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Issues: System Energy Losses

Witness: Erin L. Maloney
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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

ERIN L. MALONEY

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2006-0315

Jefferson City, Missouri
June 2006

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Company of Joplin, Missouri for authority to file tariffs increasing rates for electric service provided to customers in Missouri service area of the Company.)	Case No. ER-2006-0315

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Direct Testimony in question and answer form, consisting of 12 pages to be presented in the above case; that the answers in the foregoing Direct Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of her knowledge and belief.

Erin L. Maloney

Erin L. Maloney

Subscribed and sworn to before me this 22nd day of June 2006.

Dawn L. Hake

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

DAWN L. HAKE
My Commission Expires
March 16, 2009
Cole County
Commission #05407643

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Q. Please state your name and business address?

A. Erin L. Maloney, P.O. Box 360, Jefferson City, Missouri, 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as a Utility Engineering Specialist II in the Energy Department of the Utility Operations Division.

Q. Please describe your educational and work background.

A. I graduated from the University of Nevada - Las Vegas with a Bachelor of Science degree in Mechanical Engineering in June 1992. From August 1995 through November 2002, I was employed by Electronic Data Systems of Kansas City, Missouri, as a System Engineer. In January 2005, I joined the Commission Staff (Staff) as a Utility Engineering Specialist I.

Q. Have you previously filed testimony before the Commission?

A. Yes. I filed testimony on reliability in Case No. ER-2005-0436.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to recommend that the Commission adopt the system energy loss factor and the jurisdictional allocation factors for demand and energy that were calculated as shown on Schedules 1, 2, and 3 respectively, attached to this direct testimony. This testimony also describes how these factors were determined.

EXECUTIVE SUMMARY

Q. Please briefly summarize your testimony.

A. The system energy loss factor was calculated to be 6.98%.

The jurisdictional allocation factors for demand and energy have been calculated using a Twelve Coincident Peak (12 CP) methodology as follows:

	Missouri Retail	Non-Missouri Retail	Wholesale
Demand	0.8221	0.1149	0.0630
Energy	0.8256	0.1093	0.0651

SYSTEM ENERGY LOSS FACTOR

Q. What is the result of your system energy loss factor calculation?

A. As shown on Schedule 1, attached to this Direct Testimony, the calculated system energy loss factor is 0.0698.

Q. What are system energy losses?

A. System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) in Empire's system between the generating sources and the customers' meters. In addition, small, fractional amounts of energy either stolen (diversion) or not metered are included as system energy losses.

Q. How are system energy losses determined?

A. The basis for this calculation is that Net System Input (NSI) equals the sum of "Total Sales," "Company Use," and "System Energy Losses." This can be expressed mathematically as:

NSI = Total Sales + Company Use + System Energy Losses

NSI, Company Use and Total Sales are known; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales – Company Use

The system energy loss factor is the ratio of system energy losses to NSI:

System Energy Loss Factor = System Energy Losses ÷ NSI

Q. How is NSI determined?

A. In addition to the equation above, NSI is also equal to the sum of Empire's net generation, net interchange, and any inadvertent flows. Net interchange is the difference between interchange purchases and off-system sales. Net generation is the total energy output of each generating station minus the energy consumed internally to enable its production. The output of each generating station is monitored continuously, as is the net of off-system purchases and sales. This information was obtained from data supplied by Empire in response to Staff Data Request Nos. 119, 125, and 210. The difference between scheduled and actual flows on a system is termed inadvertent interchange. This information was provided on a monthly basis in Empire's response to Staff Data Request 210.

Q. What are Total Sales and Company Use and how are these values determined?

A. Total Sales includes all of Empire's retail and wholesale sales of energy. Company Use is the electricity consumed at Empire's non-generation facilities, such as its corporate office building at 620 Joplin Street, Joplin, Missouri. Total Sales data was provided by Empire in response to Staff Data Request No. 206. Company Use data was provided by Empire in response to Staff Data Request Nos. 206 and 207.

Q. Which Staff witness used your calculated system energy loss factor?

A. The system energy loss factor was used by Staff witness Shawn E. Lange.

JURISDICTIONAL ALLOCATIONS

Q. Please define the phrase "jurisdictional allocation".

A. For purposes of this testimony, jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri retail operations, non-Missouri retail operations and wholesale operations. The particular allocation factor applied is dependent upon the types of costs being allocated.

DEMAND ALLOCATION FACTOR

Q. What are the demand allocation factors that you are recommending be used in this case?

A. As shown on Schedule 2 attached to this direct testimony, the calculated demand allocation factors for the test year are as follows:

Missouri Retail	0.8221
Non-Missouri Retail	0.1149
Wholesale	0.0630

Q. What is the definition of demand?

A. Demand refers to the rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), either at an instant in time or averaged over any designated interval of time. In this analysis, hourly demands were used.

