plant allocation factor may not achieve perfection in determining the precise amounts of M&S and prepayments allocable to transmission, it is a time-tested and reasonable approach. Pacific Gas & Electric Co., 16 FERC • 63,004 at 65,015 (1981), aff'd., 20 FERC • 61,340 (1982).

The challenges by Michigan Systems fail to demonstrate that use of the gross plant allocator here would be inappropriate either for M&S or Prepayments. CECo's witness persuasively showed that use of the FERC Form 1 would be an unacceptable substitute for the gross plant allocation method to determine transmission related M&S because it does not clearly show each element of M&S that is related to transmission. Ex. C-55 at 5-7. As for Prepayments, the choices are to conduct an item-by-item review of the components in the base Prepayment amount to ferret out those Prepayments related to transmission, or to use an appropriate allocation factor. CECo employs the latter technique, which is acceptable given the onerous nature of the alternative. The approach advocated by MS, namely to first delete all non-transmission related items and then apply the allocator, would bias the results by giving inadequate recognition to items in the Prepayment base that are wholly related to transmission. The Company's claimed amounts will be accepted for the M&S and Prepayment components of Working Capital.

ISSUE 2 C -- General Advertising Expense

Michigan Systems and Staff argue that the $31,600 of CECo's general advertising expenses included in the transmission cost of service should not be allowed because the Company has failed to show that the advertising is in any way related to transmission service. CECo defends inclusion of this amount in the transmission cost of service, arguing that the advertising costs allocated to transmission are related to community activities and are not for the purpose of attracting or retaining customers. Tr. at 1591; Ex. CE-58.

Ruling on General Advertising Expense:

The expenses at issue here are directed toward communications with constituencies and informational activities that are normal business expenses for an enterprise of this nature. See Ex. CE-58. There does not appear to be anything nefarious about the Company's advertising goals. Nor can the sum claimed be seen as an undue burden. CECo will be allowed to include in its transmission cost of service the modest portion of its corporate advertising budget claimed here.

ISSUE 2 D -- Taxes Other Than Income Taxes

Michigan Systems seek to disallow the $144,982 allocated to transmission service of the $2,835,451 total assessment paid by CECo to the MPSC. CECo explains that this fee is a levy assessed against every utility doing business in Michigan. MS argues that the fee is collected to defray the state of Michigan's regulatory costs, which are not applicable to transmission service regulated by the FERC. Customers taking service under the OATT, MS argues, should not bear any portion of the MPSC's costs, which are incurred to regulate firms and services under the State's jurisdiction.

Ruling on Taxes Other Than Income Taxes:

As CECo argues, this expense is more in the nature of a cost of doing business in Michigan than one that can be parsed between regulatory jurisdictions. Nor is the issue as crystal clear as MS suggests. At one point in its reply brief, MS states that MPSC's regulatory actions do not benefit CECo's transmission customers, yet the intervenor argues elsewhere that MPSC's jurisdictional determinations support its particular views on rate base issues. The amount claimed by CECo will be allowed as a reasonable allocation to transmission service of a cost assessed by the State against utilities that operate in Michigan.

ISSUE 2 E -- Revenue Credits

Transmission use by short term and non-firm customers provide revenues that are used to offset the fixed costs that long term firm users are expected to bear. Order No. 888 at 31,738; Order No. 888-A at 30,262. Here, CECo proposes a credit of $4,950,433, derived from wheeling and interconnection revenue ($2,699,333) and intersystem capacity revenue ($2,252,600). The latter figure was derived by allocating to transmission service 31 percent of CECo's test year wholesale coordination sales to non-requirements customers, that being the ratio of transmission to production in CECo's historical cost of service. Michigan Systems argue that this latter calculation does not properly reflect rate design under the OATT. Exs. MS-41 at 12; MS I.B. at 124-125.

MS contends that CECo's FERC Form 1 for 1995 discloses sales for resale energy of 1,352,090 MWh. Based upon this level of sales, and the Company's computed credit, the imputed transmission rate is 1.66 mills per kWh, far below the on-peak hourly rate of 4.6 mills per kWh and off-peak hourly rate of 2.2 mills per kWh that CECo seeks in this proceeding. CECo's revenue credits, MS maintains, should reflect the short term and non-firm rates that CECo will charge, not some proxy value. If CECo's proposed transmission rates are approved, the credits would be far higher than CECo has proposed.

CECo claims to have used an accepted allocation methodology for computation of the credit. Indeed, CECo contends that MS' witness Coles used an allocation comparable to CECo's in testimony he introduced in the Company's 1995 case, Docket No.

ER92-331-000. Tr. at 1422-23. CECo asserts that its 31 percent allocation factor is very generous when its proposed transmission revenue requirement of $110,040,000 is compared to its 1995 total generation cost of service of $1.625 billion. Ex. CE-21 at Schedule 1 and 2. If bundled sales to non-requirements customers were to be priced on the basis of fully allocated cost of both production and transmission, the transmission component would be only about 6.3 percent thereof, CECo argues.

Staff agrees with CECo, contending that MS has failed to show that CECo's proposed allocation is unreasonable. Staff argues that the 31 percent allocation proposed by CECo is based upon a ratio of transmission investment to total production and generation investment, which it claims is a reasonable method of splitting revenues generated from opportunity type transactions between the production and transmission function. Staff R.B. at 24.

Ruling on Revenue Credits:

While it may be possible, indeed preferable, to find a more precise calculation of the revenue credits at issue here than the allocation proposed by CECo, this record does not contain an alternative calculation that has the necessary credibility to warrant departing from CECo's proposed method. The allocation methodology advocated by CECo produces acceptable results and its reasonableness is validated by MS witness Coles' use of a similar allocation in a previous case. MS simply has not demonstrated that a calculation based upon the 1995 FERC Form 1 data would produce a more accurate revenue credit than the allocation offered by CECo. CECo's proposed revenue credit will be adopted.

ISSUE 2 F -- Plant Held for Future Use

Michigan Systems challenge the $6,808,497 amount included by CECo as Plant Held for Future Use because it originally applied to a proposed interconnection project, identified as the "PSI-Line," that has been canceled. Ex. MS-46 at 3. CECo witness Erickson testified on rebuttal that, despite cancellation of the PSI-Line project, CECo plans to use the land and rights-of-way to construct a step-down substation in Branch County, Michigan, to strengthen the system in that area. Ex. CE-73 at 51. CECo further notes that the MPSC approved inclusion in Plant Held for Future Use of a portion of the land and rights-of-way originally intended for the PSI-Line project. Id. CECo contends that this constitutes a sufficient plan to qualify this plant for the category of Plant Held for Future Use. CECo maintains that the Commission long ago dropped any requirement that lands be held under a specific plan to be used within a finite time period, citing Pacific Gas & Electric Co., 16 FERC • 63,004 at 65,020 (1981), aff'd 20 FERC • 61,340 (1982) and Cajun Electric Power

Coop. Inc. v. Gulf States Utilities Co., 47 FERC • 63,024 at 65,056 (1989), modified on other grounds, 59 FERC • 61,041 (1992), remanded on other grounds, sub nom., Gulf States Utilities Co. v. FERC, 1 F.3d 288 (1993).

Staff, also citing to Pacific Gas, points out that CECo has indicated that it plans to construct a new step-down substation on this land in Branch County, tentatively scheduled for year 2004. Staff contends that this is sufficient manifestation of a plan for future use to include the subject land and land rights in the rate base.

Ruling on Plant Held for Future Use:

Pertinent precedent clearly establishes that there is no requirement that a utility have a definite plan to use land and property rights within a finite period to qualify the plant for inclusion in rate base as Plant Held for Future Use. Accounting Treatment for Land Held for Future Utility Use and for Profits or Losses Realized Through sales of Those Lands, Order No. 420, 45 FPC 106 (1970); modified, Order No. 420-A, 45 FPC 340 (1971); Pacific Gas, 16 FERC • 63,004; and Cajun Electric, 47 FERC • 63,024. Here, as argued by CECo and Staff, there is enough of a plan for the prospective use of the land and land rights at issue to qualify for inclusion as Plant Held for Future Use. A specific use has been identified for the land, namely reinforcement of CECo's transmission system in southern Michigan, including construction of a step-down substation in Branch County, within a reasonable time frame, i.e., by the year 2004. Ex. CE-73 at 51. Thus, CECo's proposal is adopted.

ISSUE 3 A -- Rate Divisors - Ludington Pumped Storage Plant

Michigan Systems propose that 917 MW of transmission demand associated with Detroit Edison's entitlement to a share of the output of the Ludington Pumped Storage Facility ("Ludington") be included in developing the denominator by which CECo's annual revenue requirement is divided to derive a rate per kilowatt of service. The proposal is grounded in Detroit Edison's use of CECo's transmission network to deliver the output of Ludington, which is located in western Michigan. Ex. MS-41 at 14. MS contends that the dedicated use of the transmission network to deliver the output of Ludington to eastern Michigan must be accounted for in the denominator, along with network and other point-to-point demands or reservations. MS further argues that the Ludington plant places an unusually high burden on the CECo's transmission network, in that it must be capable of transmitting the obligated amount to Detroit Edison. This burden, MS maintains, should not be neglected. Staff concurs with Michigan Systems' proposal, in principle. Ex. S-28 at 30. However, Staff calculates the appropriate load and divisor addition to be 443

MW, which coincides with the 1995 test year twelve monthly coincident peak ("12-CP") average of Detroit Edison's Ludington entitlement available for delivery across CECo's transmission lines. Ex. CE-68 at 13.

CECo presents testimony of its witness Waits who contends that simplistic addition to the divisor of Detroit Edison's ownership share of Ludington fails to recognize the history and operating procedures of the tight pool arrangement between CECo and Detroit Edison known as the Michigan Electric Coordinated Systems ("MECS"). The two utilities have made reciprocal investments in transmission facilities since 1962 to facilitate an economic dispatch arrangement on a cash-free, but not cost-free basis, CECo contends. CECo further claims that simply adding the number of megawatts attributable to Detroit Edison's ownership share of Ludington to the divisor would ignore the investment in transmission paid by Detroit Edison as part of the reciprocal arrangement. To recognize this investment, it would be necessary to adjust the numerator, as well, the Company argues.

CECo also presents an alternative to full inclusion of the Detroit Edison's share of Ludington in the divisor, contending that the numbers proposed by MS and Staff are far too high because only a small amount of the power generated by Detroit Edison's share of Ludington typically moves across CECo's transmission lines to Detroit Edison. CECo calculates a twelve-month average flow to Detroit Edison to be 36 MW, which accounts for the fact that in only four months of the 1995 test year did the net of all interconnection flow, coincident with CECo's peak, exit CECo.

MS responds to CECo's arguments, contending that there is no basis upon which to conclude that the Michigan pooling arrangement justifies Detroit Edison's avoiding cost responsibility for the Ludington transmission entitlement. Neither are the downward adjustments to the 917 MW entitlement proposed by Staff and CECo justified, according to MS. CECo is committed to deliver Detroit Edison's 49 percent share of the full output of the Ludington plant, and must at all times be capable of delivering the contracted amount of service, MS maintains. This commitment is analogous to a firm, point-to-point reservation, Michigan Systems argue. Accordingly, MS sees no basis for a downward adjustment for actual use. Tr. at 992-96.

Ruling on Rate Divisors - Ludington Pumped Storage Plant:

MS and Staff are correct that it is appropriate to include the transmission demand associated with Detroit Edison's share of the Ludington Pumped Storage Plant in the denominator used to derive a rate per kilowatt of service. This is because Detroit

Edison makes use of CECo's transmission network to deliver the output of the Ludington plant to eastern Michigan. Ex. MS-41 at 14. It would be improper to ignore the burden of this demand on CECo's transmission network. CECo's argument that the potential benefits afforded by Detroit Edison's reciprocal investments in transmission should be reflected in the numerator, if the divisor is adjusted as MS proposes, is unavailing because CECo makes no concrete proposal for such an adjustment. It is clear that the Commission requires cost allocation of firm services. See Minnesota Municipal Power Agency v. Southern Minnesota Municipal Power Agency, 68 FERC • 61,060 at 61,206 (1994). The commitment here is akin to firm, point-to-point service. Tr. at 999. The Commission's Order No. 888 similarly includes in the denominator for point-to-point service and network service the contract demands of all firm customers. Order No. 888 at 31,738. 20/ Because this significant firm demand is not otherwise reflected in the denominator, it must be included.

Next is the argument surrounding the correct share of Detroit Edison's capacity output of Ludington to be included in the denominator. To recapitulate, MS argues for the 917 MW that represent Detroit Edison's full share of the plant's output on the theory that CECo must be prepared to meet that level of demand if called upon to do so. Staff favors 443 MW, which is a calculation of actual usage based upon 1995 test year data. CECo would include only 36 MW, which is based upon an analysis of electron flows during the test year.

MS has the better argument. The intervenor is correct that CECo's transmission network must be capable of transmitting Detroit Edison's full 49 percent ownership share of Ludington. To allocate a lesser amount would not give full recognition to the burden on CECo's network caused by this transmission commitment. Inclusion in the denominator of the lower actual usage of the system in the test year, as proposed by Staff, would not adequately reflect this firm service responsibility and would transfer to other ratepayers some of the cost burden associated with this arrangement. CECo's analysis is even less reliable and would result in practically no recognition of the burden of this large commitment. MS' proposal to include 917 MW in the denominator is thus adopted.

ISSUE 3 B -- Rate Divisors - Generation Capability of CECo's Retail Customers

20/ CECo does not include any coincident peak demands associated with Ludington in the 12-CP transmission demand divisor. Ex. S-28 at 30. Thus, based on this provision of Order No. 888, no removal of demand is necessary.

Michigan Systems and Staff urge inclusion in the rate denominator of the loads of CECo's retail customers who have a portion of their load served by their own generation sources, so-called "behind the meter" generation. Staff suggests 106 MW, based upon a 12-CP method. MS supports the same divisor, but argues that it should be 133 MW, if a 1-CP method is ordered. MS and Staff contend that the Commission's Order No. 888 requires that a network customer's entire load, including load served by generation that is "behind the meter," be included in allocating transmission costs. Order No. 888 at 31,736 and Order No. 888-A at 30,257-61.

CECo contends that this adjustment is inappropriate since there is no evidence that any retail customer of CECo owning "behind the meter" generation is taking unbundled service from CECo. Nor, CECo argues, is there any evidence of a pooling arrangement among these retail customers, making independent generation of these CECo retail customers non-comparable to MCCP member generation.

Ruling on Rate Divisors - Generation Capability of CECo's Retail Customers:

The issue here is the proper allocation of cost responsibility to "behind the meter" loads. The Commission's Orders No. 888 and 888-A plainly require inclusion in the rate denominator of "behind the meter" loads. CECo's arguments are, as MS argues, distinctions without a difference. The 106 MW of CECo's load served by "behind the meter" generation should be included in the load ratio share calculation for determining the transmission costs allocated to network customers.

ISSUE 3 C -- Load Ratio Share Calculation Method for Network Integration Service

ISSUE 3 D -- Annual Cost Divisor for Firm Point-to-Point Service

CECo proposes to use a 12-CP divisor for both the load ratio share calculation for network integration service and for the calculation of point-to-point service rates. CECo offered testimony of its witness Rasmussen, who claimed that the 12-CP approach is appropriate for CECo in light of its relatively flat demand curve. Ex. CE-17 at 8-10. The 12-CP method is also consistent with the Commission's Order No. 888, argues CECo, by pointing to language by the Commission reaffirming use of the twelve monthly coincident peak methodology because the majority of utilities plan their systems to meet their twelve monthly peaks. Order No. 888 at 31,736.

Edison Sault and ABATE argue that CECo's rates for transmission service should be derived using a 3-CP load divisor developed from the three highest consecutive months in a rolling twelve-month load ratio share. Edison Sault's witness, Dr. Axelrod, compared CECo's monthly peaks during its on-peak season (as a percentage of CECo's annual system peak) to the average of CECo's monthly system peaks during its off-peak season (as a percentage of CECo's annual system peak) for the test year 1995. He found the differential to be 21 percent, which he contended was higher than the 19 percent employed by M.E. Small in his guide to FERC ratemaking 21/ as an upper bound for the appropriateness of the 12-CP methodology. Ex. ES-1 at 9-12. Dr. Axelrod's 21 percent differential "corrects" the 19 percent derived by CECo's witness Rasmussen in Ex. CE-17 because Dr. Axelrod concluded that Mr. Rasmussen inappropriately included September in his calculation of peak months. Id. Edison Sault also contends that CECo has an increasingly pronounced summer demand, as reflected in the general decline of the annual to average peak test percentages. Exs. ES-5 at 3; ES-6 at 3. Edison Sault contends the Commission has never adopted the 12-CP methodology where the difference between peak and off-peak ratios is over 19 percent. Southwestern Public Service Co., 18 FERC • 63,007 at 65,034 (1982). When above 19 percent, Edison Sault argues, the Commission has favored 4-CP or 3-CP approaches. Id.; Commonwealth Edison Co., 15 FERC • 63,048 at 65,196 (1981), aff'd, 23 FERC • 61,219 (1983) (Opinion No. 165); Louisiana Power & Light Co., 14 FERC • 61,075 at 61,129 (1981) (Opinion No. 110).

ABATE argues that the 12-CP methodology is appropriate only where a utility cannot plan its system without considering each and every monthly system peak. It contends that there is no evidence that CECo plans its system by looking at each monthly peak. ABATE's witness Dauphinais submitted an analysis of planning criteria from which he concluded that CECo plans its subtransmission system almost exclusively with respect to the three summer peak months, based upon acceptance of a risk of interruption when load is in excess of 80 percent of annual peak. Ex. ABATE-1 at 15; ABATE I.B. at 12. He further asserted that with transmission system power factors higher in the non-summer months than in summer months, less reactive power is required per kW of real power load. Lower reactive power in the summer months translates into less need for reactive compensation by transmission facilities to maintain non-summer system voltages, suggesting to the witness that the 3-CP methodology better tracks cost causation than does the 12-CP approach. Further, ABATE contends that CECo plans its 138 kV and 348 kV bulk transmission system by meeting certain thermal and voltage requirements at 100 percent of annual peak load, which ABATE contends further supports a 3-CP method. The summer peak demands, ABATE states,

21/ M.E. Small, A Guide to FERC Ratemaking of Electric Utilities and Other Power Suppliers (Edison Electric Institute, 3rd ed. 1994).

are distinctly higher than non-summer months, suggesting that the transmission system can be planned by considering only annual peak transmission loads. Finally, ABATE points out that Detroit Edison has agreed to use of 3-CP allocation in Docket No. OA96-76-000. Because Detroit Edison and CECo operate in a tight pool, rates should be designed for the two entities by using the same methodologies, ABATE maintains.

MS agrees with CECo that the 12-CP method should be used to calculate load ratio shares for purpose of charging for network integration transmission service, but argues that firm point-to-point rates should be based upon a 1-CP denominator. MS sees the use of 12-CP for the former purpose as consistent with the Commission's Order No. 888, but urges that the rationale should not be extended further. MS points to the Commission's decision in Allegheny Power System, Inc., where the Commission stated that its conclusion in Order No. 888, that it would no longer summarily reject a firm point-to-point rate developed by using the 12-CP method, does not make use of the 12-CP divisor a change necessitated by Order No. 888. MS I.B. at 139, citing 80 FERC • 61,143 at 61,529-30, n.27. With CECo's current more flexible point-to-point service offering, MS argues, a divisor that captures the increased flexibility but avoids the risk of over-allocation of transmission costs to point-to-point customers must be chosen. A 1-CP approach would meet that need, MS contends. The nature of the service needs to be taken into account, according to MS. MS further asserts that use of a 12-CP divisor for point-to-point service will result in unjustified inconsistency by treating the cost of a MW of reservation-based point-to-point service as equal to the cost of a MW of transmission for the provider's native load. MS concludes that the services are different and the differences in service characteristics make it reasonable to utilize different cost allocation methods.

Staff performed an independent analysis and concluded that the 12-CP method is appropriate. Staff contends that it complies with the Commission's Order No. 888, which it construes as directive on this point. Staff claims that ABATE and Edison Sault have failed to show that CECo plans its system to meet an annual system peak, which Order No. 888 requires for methods other than 12-CP. Staff's witness Oxendine introduces five tests to support his 12-CP recommendation, including three analyses employing averages: (1) an average for five previous years of the difference between purported peak and non-peak months (13.18 percent) Ex. S-28 at 6-7; (2) the ratio of the minimum peak to the annual peak (73.82 percent), which he concluded was high enough to suggest there is no significant peak period; and (3) the average of the twelve monthly peaks to the highest monthly peak (82.6 percent), which was higher than the 81 percent threshold for use of 12-CP, as described in Illinois Power Co., 11 FERC • 61,186 at 61,387 (1980). In addition, Mr. Oxendine performed two tests comparing the number of times non-peak demands exceeded peak demands. Both of these studies support the use of 12-CP, according to Mr. Oxendine. Ex. S-28 at 9.

Ruling on Load Ratio Share Calculation Method for Network Integration Service and Annual Cost Divisor for Firm Point-to-Point service:

Order No. 888 and Commission precedent point squarely in the direction of the use of the 12-CP for the load share ratio calculation. After rejecting the notion that load ratio was an inappropriate basis upon which to allocate costs, the Commission stated:

> We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual peak...are free to file another method if they demonstrate that it reflects their transmission planning.

Order No. 888 at 31,736.

While not requiring use of a 12-CP allocation methodology, the Commission in Order No. 888-A stated that it would reject alternatives unless they were demonstrated to be consistent with the utility's transmission system planning and did not result in an over-collection of the utility's revenue requirement. Order No. 888-A at 30,256.

Edison Sault's attempt to justify use of a 3-CP method relies too heavily on one year, 1995, which was atypical. Ex. S-28 at 8. Its further attempt to show a trend of increasingly pronounced summer peaks also relies too heavily upon the atypical 1995 data. Further, the "annual to average peak test" percentages for the years preceding 1995 are all above the Commission's 81 percent cut-off, confirming the propriety of the 12-CP allocation method. Edison Sault I.B. at 5; Exs. ES-5 at 3; ES-6 at 3. Staff's witness performed a series of tests to determine the appropriateness of the 12-CP allocation. By and large, Staff's witness employed averages of recent years experience to test his conclusion that a 12-CP allocation is appropriate. These analyses are more reliable than the alternative approaches suggested by Edison Sault.

ABATE also fails to demonstrate convincingly that the Company plans its transmission system in a manner other than by analyzing monthly peaks. Demands on the Company's system fall well within the parameters set by the Commission for use of the 12-CP allocation, as Staff argues. Moreover, CECo's non-summer peaks exceed its prior year's summer peaks on many occasions between 1992 and 1996. Ex. S-28 at 10. In sum, there is no persuasive evidence that the use of 12-CP would be inappropriate here as an allocation method for network integration service.

MS contends that even if 12-CP were selected as appropriate for calculation of load ratio shares for network service (a position with which it agrees), a 12-CP methodology should not be applied to point-to-point service. MS, however, fails to show why a 12-CP methodology would be inappropriate for point-to-point service, or, more importantly, why 1-CP would be more appropriate. It argues that the differences in point-to-point service from network service warrant different approaches to cost allocation and rate design, but does not show why such differences point to the propriety of a 1-CP allocation. This deficiency is all the more critical in light of the Commission's decision in Order No. 888, which acknowledged the similarities between network and point-to-point service and recognized that the 12-CP methodology could reasonably be used to allocate costs for both. The differences in the two services noted by MS are not material enough to warrant departing from the general guidance suggested in Order No. 888. The 12-CP allocation is deemed appropriate for point-to-point service, as well as for network service. 22/

ISSUE 3 E -- Annual Cost Divisor for Non-Firm Point-to-Point Service

CECo maintains that there should be no difference in the divisor used to calculate Firm Point-to-Point Service rates from that used to calculate Non-Firm Point-to-Point Service rates. Ex. CE-21 at Schedules 9, 10. MS, on the other hand, contends that a divisor of over 9,200 MW, which represents the total amount of generation (including non-utility generation) connected to CECo's transmission system, should be used for non-firm service. Ex. MS-41 at 17-18. MS argues that unless the denominator for non-firm service is larger than for firm service, pricing for non-firm service will be identical to that for firm service and will not reflect the interruptible nature of the service. MS contends that the Commission's policy is that non-firm transmission prices should reflect the interruptibility of the service and promote efficient use of the system. Order No. 888-A at 30,272. MS points to the Commission's actions in Northern States Power Co., 64 FERC • 61,324 (1993), Order Denying

22/ MS' arguments that customers should be able to vary contract demand and that billing determinants should be measured at the lower of the sum of capacity reservations at their receipt or delivery points are rejected as insufficiently supported and inconsistent with the provisions of Order No. 888.

Reh'g and Granting Clarification, 74 FERC • 61,106 (1996), where the Commission adopted system capacity as the non-firm divisor, as MS is requesting here. Michigan Systems maintain that, since CECo does not discount non-firm service, the higher divisor is necessary to develop a rate that reflects the true character of the service, which is inferior to firm, and thus ought not to be priced identical to firm.

CECo counters this argument with the Commission's decision in AES Power, Inc., 74 FERC • 61,220 at 61,746-7 (1996), where the Commission accepted the transmission provider's use of annual system peak as a proxy for transmission system capability in the design of non-firm rates. CECo contends that its transmission system is not capable of carrying at the same time the power generated by all of CECo's generation resources, including non-utility generators, operating at 100 percent of capability. Using system capacity as a divisor would, according to CECo, completely ignore the need for unused generation reserves in utility planning. CECo further maintains that the Commission has consistently articulated a policy of allowing non-firm rates stated as a ceiling rate to be capped at the firm rate, citing in support Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, FERC Stats. & Regs. (Regulation Preambles 1991-1996) • 31,005 at 31,137 (1994); Order No. 888 at 31,743-44; Order No. 888-A at 30,272. CECo sees the MS position as an attempted end run around the Commission's asserted refusal to compel across-the-board discounts for non-firm point-to-point service. Staff agrees with CECo's position, emphasizing that Michigan Systems' argument runs counter to the Commission's decision in AES Power, Inc.

Ruling on Annual Cost Divisor for Non-Firm Point-to-Point Service:

Were one free to explore the merits of this issue in the absence of the Commission's fairly recent pronouncement on virtually the same issue in AES Power, Inc., one might conclude that MS has the better argument. That the rate for non-firm service has historically been capped at the firm rate is not necessarily license to charge the same rate for both services. Indeed, earlier Commission precedent cited by MS, including Northern States, seems to recognize the intuitive logic of pricing an inferior service at rates lower than the superior service. But the precedent established in AES Power, Inc. is clearly controlling here. The Commission recognized there that the utility's firm customers pay all of the costs of the transmission system, without regard to the amount of energy actually scheduled for delivery, whereas the non-firm customers pay only when the company transmits energy for them. The Commission stated, at 74 FERC at 61,747:

> This is appropriate, given that the transmission system is planned to meet firm load, based upon probable conditions, plus contingency conditions for reliability purposes. The system is not planned to deliver the maximum output of all generating units simultaneously.

MS here argues that non-firm service should be priced based upon the assumption rejected by the Commission above. Moreover, MS fails to distinguish, or even mention, AES Power, Inc. Accordingly, CECo's proposal to use system peak as the rate divisor for hourly non-firm point-to-point service is adopted.

ISSUE 3 F -- Short-Term Divisors

CECo's witness Rasmussen explained how the Company developed on-peak daily rates by dividing weekly rates by five, and off-peak daily rates by dividing weekly rates by seven. Similarly, he stated that hourly on-peak rates should be calculated by dividing the daily rate by sixteen, and that off-peak hourly rates should be calculated by dividing by twenty four. Ex. CE-17 at 9. CECo explains that this proposal represents a modification of the so-called Appalachian pricing method historically accepted by the Commission. 23/ CECo argues that this modified Appalachian proposal provides a reasonable compromise among the interests of the transmission provider, the short-term customer, and the long-term customer who pays the cost of the transmission system.

MS argues that the Commission should adopt an 8,760 divisor for hourly service, contending that CECo has failed to justify use of the Appalachian pricing methodology for short term rates. It contends that CECo seeks to price short term service based upon a fiction that weeks have only five days and days have only sixteen hours, which reduces the rate divisor and increases the unit rate. MS contends that Appalachian pricing will overcharge short term users and is unnecessary, given the governing pro forma tariff terms and conditions. These terms, according to MS, obviate any concern that short term uses will compromise recovery of the Company's system fixed costs by preempting longer term reservations. Michigan Systems argue that the tariff terms make clear that short term service is provided out of left-over capacity, and only if none of the long term users for whom capacity was built want to use it. Reducing the divisor as CECo

23/ Under Appalachian pricing, a uniform rate applicable in all 8,760 hours of the year is developed by dividing annual costs by only 4,160 hours. Appalachian Power Co., et al., 39 FERC • 61,296 at 61,965 (1987). See also American Electric Service Power Corp., 80 FERC • 63,006 at 65,067-69 (1997).

proposes will simply increase the subsidy paid by short-term customers in that period, MS contends.

CECo again responds citing recent Commission precedent. It calls attention to the Commission's decision in IES Utilities, Inc., et al., 81 FERC • 61,187 at 61,833-34, where a modified Appalachian pricing proposal, identical to the one proposed here by CECo, was adopted over the recommendations of the Presiding Administrative Law Judge, who favored 8,760 hours as a divisor. The Commission was persuaded by the actual usage of the applicant's service, namely, that significantly more usage occurs during peak periods than during off-peak periods. The Commission also rejected the argument that time-differentiated non-firm pricing may result in over-collection. CECo contends that the facts here are similar to IES Utilities and supports a finding that its short term divisor proposal is just and reasonable.

Staff agrees with CECo, noting that the Company here proposes not traditional Appalachian pricing, but a modified version where two rates are developed: an on-peak rate applicable for 4,160 hours, and an off-peak rate applicable only for the off-peak hours. Staff reasons that, if a short term customer is using capacity during on-peak hours, it is getting the same use of capacity as a long term customer using the system during that on-peak period and ought to pay the same price. Staff maintains that the Commission agreed that use of peak pricing conformed to the pro forma tariff, and Staff supports CECo's proposal here.

Ruling on Short-Term Divisors:

The Commission's recent decision in IES Utilities, Inc. and its more recent decision in Entergy Services, Inc., 85 FERC • 61,163 (October 30, 1998), adopting a modified Appalachian pricing proposal, points us in the direction of CECo's similar offering here. The facts of this case seem squarely in line with those of IES Utilities, Inc., and the arguments offered by MS do not provide a convincing rationale for a departure from that Commission precedent. Staff's argument that short term usage during the peak period should be priced on the same basis as long term on-peak usage is reasonable. Moreover, CECo's proposal achieves substantial rate justice in that it recovers appropriately from those who take service at the time of the peak 4,160 hours, while basing off-peak rates on a distribution of annual costs over all of a year's 8,760 hours. Thus, CECo's proposal for calculating appropriate divisors for daily and hourly point-to-point transmission service rates is adopted.

ISSUE 4 -- Real Power Loss Factors

CECo's proposed open-access tariff provides loss factors for Point-to-Point and Network Integration transmission service. Those loss factors are 3.86 percent for deliveries metered at the low voltage side of the applicable transformer (below 33 kV) and 3.22 percent for deliveries metered at the high voltage side of the applicable transformer (33 kV and above). 24/ These loss percentages, based upon a study using 1995 data, are calculated by taking the average losses from load flow solutions modeling system conditions at twelve monthly peak demand hours. Ex. CE-4 at 5.

Staff and ABATE contend that power loss factors should be calculated based upon average system losses over 8,760 hours per year, instead of the twelve monthly peaks, as proposed by CECo. Staff contends that the twelve average peak losses are greater than the losses in most of the non-peak hours during the year. Therefore, Staff asserts, when the proposed factors are applied during all 8,760 hours of the year, they will compute more losses than are actually experienced by the Company. Ex. S-8 at 21-22. Staff had proposed a set of loss factors in its initial testimony (Ex. S-8 at 21), and then revised those factors (Exs. S-28 and S-30 at 26). However, late in the proceeding, Staff received a copy of the Company's 1995 actual loss factors from its 8,760 hourly power flows. Ex. S-59. Staff now argues that it is better to compute power loss factors by using the actual data from the 8,760 hourly power flows than by using the factors estimated in its testimony. Staff I.B. at 58. Staff's final recommendations are to use the following factors:

High Side (120 kV and above)	1.71 percent
Low Side (120 kV and above)	2.25 percent
High Side (46 kV)	3.08 percent
Low Side (46 kV)	3.50 percent

Id.

ABATE agrees with Staff that the 1995 actual data on the 8,760 hourly flows should be used to calculate the power loss factors. 25/ ABATE argues that CECo's power loss factors will lead to overrecovery of the Company's revenue requirement because

24/ If a voltage differentiated rate structure is adopted, the real power loss factors, using CECo's 12-CP methodology, would be 1.81 percent for power metered at or above 120 kV, 2.56 percent for power delivered from 120 kV and above lines but metered at distribution voltage, 3.58 percent for power metered at 46 or 23 kV, and 4.20 percent for power delivered from 46 or 23 kV lines, but metered at distribution voltage.

25/ ABATE's recommendations are close to Staff's, but differ slightly. Compare Ex. ABATE-1 at 27 with Ex. S-59.

in the vast majority of hours, loss factors predicated on only the twelve monthly peak hours will overstate actual losses. Tr. at 90; see also Ex. CE-88. Use of the hourly power flow analysis of the 8,760 hours will eliminate this problem, according to ABATE. ABATE's recommendations differ from Staff's, however, as a result of what CECo claims are computational errors on Staff's part, in light of the fact that the real power loss factors are not applied to meter readings at the point of receipt, as Staff assumed. ABATE's recommendations, with which CECo agrees if the factors are to be based upon 8,760 hourly flows in 1995, are as follows:

High Side (138 or 345 kV deliveries)	1.71 percent
Low Side (138 or 345 kV deliveries)	2.30 percent
High Side (46 or 23 kV deliveries)	3.17 percent
Low Side (46 or 23 kV deliveries)	3.73 percent

Ex. ABATE-1 at 27.

Consumers Energy responds that, under Staff and ABATE"s methodology, it will underrecover its actual real power loss costs. CECo claims that calculation of average loss factors based upon losses occurring at the twelve monthly peaks, as it proposes, will prevent shifting loss costs onto CECo's native load customers from other transmission users. Ex. CE-73 at 44. The Company offers Exhibit CE-87, which purports to show that a 1.71 percent loss factor for 345 kV and 138 kV deliveries, derived from CECo's 8,760 hourly flows, would underrecover its actual real power loss costs. ABATE notes, however, that Exhibit CE-88 shows an overrecovery using the 1.81 percent factor derived from CECo's proposed twelve monthly peak power flows for most of the deliveries at 345 kV and 138 kV, and an underrecovery only for deliveries over about 6,600 MW, which occur infrequently. Tr. at 90.

Ruling on Real Power Loss Factors:

For the reasons suggested by Staff and ABATE, it has been shown that loss factors derived from the 1995 actual 8,760 hourly power flows will be more reasonable than the alternative proposal advanced by CECo. Staff and ABATE have demonstrated that power loss factors that are based upon the twelve monthly peak methodology will cause over recovery of power loss costs in most of the hours of the year. Id. CECo's fear of underrecovery if the 8,760 hourly power flow methodology is used is overstated in light of the low number of hours per year that delivery levels triggering higher losses will occur. Id. at 87-90; see also Ex. CE-88. Further, ABATE's proposed factors will be accepted in light of CECo's agreement that they are more accurate than Staff's, if the 8,760 methodology is employed. Staff points out that it should be made clear, if CECo and ABATE's figures are used, that real power loss factors are to be applied to customer billing meter readings at the point of delivery. CECo should so indicate in its tariff.

ISSUE 5 A -- Scheduling, System Control and Dispatch Service - Unit Rate Calculation

CECo defines the Scheduling, System Control and Dispatch Service as a service "required to schedule the movement of power through, out of, within, or into a Control Area." Ex. CE-22 at Sheet No. 109. To support its rate calculation for this service, CECo presents testimony of its witness Rasmussen. Ex. CE-17 at 10-13. According to Mr. Rasmussen, the cost of this ancillary service should include 84 percent of the cost of investment, operation and maintenance associated with the Michigan Electric Power Coordination Center ("MEPCC"). Id. at 11; Ex. CE-4 at 2. This allocation is based on MEPCC's labor costs that are associated with transmission operations. See Ex. CE-5.

Furthermore, according to CECo, this service must include 72 percent of the costs for accounting and billing services in the Transmission Transactions Department. Ex. CE-17 at 11; Ex. CE-4 at 3. Mr. Rasmussen claims that any transaction over 3,000 kW should incur a monthly demand charge of $0.056/kW. Ex. CE-17 at 13; see also Ex. CE-22 at Sheet No. 109. To arrive at this figure, CECo uses an annual revenue requirement of $3,873,000 and a 12-CP denominator. Ex. CE-17 at 12-13.

Michigan Systems do not propose a specific rate, but claim that the appropriate cost denominator for this service should be based upon a 1-CP denominator, and that the divisor for short term transmission should be 8,760 hours. MS I.B. at 154. MS' witness Coles argued that the unit rate should be based on total MECS applicable charges and total system load and that the appropriate center costs should be divided by the total loads. Ex. MS-41 at 19. Furthermore, Mr. Coles testified that the Appalachian method of pricing should not be used because "[s]cheduling is a seven day week process and should not be priced on a five day week." Id. at 20.

Staff agrees that the short term transmission rates for this service should be based on 8,760 hours, but disagrees that the appropriate divisor should be based on 1-CP. Staff R.B. at 41-42. Staff calculated that, based on a $3,873,000 annual revenue requirement, the appropriate monthly rate should be $0.051/kW. Staff explains that its proposed unit rate is lower than CECo's figure because a higher divisor is required for consistency with its positions in Issue Nos. 3 A and 3 B. Staff I.B. at p. 59, citing IES Utilities, Inc., 81 FERC • 61,187 (1997), reh'g denied, 82 FERC • 61,089 (1998).

Ruling on Scheduling, System Control and Dispatch Service - Unit Rate Calculation:

The unit rate calculation should be derived from the revenue requirement identified by the Company and Staff, divided by the 12 CP-based demand, including the higher divisor required because of decisions rendered above in Issue Nos. 3 A and 3 B. 26/ Consistent with decisions rendered above in Issue Nos. 3 D and 3 F, the position advanced by MS, namely that the denominator should be 1-CP, is rejected for the reasons advanced in the rulings on those issues. Finally, short term rates should be based on 8,760 hours. IES Utilities, Inc., 81 FERC • 61,187.

ISSUE 5 B 27/ -- Scheduling, System Control and Dispatch Service - Minimum Charge

CECo proposes a bifurcated rate for scheduling, system control and dispatch service. For transactions of 3,000 kW or less, CECo proposes a minimum transaction charge of $2,031/year (or $169/month or $39/week, depending upon the duration of the individual transaction). Ex. CE-17 at 13; see also Ex. CE-22 at Sheet No. 109. For transactions over 3,000 kW, the proposed demand charge discussed in Issue 5 A would be added to the proposed minimum charge. See Ex. CE-22 at Sheet No. 109. CECo's witness Rasmussen proposes that each customer have a minimum scheduled transaction of 1,000 kW, with a 2,000 kW deviation band, which would allow for a use of 3,000 kW of transmission service. Ex. CE-17 at 12-13.

According to CECo, this minimum charge should be included because it reflects the fixed cost component of providing this service. Id. To support its position, CECo reasons that the resources used to supply this service are affected more by the number of transactions than the size of the transaction. Ex. CE-17 at 12. As an example, Mr. Rasmussen stated that a transmission controller may be able to support 20 transactions of 100 MW, but not 22 transactions of 10 MW. Ex. CE-17 at 12. Citing IES Utilities, Inc., 80 FERC • 63,001, CECo acknowledges that ratemaking must recognize a myriad of factors, which often may be in conflict. Thus, CECo argues that these fixed costs must be recognized as part of this service. CECo R.B. at 97.

ABATE's position is that, if a minimum charge is adopted, it should be no higher than 1,000 kW, which is the minimum that can be scheduled under CECo's proposed tariff. ABATE I.B. at 18. ABATE challenges CECo's proposed rate for two reasons. First, ABATE witness Dauphinais testified that charging for the service at a minimum quantity of 3,000 kW is highly discriminatory to

26/ The calculation should reflect the 106 MW and 917 MW additions made in Issue Nos. 3 A and 3 B.

27/ This issue was mistakenly labeled as Issue 5 C in the joint statement of issues.

those customers with loads between 1,000 kW and 3,000 kW. Ex. ABATE-1 at 34. Second, Mr. Dauphinais challenged CECo's proposed rate because the Company charges weekly rates even for those customers taking service for terms of less than one week. Id.

MS and Staff oppose the use of any minimum charge. MS argues that CECo has incorrectly calculated its scheduling system control and dispatch charges by proposing excessive and discriminatory transaction charges. MS I.B. at 154-157. MS claims that CECO's charge is unsupported because its calculation is wrong. According to MS, CECo developed its minimum charge by using a divisor based on the twelve monthly average peak and asserts that the "appropriate center costs [s]hould be divided by the total loads." Id. at 155. MS further claims that CECo also unreasonably used a five-day week instead of seven-day week in scheduling. Id. at 156. MS continues, arguing that CECo failed to show that it incurs the same costs in scheduling and monitoring a short-term transaction as when it provides service to a longer transaction when using the same transmission system, MS contends. Id.

MS believes that CECo's proposal that all customers pay a minimum charge regardless of use, directly conflicts with the ratemaking principle "that all customers ...bear the cost responsibility associated with their respective uses." Id. at 157, citing Order No. 888 at 31,703. MS claims that CECo's proposed rate discriminates against customers with loads under 3,000 kW. Id. MS witness Coles testified that "for customers of less than 3,000 kW, the transaction charge would mean that the customers would pay more per Kilowatt than larger customers." Ex. MS-41 at p. 20. The charge is large enough, according to MS, that it can make a difference in whether a customer can or cannot engage in a transaction. See Ex. ABATE-1 at 34. In turn, this would prevent CECo's transmission customers, many of whom use CECo's system to deliver their generation, from competing with CECo for power sales. MS I.B. at 157. MS argues that CECo should develop hourly rates for this service. Id.

Staff also characterizes CECo's proposed minimum charge as unjust and unreasonable because the proposed rate does not include any safeguards against over-recovery of expenses. Staff R.B. at p. 42. Instead, Staff agrees with MS that the Company should adopt short term rates reflecting the actual amount of service needed for a specific duration. Id. Staff argues that the scheduling rates must be designed in the same manner as the rates for base transmission service. Id. at 42-3, citing Allegheny Power Inc., et al, 80 FERC • 61,143 at 61,541-42 (1997). Because base transmission rates do not have minimum transactional charges, Staff argues neither should the rates for scheduling service. Id. at 43. Staff argues that CECo's proposed demand charge should be adjusted for duration and applied to all transactions, according to Staff. Staff I.B. at 60.

Ruling on Scheduling, System Control and Dispatch Service - Minimum Charge:

CECo has failed to justify the proposed minimum charge. MS argues persuasively that a transactional charge of this nature can have anti-competitive implications. By charging an up-front fee for each small transaction, smaller customers can be prevented from using openly accessible resources to compete as envisioned in Order No. 888. Staff is right, also, in its position that no showing has been made by CECo to demonstrate that the proposed transaction charge, in concert with the usage charge, will not overrecover the costs of providing the service. The costs of providing this service should be recovered in usage charges.

ISSUE 6 A -- Reactive Supply and Voltage Control From Generation Sources Service - Allocation Percentages

ISSUE 6 B -- Reactive Service - Revenue Requirement

ISSUE 6 C -- Reactive Service - Unit Rate Calculation

CECo determines that 27.7 percent of its generator capability supports reactive power production and that 33.3 percent of its exciter capability is used to control reactive power output of the generator. This results in a weighted average investment of 29.7 percent of generator and exciter resources that are used to produce reactive power. Ex. CE-17 at 13-14. This calculation, plus 0.232 percent of real power production related to reactive power, totals the net production plant resource investments associated with reactive power. Id. Dividing this figure by total production plant investment, CECo derives a 1.46 percent factor for reactive power. Id.

There are two issues raised regarding these calculations. First, CECo's 33.3 percent allocation factor of exciters is based upon a review of the equipment specifications and documentation provided by six of CECo's generators, which CECo contends is a representative sample including plants of varying size and fuel type. CECo I.B. at 74. Staff argues that the exciter allocation factor should be based upon the reactive capability of all generating units, since data for all units is readily available. Accordingly, it proposes a 27.7 percent factor, derived from its analysis of all of the data. Exs. S-8 at 9; S-12 at 5.

Second, Staff also allocates to reactive service the cost of Generation Step-Up Transformers, consistent with its position on Issue 1 E, while CECo did not. CECo I.B. at 73.

The revenue requirement will, of course, be derived on the basis of previous determinations of return and other issues and does not present a separate issue for resolution here.

Turning to the unit rate calculation, MS believes that it should be based upon a 1-CP denominator and that an 8,760 hour divisor should be used for short-term transmission. MS I.B. at 159. Staff maintains that a 12-CP denominator is preferable, but agrees with MS that an 8,760 divisor should be used for short term transmission.

Finally, MS argues that a separate reactive service support charge is unreasonable here absent completion of a refunctionalization of costs, previously deemed to be transmission costs, for facilities which actually perform production functions. MS I.B. at 158. MS contends that CECo has made no effort to achieve more than a partial refunctionalization by assigning production costs to transmission. It needs also to complete the refunctionalization by identifying CECo's transmission costs that should appropriately be assigned to production, MS asserts. MS cites Northern States Power Co., 64 FERC • 61,324 (1993), Order Denying Reh'g and Granting Clarification, 74 FERC • 61,106 (1998), where the Commission advised Northern States that if in the future it sought to refunctionalize certain generation costs to the transmission function, it must consider and be prepared to accept legitimate offsetting refunctionalizations of certain transmission costs to production. Id. at 63,380.

CECo characterizes as a radical notion MS' argument that no charge at all for reactive service be permitted unless a comprehensive study is made of what elements of transmission investment should be refunctionalized to the production function. CECo calls attention to what it describes as a similar challenge that was rejected by the Commission. CECo cites to AES Power, Inc., 74 FERC • 61,220 at 61,744 (1996), and to the initial decision in American Electric Power Service Corp., 80 FERC • 63,006 at 65,074 (1997), which, CECo contends, firmly rejected a similar argument by transmission customers. CECo further maintains that MS' argument calling for a complete refunctionalization study before allowing a reactive service charge is a collateral attack on Order No. 888's determination that all transmission providers' tariffs set forth a separate unbundled charge for reactive service.

Ruling on Reactive Service Allocation Percentage, Revenue Requirement and Unit Rate Calculation:

Staff is correct that an allocation percentage based upon a complete analysis of exciter information for all generating units is preferable to the smaller sample employed by CECo. Also, to be consistent with the determination above in Issue 1 E on GSUs, the costs of GSUs should be included in the reactive service charge, as proposed by Staff. The revenue requirement and unit rate calculations should similarly follow previous determinations on issues affecting these calculations. The unit rate calculation should, as Staff recommends, be based upon a 12-CP divisor in order to be consistent with earlier determinations. An 8,760 hour divisor for short term transmission is also the most convincing alternative available on this record.

As to MS' claim that no charge should be allowed for reactive service pending a complete refunctionalization study, the short answer is that Order No. 888 requires an unbundled charge for this service and the proposal on the record is sufficiently supported to be deemed just and reasonable. Like other issues in this case, however, this is one where CECo seems to have one foot in the old transmission world and one in the new. At some early point in the future, it will be necessary for CECo, in order to more properly structure rates under the open access regime envisioned by Order No. 888, to conduct the type of refunctionalization analysis advocated by MS. This should be done at the earliest opportunity.

ISSUE 6 D -- Reactive Service - Recognition of Customer-Supplied Reactive Support

This issue concerns the extent to which the MCCP should receive a credit against the cost of service for reactive power supplied to CECo from generating units owned by MCCP's members. CECo proposes that only the MCCP members' 6.69 percent ownership share of the Campbell 3 generating unit should entitle MCCP members to any reactive power credit. This is because CECo does not have the operational ability or contractual authority to dispatch other MCCP-owned units to produce reactive support on demand. CECo contends that, under the guidance provided by Order Nos. 888-A and 888-B 28/, MCCP's local generation does not provide the type of reactive support necessary to qualify as a partial credit against charges for reactive service. CECo I.B. at 76. Staff agrees that only if CECo has the ability to control MCCP's generating units should MCCP be entitled to the credit. Accordingly, Staff would allow the credit only for the unit that is jointly owned by CECo and MCCP, namely the Campbell 3 facility.

On brief, MS does not argue that other MCCP units than Campbell 3 are entitled to a credit against charges for reactive

28/ Order No. 888-A at 30,228; Order No. 888-B at 62,094.

service, but instead maintains that Michigan Systems' units can satisfy the Commission's requirements, citing arrangements that CECo has made with other non-utility generators. MS I.B. at 161. CECo opposes what it suggests is an attempt by MS to negotiate in its brief some type of reactive service compensation arrangement for MCCP members. CECo maintains that its currently filed Network Service Agreement for MCCP (Ex. CE-79) already provides an adequate vehicle for facilitating reactive power supply compensation.

Ruling on Reactive Service - Recognition of Customer-Supplied Reactive Support:

The record will support a credit against charges for reactive power for MCCP's 6.69 percent ownership share of the Campbell 3 unit only. MS no longer argues for additional credits, recognizing that other MCCP member-owned generating units are not under CECo's control to produce reactive power on demand. The argument presented on brief by MS that transmission customers should be able to obtain credits for the reactive supply their generators provide under arrangements similar to those made with certain non-utility generators is beyond the scope of this proceeding.

ISSUE 7 -- Regulation and Frequency Response Service

ISSUE 7 A -- Annual Revenue Requirement
ISSUE 7 B -- Unit Rate Calculation
ISSUE 7 C -- Purchase Obligation

These issues overlap and are resolved below.

The Commission defines Regulation and Frequency Response service as:

> [a service] necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz) [...] accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow moment-by-moment changes in load. 29/

CECo asserts that for its operations, the appropriate annual revenue requirement for regulation and frequency response is $712,605,000 times an allocation factor of 1.65 percent, or

29/ Order No. 888 at 31,960.

$11,758,000. In calculating the $712,605,000, CECo claims that the generation investment should include units dispatchable through telecommunications systems but not equipped with Automatic Generating Control ("AGC"), as well as those that are so equipped. CECo I.B. at 77; see also Ex. CE-89 at 3. CECo argues that these units should be included because they are capable of providing Regulation and Frequency Control. Id.

In calculating the allocation percentage of 1.65 percent, CECo proposes to take the 6 percent operating reserve requirement for the year 1995, equal to 432 MW, and divide it by the annual dispatchable generation of 6,550.4 MW. CECo I.B. at 78. Thus, CECo comes up with 6.6 percent of dispatchable generation, which it argues should be allocated towards the rates for the ancillary services of Regulation and Frequency Response, Spinning Reserve and Supplemental Reserve. Ex. CE-17 at 15. Next, CECo proposes that the total allocator of 6.6 percent be divided in the following manner: 25 percent to Regulation and Frequency Control, 25 percent to Spinning Reserve and 50 percent to Supplemental Reserve Service. Id. This leads to respective cost allocators of 1.65 percent, 1.65 percent and 3.3 percent. Id.

Staff proposes a slightly lower annual revenue requirement of $698,390,924 with a 1.31 percent allocation factor, or $9,148,922. Staff's revenue requirement figure is lower than CECo's because its calculation follows certain adjustments it has proposed as part of its case in this proceeding, including rate of return, selection of plant providing service and deletion of GSUs. Staff R.B. at 46. MS supports Staff's proposal. MS I.B. at 162.

According to Staff witness Smith, only those units equipped with AGC should be considered as providing capacity for the Regulation and Frequency Response Service. Ex. S-8 at 10. Staff asserts that the only generator units likely to provide this service are the following: Campbell 1 & 2, Cobb 4-5, Whiting, Kern 1 & 2, Kern 3 & 4, Weadock 7 & 8 and the Ludington Pumped Storage unit. Id. Except for CECo's nuclear, peaking and run-of-river hydro units, all CECo units have AGC controls. Id.

Staff's allocation percentage for this service is lower than CECo's. Staff claims that the allocation percentage for Regulation and Frequency Response should be 1.31 percent. Staff I.B. at 64. Staff bases its allocation on hourly load deviations.

CECo proposes a monthly rate of $0.17/kW based on its proposed allocation factor of 1.65 percent. On the other hand, Staff proposes that the appropriate monthly rate for CECo's Regulation and Frequency Response should be $0.11/kW based on an allocation factor of 1.31 percent. Staff I.B. at 65. Staff's proposed unit rate is 29 percent lower than CECo's because Staff disagrees with CECo's generating investment amount, its allocation percentage and its kW divisor. See Ex. S-35 at Schedule 3.

MS does not propose a rate for this service, but claims that the annual cost denominator for ancillary services should be based on 1-CP, the same as in the case of point-to-point transmission service. MS I.B. at 162.

CECo proposes a customer purchase obligation of 1.5 percent. CECo I.B. at 78. CECo computes this figure by allocating the 6 percent operating reserves in the following manner: 25 percent for Regulation and Frequency Response (1.5 percent), 25 percent for Spinning Reserve (1.5 percent), and 50 percent for Supplemental Reserve (3.0 percent). Id. CECo believes that it is impossible to develop "a scientifically accurate way of making an allocation" between Regulation and Frequency Response and Spinning Reserves and that an equal split would facilitate administration for both CECo and its customers. Id.

Staff argues that the appropriate purchase obligation for the Regulation and Frequency Response Service should be 1.31 percent. Staff I.B. at 65. Although Staff agrees with CECo's total 6 percent operating reserves, it disagrees with CECo's proposed manner of allocating it. Staff witness Smith explained that according to East Central Area Reliability ("ECAR"), at least 3 percent of the operating reserves must be spinning reserves and located within the utility's control area. Ex. S-8 at 14, citing Ex. S-13 at 4. Staff asserts that the spinning reserve portion is used to provide load regulation and system frequency control. Ex. S-8 at 4. The remaining 3 percent of capacity may be off-line but must be capable of serving the load within ten minutes. Id. Staff argues that this 3 percent should not be split equally, as CECo proposed. Staff R.B. at 47. Instead, Staff developed a 1.31 percent customer purchase obligation for Regulation and Frequency Response, and a 1.69 percent purchase obligation for Spinning Reserve Service. Id. at 47. Mr. Smith explained that it is reasonable to calculate the level of reserves needed by CECo for regulation service through the following method: 1) calculate the hour-to-hour deviations using CECo's hourly load data in FERC Form No. 714; 2) calculate the average of these deviations and divide this average by 2; 3) divide the number obtained in step 2 by CECo's 12-CP load; and 4) express the number obtained in step 3 as a percentage. Ex. S-8 at 10-11; see also Ex. S-16. Mr. Smith explained that in the second step, it is necessary to divide by 2 in order to account for hourly deviations that may be either above or below the scheduled amount. Ex. S-8 at 11-12; see also Ex. S-18.

Mr. Smith's proposed method is based on the following assumptions: "(1) load growth (or drops) on a linear basis during the hour; (2) the instantaneous variations in load are relatively small compared to the hourly load change; (3) a customer serves its load by block-scheduling its average hourly energy needs from an entity either inside or outside the control area; and (4) [CECo] does the same to meet its hourly load." Ex. S-8 at 11. According to Mr. Smith, the load regulation requirement can be used to describe additional capacity required hourly to match to generation load. Id. CECo argues that Staff failed to show that these significant assumptions apply to CECo's operations.

Furthermore, Staff believes CECo's open access tariff is silent as to the customer purchase obligation for this service and that it should provide the following language:

> A Transmission Customer purchasing Regulation and Frequency Response service will be required to purchase an amount of reserved capacity equal to 1.31 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service or 1.31 percent of the Transmission Customer's Network Load for Network Integration Transmission Service. The billing determinants for this purchase will be reduced by any portion of the 1.31 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

Id. at 13. CECo argues that this assertion is incorrect because "Ex. CE-22 states in Sheet No. 112 that the customer must secure this service 'in an amount of 1.5% of Customer's Reserved Capacity or Network Load, as the case may be.'" CECo R.B. at 100.

Ruling on Regulation and Frequency Response Service Issues:

Order No. 888 specifically defines Regulation and Frequency Response as being "accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment)." 30/ Staff is correct in including only those units equipped with AGC in its proposed generation investment for this service. The fact that these units are dispatchable through telecommunications systems does not infer that they provide Regulation and Frequency Response service.

The North American Reliability Council ("NERC") Operating Policy for Generation Control and Performance specifically states

30/ Order No. 888 at 31,960.

that, "[e]ach CONTROL AREA shall maintain generating regulating capability, synchronized to the INTERCONNECTION, that can be increased or decreased by AGC to provide for adequate system regulation and Control Performance." Ex. CE-6 at 4. Thus, NERC specifically requires that the generators responsible for this service be responsive to AGC. CECo fails to show that the units it proposes to add to the revenue requirement determination for this service meet these standards.

Further, Staff's allocation percentage is supported by the evidence and recent Commission decisions. Accordingly, it is preferable to the allocation proposed by CECo, which was determined to preserve administrative convenience.

The Commission has addressed the method of calculating the Regulation and Frequency Response (also called load following service) and showed that it is not impossible to develop a scientifically accurate way of making an allocation. Allegheny Power Service Corp., 85 FERC • 61,275. Where no actual data demonstrating the moment-to-moment fluctuations in load on the system was available, such as in this case, the Commission adopted an average of all hourly load changes during the year. Id. at 62,120.

In the initial decision in Allegheny Power, the Presiding Judge noted that the average of all hourly load changes during the year, rather than the average of monthly system peaks, is appropriate because "[regulation and frequency response] is intended to respond to fluctuations in load that occur constantly." Allegheny Power Service Corp., 77 FERC • 63,024 at 65,173 (1997). He further explains this is so because "cost incurrence for load following does not occur at the peak...and does not address additional capacity or generation at time of peak only." Id. Moreover, the Presiding Judge decided that the load variation must be divided by 2, as the amount of generation a customer scheduling its load is providing exceeds energy for a portion of the hour. Thus, the regulating margin must be provided only when the customer's load is in excess of the average for the hour. Id. at p. 21; see also Kentucky Utilities Co., 85 FERC • 61,274 at 62,107-09. Staff's proposal in this case follows the basic method used in Allegheny Power and Kentucky Utilities.

In addition, ECAR has recently adopted a separate 1 percent minimum for regulation and frequency response. See Allegheny Power, 85 FERC at 62,121; Kentucky Utilities, 85 FERC at 62,109. Staff's proposed figure of 1.31 percent for regulation and frequency response service is reasonable in light of this requirement. CECo's rationale is unsupported by the evidence and is purely arbitrary.

Based on this methodology, the regulation and frequency response percentage for CECo's system requires that the 75 MW regulation margin be derived by dividing the load change of 150 MW by 2, an that it be spread over the 5,747 MW average twelve monthly peaks. This leads to an allocation factor of 1.31 percent. Thus, I adopt Staff's proposal regarding the annual revenue requirement (to be adjusted consistent with relevant findings herein), unit rate calculation and purchase obligation for Regulation and Frequency Response Service.

Finally, the tariff language proposed by Staff witness Smith is adopted since it explicitly allows for an adjustment of 1.31 percent to the billing determinants if the transmission customer chooses to obtain Regulation and Frequency Response Service elsewhere.

ISSUE 8 A -- Energy Imbalance Service - Capacity Charge

In Order No. 888, the Commission determined that a transmission provider must offer Energy Imbalance Service within and into its control area. Energy Imbalance is defined as "the deviation between the scheduled and actual delivery of energy to a load in the local control area over a single hour." Order No. 888 at 31,717. The Commission further in that Order provides for a deviation band of plus or minus 1.5 percent of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the transmission customer's transactions, with the expectation that imbalances would be eliminated within a reasonable period (usually 30 days). Imbalances within the deviation band that remain uncorrected and imbalances outside the deviation band would result in charges to the transmission customer. Id. at 31,960-61.

CECo asserts that for imbalances outside the 1.5 percent deviation band, there should be a capacity charge of $50/kW during certain critical periods when CECo's spinning reserves drop below 3 percent. CECo I.B. at 79. CECo further proposes a demand charge of $2.42/kW per day for energy imbalances outside the deviation band during CECo's on-peak non-critical periods. 31/ Id. CECo claims that it should be allowed to include capacity charges for Energy Imbalance Service provided outside the deviation band to compensate it for providing generation capacity for this service and to preclude customers from paying penalties for excessive amounts of Energy Imbalance Service instead of securing adequate generating capacity to meet their firm load. Id. CECo contends that the issue is "how high this non-cost based rate should be to deter the undesirable

31/ Hereinafter these proposed charges are referred to as "capacity charges."

practice of taking energy outside the Commission-prescribed deviation band." CECo R.B. at 101.

At the time the parties filed their briefs, the Commission had not provided guidance on Energy Imbalance Service pricing. Thus, CECo examined the regulation of natural gas companies for parallel pricing principles. Specifically, CECo argues that Commission policy in the gas industry recognized the need for penalty rates to ensure operational integrity of a utility during critical periods. CECo R.B. at 101, citing Northern Natural Gas Co., 77 FERC • 61,282 (1996), mod. on reh'g., 78 FERC • 61,355 (1997).

CECo witness Waits testified that the energy imbalance charges are aimed to keep the system in a reliable state. Ex. CE-4 at 4. Mr. Waits asserted that CECo will face financial penalties if it does not meet control performance requirements which are made worse by energy imbalances caused by other utilities. Id. at 4-5. On rebuttal, he claimed that Energy Imbalance Service is the most appropriate means of creating incentives to keep actual interconnection power flow equal to the flow scheduled. Ex. CE-68 at 5-6. CECo witness Rasmussen rationalized that, since Energy Imbalance Service is infrequently used, energy-only billing is insufficient to recover the capacity cost of providing this service. Ex. CE-17 at 19-20. CECo asserts that only 1 percent of the hours during the one year period from December 1996 to November 1997 would be considered on-peak critical periods. CECo R.B. at 101.

Staff, Michigan Systems, ABATE and the City of Holland argue that there should be no capacity charges. Michigan Systems challenge CECo's justification for such charges contending that CECo failed to show that it actually installed or reserved generation capacity for this service. MS R.B. at 51. Michigan Systems also assert that CECo fails to show that the proposed energy imbalance charge would deter customers from electing to take the energy imbalance service rather than securing other resources. Id.

Michigan Systems, Staff, ABATE and City of Holland claim that CECo's proposed rates are excessive. MS I.B. at 167-70; Staff I.B. at 67-71; ABATE I.B. at 21; Holland I.B. at 8-16. Staff asserts that CECo's capacity charges are "inappropriate, unsupported, and vastly overpriced." Staff I.B. at 67. Staff explains that CECo's proposed rates include, in addition to the capacity charges, an energy charge of $100/MWh, or 110 percent of the cost of replacement energy, whichever is greater, during on-peak hours, and $50/MWh or 100 percent of replacement costs, whichever is greater, during off-peak hours. Id.; Ex. S-1 at 13. Staff believes that CECo's charges for all services outside the deviation band should be limited to the greater of 110 percent replacement cost or $100/MWh energy charge, and that no capacity charges should apply. Staff I.B. at 71; Ex. S-1 at 14.

City of Holland and Michigan Systems argue that the $100/MWh energy charge will serve as sufficient incentive for customers to avoid imbalances because the resulting penalty is higher than the cost of replacement energy. Holland I.B. at 13; MS I.B. at 164-5. MS suggests that the charge is not so high that it would punish customers for inadvertent transmission. MS I.B. at 165. Staff agrees that the capacity charges are unnecessary, contending that they will fail to accomplish their intended purpose of signaling customers to stay in balance. Staff I.B. at 68-9.

Staff witness Oxendine testified that the demand charge proposed by CECo cannot be justified because the proposed energy charge for those services outside the deviation band will cover all the energy costs, as well as contribute towards the fixed costs. Ex. S-1 at 15-16. 32/ Michigan Systems' witness Reising also testified that the proposed energy charge is more than five times the incremental cost for the MECS during 1996 and, since the energy charge is substantially greater than two times the cost penalty policy that the Commission has adopted for other provisions, the energy charges alone ought to provide incentives for good scheduling. MS I.B. at 166-67. Staff, Michigan Systems and the City of Holland argue that the energy charge alone will fully compensate CECo and act to deter its customers for mischeduling. Staff I.B. at 70.

ABATE, too, opposes the proposed capacity charge, arguing that it is arbitrary and punitive, rather than cost-based. ABATE I.B. at 21. To adopt CECo's proposed charges, ABATE contends, would help perpetuate CECo's market power by dissuading customers from seeking alternative suppliers. Ex. ABATE-1 at 32. ABATE further recommends that a transmission customer be charged at the greater of $100/MWh or 110 percent of CECO's avoided cost in meeting a customer's shortfall for on-peak periods and at the rate of $50/MWh or 110 percent of CECO's avoided cost of meeting

32/ Staff witness Oxendine explained that, for example, in 1995, CECo's cost of providing the last kWh of energy was less than $40/MWh for almost 99 percent of all hours, and it was less than $20/MWh for the majority of the hours. Ex. S-1 at 14-15. Thus, he stated, by paying an energy cost of $100/MWh, the transmission customer is already paying at least $60/MWh towards CECo's fixed costs. Id. at 15. Mr. Oxendine further explained that, even in the rare situations where the energy costs will rise above $100/MWh, the customer will pay a rate of 110 percent of replacement costs, and thus contribute at least $10/MWh towards CECo's fixed costs. Id.

the customer's shortfall for off-peak periods. This, ABATE contends, will strike a balance between cost-based rates and the provision of adequate incentives to discourage use outside of the deviation band. ABATE I.B. at 21. ABATE deems it "absolutely critical that anti-competitive rates and charges for this service not be adopted" because they will affect both wholesale and retail rates, the latter being more sensitive to penalty rates and charges. Id. 33/

Staff asserts that CECo's proposed penalty Energy Imbalance Service charge is not cost justified because it is 16 times higher than the cost of a combustion turbine that is likely to be used for this service. Staff I.B. at 68, citing Tr. at 901-02. Staff also argues that the penalty is out of proportion to the violation because the demand charge is the same for the entire month, even where the imbalance may have occurred only for one hour of the critical on-peak period. Id. Lastly, Staff argues that CECo did not justify its proposed "critical periods" and that it failed to provide guidelines for distinguishing between critical and non-critical periods. Staff I.B. at 70. Staff asserts that in order to provide incentives for proper scheduling, the customer must first be notified that it is within the critical period and thus likely to incur the penalty. Id. at 71. Staff disagrees with CECo's argument that by rescheduling power the customer would avoid the penalties, because Staff finds that the customer would not even be aware of its deviation, and that the price signal may fail to reach the customer in time. Id.

City of Holland characterizes the penalty as "a random event that is poorly connected to desired behavior." Holland I.B. at 12. Moreover, it claims that CECo's own failure to meet its spinning reserves may lead to application of the penalties to transmission customers. Id. In reply, CECo argues that this is not an issue because it is willing to allow transmission schedule changes on 20-minute notice and that ECAR members are expected to recover from loss of a generating unit within 10 minutes. CECo R.B. at 103-104.

CECo rebuts Staff and intervenors' position, contending that the charges for imbalances outside the deviation band are designed to be a penalty for mis-scheduling by transmission users, and thus, they do not have to be cost-based as long as they are reasonable. CECo R.B. at 101. City of Holland replies by stating that, "[w]hile penalties are not required to be cost-

33/ ABATE argues in its Reply Brief that penalty charges should not be applied to imbalances inside the deviation band. ABATE R.B. at 14-15. Since this was not an issue identified as contested, no discussion is included on this matter herein.

based, the utility should set its penalties at a level sufficient to promote good utility practice by its customers, but not to become overly punitive." Holland I.B. at 13. Michigan Systems also argue that although the price for energy imbalance is supposed to serve as a disincentive for improper behavior, the disincentive rate must be reasonably set "because a rate set too high could be exploitative and exorbitant." MS I.B. at 164, citing Florida Power & Light Co., 66 FERC • 61,227 at 61,530 (1994).

Michigan Systems further claim that even if the capacity charge would provide some incentive for good scheduling when the charge is first incurred, it will no longer continue to motivate behavior in the next hour. MS I.B. at 167. Moreover, Michigan Systems argue that the capacity charges actually will lead to bad scheduling practice through uneconomic dispatch and the intentional generation of more energy by the MCCP because the consequences of incurring the charges are so high. Id. at 169-170.

CECo claims that Staff's proposed rate of $100/MWh is insufficient. CECo's witness Rasmussen claims that Staff's proposed $100/MWh would not even cover CECo's variable costs for its combustion and generation units. Ex. CE-17 at 19-20. According to Mr. Rasmussen, the variable costs for these units exceed $180/MWh and fuel costs alone for these generators average $83/MWh. Id.; see Ex. CE-24. Moreover, Mr. Rasmussen asserted that excessive use of Energy Imbalance Service outside the deviation band may reduce CECo's ability to serve native load customers. Ex. CE-17 at 18. However, Mr. Rasmussen admitted on cross examination that the $100/MWh is greater than the actual replacement cost in almost all hours. Tr. at 868. He also recognizes, that where no other costs are involved, the 110 percent replacement cost would be available to cover some capacity costs. Id. at 872.

City of Holland claims that CECo's penalty argument relying on similar pricing mechanisms in the regulation of natural gas companies is misplaced for several reasons. First, City of Holland argues that, unlike the natural gas industry, capacity charges for energy imbalances are not unauthorized use penalties, but rather are rates for a contracted-for ancillary service, and thus, must be cost-based. Holland R.B. at 3. Second, the City of Holland distinguishes the flow between electric systems from flows on natural gas pipelines. It argues that natural gas companies have several mechanisms available to provide reasonable resolution of imbalances without penalty, which do not exist for energy imbalances. Id. at 4-5.

Staff also places emphasis on the operational differences in the natural gas industry and argues that "because storage, pressure needs and configurations are different on gas and electric systems, it is not reasonable to extend concepts about imbalance and scheduling penalties from the gas pipeline to the electric utility industry." Staff R.B. at 49. Furthermore, Staff argues that CECo failed to show that excessive imbalance service during the time when the highest penalty charge would apply -- 1 percent of total hours -- threatened system integrity. Id. at 50. Thus, Staff concludes that CECo failed to demonstrate conditions similar to those in Northern Natural.

City of Holland further argues that CECo's proposed penalty rate is unreasonable in light of the Commission's policy because the Energy Imbalance Service capacity charges proposed by CECo are significantly higher than twice the corresponding rate for transmission service. Holland I.B. at 8-9. It argues that, under Allegheny Power, the proposed penalties would be accepted only if "they are capped at a level equal to twice the standard rate for the service at issue." Id. at 9, citing Allegheny Power Systems, Inc., et. al., 80 FERC • 61,143 at 61,545-6 & n.131. Michigan Systems also address this issue by arguing that charging twice the utility's highest rate provides sufficient incentive to guard against relying on other systems. MS I.B. at 166, citing Indiana Michigan Power Co., 44 FERC • 61,313 at 62,078-9 (1988).

Additionally, City of Holland argues that CECo's proposal is inconsistent with Order No. 888 because, although a transmission customer is required to acquire Energy Imbalance service, "it may do so from the transmission provider, a third party or self-supply." Holland I.B. at 13, citing Order No. 888 at 31,715-16. By arbitrarily penalizing the transmission customer, CECo removes the customer's opportunity to choose its services and penalizes even in those situations where the customer cannot control inadvertent exchanges of power. Holland I.B. at 14. Michigan Systems claim that no control area operator can totally prevent inadvertent energy exchange. MS R.B. at 53-4.

City of Holland also argues that Commission policy requires that emergency situations caused by loss of facilities should be addressed in the transmissions customer's service agreement rather than in the Energy Imbalance Service. Holland I.B. at 14, citing Order No. 888-A at 30,233; Order No. 888-B at 62,092. Lastly, the City of Holland argues that if such penalties are approved, CECo should be ordered to credit such penalty revenues to its cost of service in order to lower transmission rates for the customers to avoid inappropriate profits. Holland I.B. at 15.

CECo further supports its position by claiming that it expects to be subject to NERC-imposed penalties for non-performance. CECo I.B. at 82. City of Holland claims that this argument is meritless because no such penalties currently exist nor does NERC expect to resolve potential penalties until January

2000. Holland R.B. at 6-7. City of Holland states that a utility cannot collect rates to recover potential unknown and unmeasurable costs. Id. at 7, citing 18 C.F.R. • 35.13(d)(1)(ii). Staff argues that CECo is not likely to experience such penalties from NERC anyhow, because it is not possible to determine from which system the inadvertent energy imbalance originated. Staff R.B. at 51, citing Tr. at 1213.

Ruling on Energy Imbalance Service - Capacity Charge:

I conclude that CECo has not demonstrated the propriety of its proposed capacity and demand charges for imbalances outside the deviation band. First, the need for penalty charges of the nature proposed by CECo has not been firmly established. The analogy to the gas industry, particularly the Northern Natural precedent, is not on all fours, as Staff persuasively argues. The complex scheme of scheduling and imbalance penalties used in the case of gas pipelines are designed for different purposes. Scheduling penalties are set to maintain efficient pipeline operation and capacity utilization. Imbalance penalties are provided to discourage customers from tying up or depleting storage through over or under-takes of gas. Tennessee Gas Pipeline Co., 50 FERC • 61,154 at 61,458 (1990). The concepts applicable in the gas industry, which involve storage, capacity, and pressure needs, are not necessarily transferable to the electric sector. While the basic idea of trying to stimulate proper planning and scheduling behavior among customers using the service is common in the circumstances of both industries, the need for and the mechanisms for providing proper incentives will not necessarily be the same. Here, CECo has not made the threshold showing that penalties as severe as proposed are required because of severe conditions, operational behavior, or threats to system integrity, all important considerations in the establishment of gas industry penalty regimes.

Moreover, it is clear that CECo's proposal has not been well thought through, in that it is uncertain to achieve the desired effect of influencing proper scheduling behavior. As City of Holland argues, the penalty is not timed in a way that is likely to change behavior. Holland I.B. at 12. In addition, the level of the proposed capacity charges is high enough to raise a concern about possible unintended anti-competitive consequences. The proposed capacity charges are well in excess of the cost of equipment likely to be used to supply this service (See Ex. S-1 at 13), well in excess of the cost of incremental generation on MECS (See Ex. MS-16 at 66-67), and are substantially above the two times cost penalty policy that the Commission has adopted for other provisions. See Allegheny Power, 80 FERC at 61,545-6 & n.131.

While the capacity charges proposed by CECo have not been shown to be justified, the record supports the need for some charges for imbalances outside the deviation band to discourage reliance upon the availability of this service for purposes other than that for which it is intended. Parties opposed to CECo's capacity charges have argued that all or elements of CECo's energy charge proposal for imbalances outside the deviation band will suffice to satisfy the need for some pricing mechanism that will influence good planning and scheduling behavior. To recapitulate, CECo proposes to apply an energy charge consisting of the greater of $100/MWh, or 110 percent of the cost of replacement energy, during on-peak hours, and $50/MWh, or 100 percent of replacement energy costs during off-peak hours. Staff's position is that all positive energy imbalances over the 1.5 percent deviation band be subject to a charge that is the greater of $100 per MWh, or 110 percent of the Consumers' system incremental cost. Ex. S-1 at 14. Other parties would apply the CECo formulation of energy charges which differentiates between on-peak and off-peak periods, applying to the off-peak periods, a rate that is the greater of $50 per MWh or 110 percent of the cost of replacement energy.

As Staff's witness Oxendine testified, the proposed energy charges for service outside the deviation band are designed to cover all energy costs and make a contribution to fixed costs. See Ex. S-1 at 15-16. They should, accordingly, provide sufficient recompense to CECo for use of its service beyond the bounds of the deviation band. Moreover, because the proposed energy charges are well above the incremental cost of generation from sources available to CECo's transmission customers (See Ex. MS-16 at 66-67), they should provide a sufficient incentive for good scheduling. Here, CECo's argument, id. at 67, that the potential energy charge of $100/MWh is a minor charge incapable of influencing customers to control energy imbalances, is supported by testimony describing a projected revenue requirement deficiency. This testimony misses the counter-argument offered by MS, among others, that the energy charge is high enough to provoke proper scheduling behavior without wreaking unintended consequences, such as the intentional generation of more energy by MCCP than might have resulted from implementation of the much higher capacity charges that have been proposed by CECo. Moreover, the imposition of onerous charges unrelated to the cost of providing the service and higher than necessary to influence proper scheduling behavior might discourage otherwise economically desirable transactions.

Finally, in circumstances like these, the Initial Decision in The Detroit Edison Co., 84 FERC • 63,006 (August 13, 1998), reached the conclusion that a similar capacity charge proposal of Detroit Edison was lacking support, while a Staff proposal to rely on energy charges alone for imbalances outside the deviation band was adopted. Id. at 65,038-40.

For the above reasons, I find that CECo's proposed capacity charges have not been shown to be just and reasonable. CECo's proposed energy charges alone should apply to imbalances outside the deviation band. 34/

ISSUE 8 B -- Energy Imbalance Service - Payment of Accumulated Energy Imbalance Owed to Customer

CECo proposes to credit customers 75 percent of CECo's average decremental cost when the energy imbalance is within the deviation band (2 MW minimum) and not returned in kind by CECo by the end of the transaction period or billing month. See Ex. CE-17 at 16; Ex. CE-22 at Sheet Nos. 116-117. CECo witness Rasmussen defines decremental cost as "the actual replacement energy price minus any redispatching or other costs due to generation supply adjustments caused by the transmission customer s excess energy supply." Ex. CE-17 at 16. CECo also proposes that there should be no payments to the transmission customers for energy imbalances for energy supplied outside the deviation band. Ex. CE-22 at Sheet Nos. 116-117. CECo argues that its proposal takes into consideration necessary incentives for proper scheduling practices. CECo I.B. at 83.

Staff, ABATE, and City of Holland propose that CECo pay to the customer 90 percent of CECo's decremental cost where the imbalance is both within and outside the deviation band. Staff and the City of Holland argue that by setting a 10 percent penalty for over-supply of energy, CECo would provide sufficient incentive for proper scheduling and would be consistent with the 10 percent penalty for under-supply of energy. Staff I.B. at 72; Holland I.B. at 17; see Ex. S-1 at 14. Staff explains that virtually every other utility credits its customers 90 percent of the decremental cost and that CECo has no cost or operational reasons why it should be treated differently. Staff I.B. at 73. Staff states that CECo does not have to pay for under or over-supply, and thus, not giving proper credit to customers when the energy imbalance is outside of the deviation band is unfair and unreasonable. Id. at 72.

Michigan Systems propose that CECo should pay customers the lesser of 90 percent of CECo's decremental cost or the transmission customer's replacement cost regardless of whether the imbalance is within or outside the deviation band. MS I.B. at 172. Michigan Systems label CECo s proposal not to compensate for energy deliveries outside the deviation band as mere "confiscation". Id. Keeping over-deliveries without making

34/ I find no persuasive reason to adopt Staff's apparent position that there should be no differentiation between peak and off-peak charges. See Ex. S-1 at 14; Staff I.B. at 71. The proposal is unexplained and unsupported.

any payment to the customer would unjustly enrich CECo and should not be permitted, according to MS. MS I.B. at 172-173. Michigan Systems explain that CECo has been receiving "free energy" from its customers and has refused to return the inadvertent energy upon the customer s request. Id. at 173; see Ex. MS-1 at 27; Ex. MS-4.

Michigan Systems also argue that CECo s proposal is discriminatory because when CECo over-delivers to other control areas, it is entitled to return of the energy in-kind. MS I.B. at 173. According to Michigan Systems, this would place CECo s customers at a competitive disadvantage. Id.

Michigan Systems argue that reimbursement at a rate of 90 percent of CECo s incremental cost makes sense because penalties for over-deliveries and under-deliveries should be symmetrical. Id. Michigan Systems claim that the customer should be reimbursed for negative energy imbalance at 90 percent of cost because the positive energy imbalance is based on a 110 percent of incremental cost. Id. at 174. This rate would encourage proper scheduling, as the customers would have no incentive to lean towards over-scheduling or under-scheduling. Id. at 173-174.

Ruling on Energy Imbalance Service - Payment of Accumulated Energy Imbalance Owed to Customer:

In light of the evidence presented, I find that the proposed payment of 90 percent of CECo's decremental cost, advocated by Staff, ABATE and City of Holland, has been justified for over-supply of energy within and outside the deviation band. CECo failed to present persuasive evidence that paying only 75 percent of CECo's decremental cost would be just and reasonable for over-supplied energy within the deviation band and that no payment should be made for over-deliveries outside the band. As Staff and allied parties argue, a 10 percent penalty applied to decremental cost for over-supply is symmetrical to the 10 percent penalty for under-supply adopted above. Moreover, the evidence indicates that other utilities compensate for over-supplies at 90 percent of decremental cost. Tr. at 1343. CECo's proposal, on the other hand, lacks evidentiary support, is inconsistent with the practices of other utilities and lacks intuitive merit.

ISSUE 8 C -- Energy Imbalance Service - Period for Return In-Kind

CECo proposes a tariff provision that would permit in-kind payments for energy imbalances within the deviation band to be made within the period of the transmission service transaction or the applicable monthly billing period covering the period of the transmission service. CECo I.B. at 84. Staff argues that the transmission customers should have at least 30 days after receiving notice of an imbalance for returning energy in-kind. Staff I.B. at 73.

Michigan Systems contend that CECo should allow a customer to return energy in-kind within the month following the billing month, but in all cases at least 20 days from receiving notice of an imbalance. MS I.B. at 174. It asserts that the additional 20 days would present CECo's customers with a reasonable opportunity to return energy in kind. Id. at 174-5. Michigan Systems claim that CECo's provisions are "unnecessarily restrictive," especially in the case where the imbalance occurs during the last few days of the month. Id. at 174. The problem arises because CECo usually prepares the bill after the end of the billing month, and, according to MS, the customer does not have adequate information regarding imbalances until it receives the monthly billing from CECo. Id. This in turn may be too late to return energy in-kind, MS claims. Id.

City of Holland introduces a slightly different proposal that in-kind energy replacement should be made "within 30 days of the later of (a) the end of the billing period, or (b) the date [CECo] notifies the customer that an imbalance has occurred." Holland I.B. at 18. City of Holland argues that its proposal is consistent with Order No. 888, which requires a 30-day in-kind reimbursement period for energy imbalances. Id., citing Order No. 888 at 31,961; see also MS R.B. at 55, citing Order No. 888 at 30,229.

Moreover, City of Holland claims that "[t]he elimination of the pro forma tariff's in-kind return option is not appropriate." Id. at 18-19, quoting Allegheny Power Systems, Inc., et. al., 80 FERC • 61,143 at 61,544 (1997). Michigan Systems point out that CECo fails to claim that reducing the period for in-kind returns is justified by the Commission's alternative standard of a "reasonable period generally accepted in the region." MS R.B. at 55. Additionally, Michigan Systems argue that CECo's proposal violates the Commission's comparability standard, as CECo itself is not subject to such returns in-kind within a specified period. Id.

CECo contends that Staff, Michigan Systems and City of Holland's assumption that the customer cannot detect the existence of an imbalance until it receives the monthly bill is unfounded. CECo I.B. at 84. On redirect, CECo witness Waits explained that the customers do not need to wait for the monthly bills, but that they can obtain such information from CECo on an ongoing basis virtually minutes after the end of each hour. Id. at 86.

CECo witness Waits explained that the accumulating meter data provided to MCCP is read on an hourly basis in the same way that the accumulating meters with other control areas are read.

Tr. at 1356. Mr. Waits continued by saying that the data from these accumulating meters, subject to telemetry corrections, is used to calculate MCCP's energy imbalance. Id. at 1356-57. In his opinion, "these telemetered values will be reasonably close to the month-end values that are used for official determination." Id. at 1138. Mr. Waits acknowledged that the telemetered values can only be retrieved from CECo's meters, but that certain added technology would permit the transmission customers to read these meters on an hourly basis. Id. at 1138-1141. Mr. Waits recognized that this necessary equipment is not currently in place, but believed that it could be installed in the future. Id. at 1141.

Although not rejecting the feasibility of CECo's alternative mechanism, Michigan Systems rebut this assertion by pointing out that the record fails to support CECo's commitment to it. MS I.B. at 175. It also argues that even if this data could be obtained from CECo's meters, the transmission customer may have to invest substantially in the necessary equipment and software to use such data. MS R.B. at 56. Staff also argues that there is no indication that this data from accumulating meters is provided to all transmission customers. Staff R.B. at 53. Moreover, Staff points out that this data is subject to later correction. Id.

In reply, CECo states that it can now confirm the energy imbalance data to which Mr. Waits testified is actually available to any customer who installs the necessary facilities to receive that information and that CECo will continue to make this information available if their proposal is adopted. CECo R.B. at 105. However, the record does not specify in any detail what the necessary facilities are or who will absorb the cost of these facilities.

Ruling on Energy Imbalance Service - Period for Return In-Kind:

CECo's proposal to require that in-kind payments for energy imbalances within the deviation band be made within the period of the transmission transaction or applicable monthly billing period covering the period of the transaction is troubling because customers are not able to know that an accumulated imbalance exists until they receive the monthly bill from CECo. CECo's response, that additional technology improvements (presumably made at the customers' expense) can make this information available to customers at an earlier time (See Tr. at 1138-41), and that MS entities could receive some information from which they can determine imbalances at an earlier time (See Tr. at 1354) is not sufficient to overcome the inequity of its proposal, particularly as applied to customers who do not receive anything close to real-time information as to imbalances. I cannot find it just and reasonable to require that imbalances be returned in-kind within the period of or the billing period for the transmission transaction when the exact status of imbalances is not known by those customers until later in time. It is far more reasonable, at least until real-time information is available to all of CECo's transmission customers, to follow the MS proposal that customers at least be given 20 days from the date that CECo notifies the customer of the imbalance to schedule the return in-kind. See Ex. MS-16 at 66.

ISSUE 8 D -- Energy Imbalance Service - On-Peak Energy Charge for Energy Not Returned In-Kind

CECo and Staff propose a charge for on-peak energy imbalances within the deviation band which are not returned in-kind at a rate of the greater of (1) 110 percent of actual replacement cost or (2) $0.10 per kWh (the same as $100/MWh). CECo I.B. at 86; Staff I.B. at 74; see Ex. CE-22 at Sheet Nos. 115. Staff argues that the $100/MWh energy charge acts as a mischeduling penalty and thus does not have to be cost based as long as it is reasonable. Staff I.B. at 74. Staff explains that since the energy imbalance would be within the band deviation, the transmission customer may avoid the charge by repaying the energy in-kind. Id.

ABATE and the City of Holland disagree with this proposal and argue that the charge for energy imbalances within the deviation band should be limited to 110 percent of the actual replacement cost. ABATE I.B. at 23; Holland I.B. at 16. ABATE believes that although the proposed $100/MWh rate may be reasonable for deviations outside the band, customers should not be penalized in the same manner through an artificial floor for imbalances within the band, as they are abiding by good utility practices. ABATE I.B. at 23. ABATE argues that there should be a clear distinction between imbalances within and outside the deviation band. Id. City of Holland explains that the point of having a deviation band in the first place is to provide some leeway within which the transmission customer will not be penalized for minor deviations between its scheduled and actual load. Holland I.B. at 16.

ABATE witness Dauphinais asserted that CECo's proposal is anti-competitive and could allow CECo to retain market power over its current customers. Ex. ABATE-1 at 31. Mr. Dauphinais stated that the rate should be based on the actual cost, rather than on an arbitrary charge of $50/MWh or $100/MWh. Id. In his view, charging 10 percent above avoided costs for energy owed to CECo and crediting customers 90 percent of actual avoided costs is fair and reasonable. Id. at 32. City of Holland contends that no reasonable transmission customer would conduct its transactions at 10 percent above cost. Holland I.B. at 16.

In reply, CECo argues that ABATE fails to offer any persuasive reason why this "commonly accepted charge" of $100/MWh is not appropriate. CECo I.B. at 87. In support, CECo refers to Staff witness Oxendine's testimony that "CECo charges the higher of $100/MWh (the same as $0.10/kWh) or out-of-pocket cost plus 10% for emergency service in its interconnection agreement with neighboring utilities." Id., citing Ex. S-1 at 17. Staff asserts that Mr. Dauphinais' recommendation does not necessarily act as a disincentive. Staff I.B. at 74. Staff explains that the transmission customer may find it beneficial to lean on CECo's system in the situation where its cost of generation is higher than CECo's actual replacement cost. Id. Staff further argues that ABATE fails to show how CECo may retain market power over its customers if its proposal is implemented. Staff R.B. at 53-54. Lastly, Staff asserts that if the 110 percent charge causes customers to repay in-kind, as ABATE and City of Holland contend, then the transmission customers will never be in the position of having to pay the $100/MWh charge. Id. at 54.

Ruling on Energy Imbalance Service - On-Peak Energy Charge for Energy Not Returned In-Kind:

This proposed charge of the greater of 110 percent of incremental cost or $100/MWh is for on-peak energy imbalances within the deviation band. To recall, on-peak energy imbalances outside the deviation band would carry a charge equal to the greater of 110 percent of incremental costs or $100/MWh, which is identical to the CECo/Staff proposal here for on-peak energy imbalances inside the deviation band. However, it appears desirable to structure this charge differently from the charge for on-peak energy imbalances outside the deviation band, in order that the totality of the rate design makes sense. If the charges are the same, there would appear to be no reason for a distinction between imbalances inside and outside the deviation band or a need for a deviation band. CECo, of course, accomplishes a desired holistic consistency by proposing capacity charges for imbalances outside the deviation band. That proposal having been rejected, we must now look at alternatives offered by ABATE and City of Holland to the proposed charges for on-peak imbalances within the band to determine if a desired consistency of structure can reasonably be obtained from the information in this record.

As argued by City of Holland, the point of a deviation band is to provide some leeway for minor deviations between scheduled and delivered loads that are unintended and should be relatively penalty-free. Holland I.B. at 16. ABATE persuasively maintains that, if customers are operating within the deviation band, they are adhering to good utility practice and should not be penalized through an artificial floor for imbalance pricing. ABATE I.B. at 23. While Staff and CECo are correct in their arguments that ABATE, which also claims CECo's proposal is anti-competitive, has failed to demonstrate that particular point, neither have CECo or Staff shown why a penalty greater than 110 percent of the incremental energy cost should be levied where the customers are adhering to good utility practice in operating within a pre-determined acceptable range. It is not enough to say that the proposed rate structure is followed by other utilities. Here, the argument has been raised that CECo's "greater of" rate proposal would be unreasonable, in light of the rate proposed (and adopted above) for energy imbalances outside the deviation band. Moreover, the whole rate design for energy imbalance service cries out for a distinction between "penalties" for operating within and outside the deviation band. That can be achieved by limiting the penalty for unreturned on-peak energy imbalances to 110 percent of incremental costs, i.e., by removing the feature of CECo's proposal that would charge customers the greater of 110 percent of incremental costs or $100/MWh.

I conclude that the most reasonable and just proposal for this service, in the context of other issues decided above, is to adopt the City of Holland/ABATE proposal that would charge customers who do not return on-peak energy imbalances within the allowed time frame 110 percent of system incremental cost.

Issue 8 E -- Application of Energy Imbalance to Customers Following Load

Michigan Systems and the City of Holland argue that they are control areas and thus any unscheduled energy deliveries should be treated as inadvertent energy exchanges and returned in-kind, and not subject to Energy Imbalance Service or Unauthorized Use charges. MS I.B. at 175; Holland I.B. at 19. On the other hand, CECo asserts that a transmission customer that follows load in CECo's control area should be subject to Energy Imbalance Service and Unauthorized Use charges. CECo I.B. at 87-89.

Michigan Systems, City of Holland and Staff agree that various factors that cause the inadvertent interchanges are outside the transmission customer's control. MS I.B. at 179; Holland at 19; Staff I.B. at 75. Inadvertent flows inevitably occur due to the inherent physics of the physical grid. Holland I.B. at 19; see Tr. at 1337. Michigan Systems' witness Cooper defined the inadvertent energy exchanges as "the methods by which interconnected utilities correct for any unscheduled and unintended transfer of energy from one utility to another." Ex. MS-1 at 11. Mr. Cooper recognized the principal causes of inadvertent interchanges as: forced outages or derates of generating units, metering and telemetry errors, generation response lag, and error dispatch. Id. He testified that often it is impossible to determine which utility caused the inadvertent energy exchange. Id.

Michigan Systems claim that the inadvertent energy method has been successfully used for several years under CECo's previous transmission tariff and Coordinated Operating Agreement ("COA") with MCCP, and should continue to be treated in this manner. MS I.B. at 176. Because CECo was the one that unilaterally proposed the inadvertent energy exchanges in 1992, Michigan Systems urge that CECo should not be allowed to reasonably argue against them at the present time. Id.

CECo unilaterally terminated the COA in 1996, and replaced it with an entirely new Network Operating Agreement ("NOA"), which introduced the Energy Imbalance and Unauthorized Use charges. Ex. MS-1 at 2. Michigan Systems argue that the MCCP has responsibly performed from 1992-1996 by controlling inadvertent interchanges through the COAs and that the imposition of the new higher charges do not create incentives to control inadvertent interchanges, but rather act as an excessive penalty. MS I.B. at 183.

Michigan Systems explained that the MCCP operates as a control area. MS I.B. at 176-177. Michigan Systems' witness Cooper described a control area as an entity that: (1) meters its load and all interconnections, (2) has sufficient capacity to meet its own load plus a prudent level of planning reserves, (3) provides telemetry, communications equipment/arrangements that allow information to be exchanged with the entity's dispatch center on a near-real-time basis, (4) has an adequate amount of generation under AGC to be able to regulate its loads, (5) uses a form of Energy Management System to balance the output of the entity's power supply resources to the entity's loads plus applicable transmission losses, and (6) maintains sufficient spinning and operating reserves to absorb the effects of unanticipated load swings and reasonable levels of forced generation or transmission outages without endangering reliability. Ex. MS-1 at 9.

CECO and Staff claim that neither Michigan Systems nor City of Holland qualify as control areas. CECo I.B. at 87-88; Staff I.B. at 75. CECo witness Waits argued that the MCCP is not a control area recognized by NERC. Ex. CE-68 at 1-6. Mr. Waits contended that Mr. Cooper's definition of a control area lacks certain requirements such as generation that has governors allowed to respond properly to interconnection frequency changes or tie-line bias control. Id. at 2. Moreover, Mr. Waits argued that even if the MCCP would become certified by NERC at a future time, it should not be excused from energy imbalance service because they are in a position to control the flows of power between them and CECo. Id. at 4. City of Holland's witness Howard stated on cross examination that the City of Holland has the ability to control energy imbalances and that it is not a NERC-recognized control area. Tr. at 1336-38.

Similarly, Mr. Cooper acknowledged that the MCCP is not a NERC-recognized control area, but argued that this fact is irrelevant because the MCCP meets the criteria of a control area. Id. at 9-10. Mr. Cooper focused on the fact that CECo itself is not a NERC-recognized control area, but merely part of the MECS, which is recognized as a control area by NERC. Id. at 10. He further noted that the former COA operating provisions were at least as restrictive as the NERC operating guidelines and that the present NOA operating requirements are in fact more restrictive than NERC's requirements. Id.

City of Holland similarly argues that it currently follows and historically has followed, load in its service area although it has been part of CECo's larger control area. Holland I.B. at 19. City of Holland asserts it should be recognized as a de-facto control area and that the mismatches between actual and scheduled load should be treated as inadvertent energy and returned in-kind. Id. at 20. It explained that from 1981 to August 1997, City of Holland and CECo have also operated under a COA, which classified these mismatches as inadvertent energy. Id. City of Holland contends that this treatment should be continued as no operating problems or threats to system integrity have been identified. Id. CECo witness Waits confirmed that he is not aware of any physical modifications to the interconnection between City of Holland and CECo which necessitated this change. Id. at 21.

In reply, CECo states that the former inadvertent energy provisions in the COAs are no longer appropriate under Order 888 for those parties who use the tariff to serve load within CECo's control area. CECo I.B. at 88-9. Mr. Waits testified that by changing the inadvertent energy provisions in the COAs, CECo acted consistently with Order No. 888 because "Energy Imbalance Service and Regulation and Frequency Response Service are together designed to comprehensively address the problem of mismatches between a customer's scheduled and actual deliveries of power." Ex. CE-1 at 11. Michigan Systems rebut this argument by pointing to the successful operating experience under the COAs. MS R.B. at 58.

Furthermore, Michigan Systems argue that penalizing the utility for inadvertent energy exchanges by labeling them as energy imbalances has been detrimental to its operations and is unjustified. MS I.B. at 177. According to Mr. Cooper, the MCCP was forced to implement less efficient operating strategy in order to avoid the Energy Imbalance charges. Ex. MS-1 at 14. CECo's proposed penalties create strong incentives for MCCP to generate more energy than it needs in order to avoid the "greater evil" of Unauthorized Use charges and thus incurs the "lesser evil" of providing free energy to CECo. MS I.B. at 178. Michigan Systems argue that they would prefer to target their inadvertent energy exchanges at zero, but they have been unable to do so since the Energy Imbalance and Unauthorized Use charges were implemented. Id. at 178-179; see Ex. MS-2.

Additionally, Michigan Systems and City of Holland argue that these charges are discriminatory. MS I.B. at 179; Holland I.B. at 22. They contend that CECO's charges are discriminatory because the operations of the MCCP and those of the City of Holland and are essentially the same as those of the MECS, yet CECo has not eliminated the inadvertent energy exchanges with MECS. Id. Neither MECS nor any other control area has been able to completely avoid inadvertent interchange.

On cross-examination, CECo's witness Waits testified that CECo has continued the inadvertent energy agreements with other entities such as Detroit Edison, Ontario Hydro, Toledo Edison, American Electric Power, and Northern Indiana Public Service. Tr. at 1101. Michigan Systems claim that CECo's refusal to reinstate inadvertent energy exchange provisions with the MCCP violates the Commissions's requirement that transmission customers be treated on a comparable basis to the transmission provider itself. MS I.B. at 182, citing Order 888 No. at 31,703.

Staff argues that many of Michigan Systems and City of Holland's problems can be cured by eliminating CECo's penalty provisions, implementing the deviation bandwidth, requiring CECo to provide notice of imbalances sooner, and permitting a period of 30 days for returns in-kind. Staff I.B. at 75. Staff contends that CECo's treatment of mismatches between schedule and load as energy imbalances are consistent with Order No. 888, but that mismatches between generation and load are not covered under the Energy Imbalance Service provision. Staff R.B. at 55, citing Order No. 888-A at 30,230.

City of Holland further contends that Staff's proposed modifications, although warranted, do not extend far enough to address the actual physical operations of the utilities. Holland I.B. at 10-11. Mr. Cooper recommended that inadevertent energy exchanges should be reinstated for MCCP in order to achieve comparability. MS I.B. at 183; see Ex. MS-1 at 31-33. Michigan Systems argue that elimination of the capacity charges alone will not fix the comparability problem because MCCP would remain subject to excessive charges for energy, confiscation of energy delivered to CECo, and other costs and burdens that neither CECo nor the MECS control area have to bear. MS I.B. at 183.

Ruling on Application of Energy Imbalance to Customers Following Load:

Many of the problems associated with CECo's proposal not to offer MCCP reinstatement of "in-kind" return of inadvertent energy imbalances are cured by the rulings on related issues above dealing with the proposed capacity charge penalty and rate issues for Energy Imbalance Service. However, as argued by City of Holland and MS, there remains the issue whether MCCP is nevertheless entitled to comparable treatment to other control areas interconnected to CECo.

Factors favoring MS and City of Holland's position include: (1) MCCP and the City of Holland operate as control areas, even though not recognized as such by NERC (See Exs. MS-1 at 8-10; H-1 at 13); (2) the predecessor operating agreements and tariff provided for "in-kind" return of inadvertent energy exchanges and operated successfully; (3) substitution of Energy Imbalance Service charges has resulted in operational inefficiencies, including the provision of free energy to CECO, in attempting to avoid onerous penalties (See Ex. MS-2); and (4) CECo interchanges with utilities and MECS are governed by inadvertent exchange arrangements.

On the other hand, CECo's proposal is supported by the following arguments: (1) neither MCCP nor City of Holland is a NERC-recognized control area; (2) Order No. 888 does not require retention of operating agreements offering "in-kind" return for inadvertent energy exchanges; (3) MS and Holland are able to control the flows of power between them and CECo; (4) opportunities may exist enabling transmission customers to "game" exchanges so that lower cost energy replaces higher cost energy; and (5) Order No. 888 provides a comprehensive regime to address the problem of mismatches between a customer's scheduled and actual deliveries of power, relying on Energy Imbalance Service charges.

Whether or not MCCP or Holland are NERC-certified control areas seems beside the point, recognizing that MECS itself is not a NERC-certified control area. The important consideration is that these entities operate like control areas. The predecessor agreements similarly seem beside the point because the Commission embarked upon a fundamentally new open access transmission market structure when it adopted Order No. 888 and its progeny.

The more important considerations are the arguments surrounding comparability, inefficiencies and potential gaming. Turning first to the latter point, I am persuaded that the gaming issue is not a significant concern. Experience under the pre-existing system has been that gaming was not a problem. While one can posit that, under a new competitive regime, opportunities might arise and be seized upon to manipulate exchanges to one's advantage, the Commission's complaint procedures are available to deal with such occurrences if they do arise. As to comparability, it seems fundamentally unfair that CECo offers "in-kind" return for inadvertent energy exchanges to MECS and other utilities, but will not do likewise for MCCP. That the Energy Imbalance Service penalty regime has forced ineffiencies on MCCP's operations because of the unavailability of a comparable service from CECo, provides good reason to question CECo's premise that Energy Imbalance Service is the only way to handle the mismatch problems with its customers. I conclude that CECo has not demonstrated that its proposal to require Energy Imbalance Service for its customers that follow load, like MCCP and the City of Holland, is just and reasonable.

ISSUE 8 F -- Energy Imbalance Service - Forced Generation Outages

CECo would apply the Energy Imbalance Service provisions of its OATT to energy shortfalls triggered by a loss of customer generation. CECo I.B. at 89. CECo contends that a forced outage at a customer's local generator behind the transmission provider's metering facilities that is not promptly covered will appear as a mismatch between scheduled deliveries and actual load. Given that the information as to the source of the problem is known only to the customer, CECo claims that a "no fault" concept should be applied by administering Energy Imbalance Service charges in such situations. To do otherwise, CECo contends, would require it to undertake "detective work" to determine if the mismatch between scheduled deliveries and load was caused by a forced generator outage, as opposed to many other possible contributing factors. Id. at 91.

MS argues that Energy Imbalance Service and the charges for exceeding the deviation band are intended to encourage good scheduling practice on the part of transmission customers to meet load variations. See Order No. 888-A at 30,232. Accordingly, MS contends, Energy Imbalance Service should only apply when the difference between scheduled deliveries and actual deliveries under the OATT can be remedied by good scheduling practice. It should not apply, MS maintains, if good scheduling practice could not have avoided the difference between scheduled and actual deliveries, such as when a generator forced outage caused the imbalance. MS I.B. at 185.

MS further points to the testimony of CECo witness Rasmussen, where he agreed that it was his understanding of Order Nos. 888 and 888-A that the occurrence of a mismatch between generation resources and load due to a failure of a generator to respond would not trigger Energy Imbalance Service obligations. Tr. at 790-91. While Mr. Rasmussen later indicated that CECo would treat such a shortfall as being subject to Energy Imbalance Service, MS contends that such a result is inconsistent with Order No. 888-A. MS I.B. at 185.

Staff agrees with MS that CECo would violate the policies expressed in the Order No. 888 series of orders if it applies Energy Imbalance charges to situations involving generator outages. Staff calls attention to the following language in Order No. 888-B at 62,092: "if the emergency is the cause of the customer's energy imbalance, that is, the transmission provider is unable to deliver the scheduled energy, the customer should not be responsible for paying an Energy Imbalance Service penalty." Staff further cites Order No. 888-A at 30,233: "we believe that emergency situations caused by loss or failure of facilities should be addressed in the transmission customer's service agreement (or the generation supplier's separate interconnection agreement) and not as part of Energy Imbalance Service."

CECo responds that the cited provisions were intended by the Commission to cover a specific situation related to remote generation located in a separate control area from the transmission customer and were not intended to apply to the facts presented here by MS. CECo continues to argue that its inability to monitor "behind the meter" local generation to distinguish generation failures from other events causing imbalances is critical and requires a "no fault" type solution. MS responds that CECo's "no fault" solution is in reality an "absolute liability" standard that would trigger Energy Imbalance Service charges regardless of cause, which is contrary to the guidance contained in the Order No. 888 series of orders.

Ruling on Energy Imbalance Service - Forced Generation Outages:

It seems clear that the Commission did not intend that imbalances created by forced generation outages be subject to Energy Imbalance Service penalty charges. Order No. 888-A at 30,233; Order No. 888-B at 62,092; Tr. at 790-91. CECo's protest, that these determinations were limited to the factual situation addressed and that the instant facts are not in accord, is unpersuasive. The Commission's language is clear, and the policy implications apparent. In addition, MS is correct that CECo's proposal is an absolute liability standard for imbalances, so that a penalty would apply, regardless of cause. Not only would that proposal do violence to the Commission's policy announced in Order No. 888 and related subsequent orders, but it would be per se unjust and unreasonable. Moreover, the practical constraints which concern CECo seem capable of resolution through normal communications channels. Detective work should not be required to ascertain whether or not an outage has in fact occurred. For these reasons, CECo's proposal is rejected.

ISSUE 9 A -- Spinning Reserve Service - Revenue Requirement

ISSUE 9 B -- Spinning Reserve Service - Unit Rate Calculation

ISSUE 9 C -- Spinning Reserve Service - Purchase Obligation

The Company's proposed annual revenue requirement, unit rate calculation and purchase obligation for Spinning Reserve Service are set forth in Ex. CE-17 at 21-22. CECo proposes a revenue requirement of $712,605,000, an allocation factor of 1.65 percent, resulting in a monthly unit rate of $0.17/kW, and a purchase obligation of 1.50 percent of the customer's reserve capacity or network load. Staff proposes a slightly higher monthly rate of $0.19/kW because Staff uses the 1.69 percent allocation factor for Spinning Reserve Service, while CECo uses 1.65 percent. Staff also proposes a 1.69 percent customer purchase obligation for Spinning Reserve Service.

MS contends that a 1-CP denominator should be employed to calculate this rate and that Appalachian pricing should not be used to calculate short-term pricing.

Ruling on Spinning Reserve Service Issues:

The ruling on this issue is governed by issues previously decided. The revenue requirement will be determined on the basis of rulings made previously that affect that determination. The unit rate calculation proposed by Staff will be accepted as just and reasonable. The allocation factor proposed by Staff is the remainder of the 3.0 percent ECAR reserve requirement after deleting the 1.31 percent factor for Regulation and Frequency Response Service. Ex. S-8 at 13; see also Issue 7 above. For the reasons noted in the ruling on Regulation and Frequency Response Service, Staff's approach is preferable to the arbitrary allocation preformed by CECO. For the same reason, Staff's proposal for a customer service obligation of 1.69 percent will be accepted over the CECo alternative of 1.50 percent. 35/

ISSUE 10 A -- Supplemental Reserve Service - Revenue Requirement

ISSUE 10 B -- Supplemental Reserve Service - Unit Rate Calculation

ISSUE 10 C -- Supplemental Reserve Service - Purchase Obligation

CECo proposes to base the rate for Supplemental Reserve Service on a revenue requirement of $712,605,000, which includes all generation, except nuclear. Ex. CE-17 at 22. Staff, on the other hand, proposes a revenue requirement for this service of only $6,967,821, which includes only CECo's combustion turbine peaking units. See Ex. S-36.

CECo argues that Staff's proposal is based upon Staff witness Smith's "cryptic assumption that only CECo's combustion turbine

35/ Staff's also correct that, under the provisions of Order No. 888 at 31,961, CECo should set forth in its tariff the customer purchase obligation percentage. Staff I.B. at 78.

generating units should be allocated to this service". CECo I.B. at 95. CECo witness Waits testified that all of CECo's dispatchable generation is capable of supplying operating reserves and that 50 percent of its operating reserves should be assigned to Supplemental Reserve Service. Exs. CE-68 at 8-10; CE-17 at 15. He argued that Staff witness Smith's definition of CECo units allocable to this function is far too restrictive. Mr. Waits also argued that, while combustion turbines are the least costly units to install from the standpoint of capital cost, they carry the highest fuel cost when operating. Ex. CE-68 at 9. Since fuel costs are not included in the revenue requirement for this service, Mr. Waits contended that Staff's proposal to base the rate only on combustion turbine investment would vastly understate the true cost of providing that service from combustion turbines. Id. CECo further observes that the Staff-proposed rate is far below rates for this service advocated by Staff in Northern Indiana Public Service Co., 79 FERC • 63,009 at 65,117 (1997).

Staff responds that it based its proposed rates for this service on the costs of the particular units used to provide the service at issue for this particular utility. This explains why its position in other cases may have been quite different. Staff R.B. at 57. Staff further claims that its rate proposal here is not out of line with rates for similar services proposed by other utilities in Open Access Transmission Tariffs, such as that of IES Services, Inc., where that company proposed a $0.04/kW monthly charge for Supplemental Reserve Service. Allegheny Power System Inc., et al., 80 FERC • 61,143 at 61,541 (1997). Staff goes on to argue that the Commission defined supplemental reserve as capacity that can respond to a contingency situation, but that is usually available within ten minutes, rather than immediately. According to Staff, the Commission indicated, in Order No. 888 at 31,708, that these reserves are provided by generating units that are on-line, but unloaded, or by "quick-start" generation. CECo has not, argues Staff, shown that all of its generating units fall into the category of "on-line but unloaded." Staff claims to have met the Commission's definition by including only the units most likely to provide this service. Ex. S-8 at 16.

CECo proposes a monthly unit rate of $0.34/kW based upon an allocation factor of 3.3 percent. The equivalent monthly rate advocated by the Company is $10.30/kW ($0.34 divided by .033) Staff proposes a monthly charge of $1.29/kW, with an allocation factor of 3.0 percent and using the cost and associated capacity of only CECo's turbine generator units.

CECo proposes that the customer purchase obligation for this service should be 3.3 percent and Staff proposes that it be set at 3.0 percent. Staff also asks that CECo be instructed to include in its OATT, language that would allow the customer to determine the amount of this service that must be purchased. Staff I.B. at 80; see Ex. S-8 at 17-18.

Ruling on Supplemental Reserve Service Issues:

The supplemental service revenue requirement should be based upon the costs of units that are most likely to provide the service. Here, Staff has made a persuasive case for basing this rate on the Company's combustion turbine generating units as opposed to all of the Company's generation (except nuclear), as advocated by CECo. CECo has failed to show that basing this rate on every unit in its system is consistent either with rational pricing policy or the Commission's Order No. 888. Specifically, CECo has not demonstrated that all of its units fall into the category of plants "on-line, but unloaded" referred to by the Commission in Order No. 888 at 31,708. In such a circumstance, it would be erroneous to base a rate for supplemental service on the full range of CECo's generating resources. Accordingly, Staff's proposal is adopted. Neither is CECo's fuel cost argument persuasive. As Staff observes, fuel costs may be recovered as the units are used to produce energy. There is no real danger of cost underrecovery.

The unit rate and purchase obligation percentage should track Staff's proposals, as well. Further, Staff's proposal that CECo be required to add language to its tariff informing customers of the purchase obligation is also adopted as reasonable and necessary.

CONCLUSION

It is concluded that the just and reasonable rates and the tariff provisions affecting such rates are and will be those that are in conformity with the findings and conclusions set in this decision.

ORDER

IT IS ORDERED, subject to review by the Commission on exceptions or its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty days of the issuance of the Final Order of the Commission in this proceeding, Consumers Energy shall file revised tariff sheets in accordance with the findings and conclusions of this Initial Decision, as adopted or modified by the Commission.

William J. Cowan
Presiding Administrative Law Judge

Document Content(s)