Q. What types of costs are allocated on the basis of demand?

A. Capital costs associated with generation and transmission plant and certain operational and maintenance expenses are allocated on this basis. This is appropriate for these expenditures because generation and transmission are planned, designed and constructed to meet anticipated demand.

Q. What methodology was used to determine the demand allocators?

A. A methodology known as the Twelve Coincident Peak (12 CP) methodology was used.

Q. What is meant by the twelve coincident peak methodology?

A. The term coincident peak refers to the load of each jurisdiction that coincides with the hour of Empire's overall system peak. A 12 CP methodology refers to utilizing the recorded peaks in each of the twelve (12) months of the selected test year.

Q. Why use peak demand as the basis for allocations?

A. Peak demand is the largest electric load requirement occurring on a utility's system within a specified period of time (e.g., day, month, season, year). Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.

Q. Please describe the procedure for calculating the jurisdictional demand allocation factors using the 12 CP methodology.

A. The allocation factor for each jurisdiction was determined using the following process:

1. Empire's peak hourly monthly loads in calendar year 2005 were identified and summed.

2. Each jurisdiction's loads during Empire's monthly peak hours, identified in #1 above, were summed.

3. The sum for each jurisdiction calculated in #2 above was divided by the sum of Empire's 12 monthly peak loads (result of #1 above).

This resulted in the allocation factor for each jurisdiction. The sum of the demand allocation factors across all jurisdictions equals one.

Q. How was the decision made to recommend using the 12 CP method?

A. The 12 CP method is appropriate for a utility, such as Empire, that experiences relatively small variations in monthly and/or seasonal (e.g., summer and winter) peaks during a particular year. Schedule 4, attached to this Direct Testimony, presents a table of Empire's maximum hourly peak in each month for calendar years 2001 through 2005. This information was taken from the Federal Energy Regulatory Commission (FERC) Form 1, and data provided by the Company in response to Staff Data Request No. 130 in this case, and Staff Data Request No. 2921 in Case No. ER-2002-424. As shown, Empire experiences its system peak during the summer months (July, August, and September); however, the monthly peak hours occurring during the winter months (December and January) are relatively high due to the Company's high saturation of electric heat customers.

The line graph on Schedule 6 attached to this Direct Testimony presents, for each of the years 2001 through 2005, a plot of each month's peak hour as a percentage of:

a) The peak hour for the corresponding year; and

b) The average of the monthly peak hours for the corresponding year.

The graph, which was derived from the data shown in Schedule 4, indicates consistent peaks in both the summer and the winter across the time period.

Q. Is there additional support for the position that a 12 CP methodology is appropriate in this case?

A. Yes. In various cases, the FERC has, among other things, used a number of tests as a guide in its determination of an appropriate allocation methodology. These tests are arithmetical calculations whose results are compared to specific ranges determined from prior FERC decisions which suggest which methodology is more appropriate. Attached to this testimony as Schedule 5 is an excerpt (Chapter 5) from a publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers," Third Edition (1994), authored by Michael E. Small. As this excerpt shows, FERC has used these tests to support its adoption of a 12 CP methodology in a number of cases. On occasion, however, these tests have suggested that an alternative coincident peak methodology (such as a 4 CP) might be more appropriate.

Q. Please describe the tests you used in your selection of a CP methodology.

A. The following tests included in the aforementioned guidelines (attached as Schedule 5) were used:

Test 1 - Computes the difference between the following two percentages:

a) The average of the monthly system peaks during the reported peak period as a percentage of the annual peak, and

b) The average of the system peaks during the remainder of the test period as a percentage of the annual peak.

For calculated differences that fell between 18% and 19%, the FERC typically adopted a 12 CP methodology. For differences that fell between 26% and 31%, the FERC typically adopted a 4 CP methodology.

Test 2 - The average of the twelve monthly peaks in the reporting period as a percentage of the annual peak.

When the resulting percentage fell between 81% and 88%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 78% and 81%, the FERC typically adopted a 4 CP methodology.

Test 3 - The lowest monthly peak as a percentage of the annual peak.

When the resulting percentage fell between 66% and 81%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 55% and 60%, the FERC typically adopted a 4 CP methodology.

Q. Did you apply these FERC tests to Empire's data?

A. Yes. As illustrated on Schedule 7, the following percentages using the demands recorded for the twelve-month period ending December 31, 2005 were calculated:

Test 1 -	18.63%
Test 2 -	83.28%
Test 3 -	57.22%

Q. Please discuss the significance of these results.

A. The result of the first test (18.63%) falls within the above-indicated 18%-19% range of results that led to FERC decisions adopting a 12 CP methodology. Likewise, the result of the second test (83.28%) is within the 81%-88% range of results in FERC decisions adopting a 12 CP methodology. The result of the third test (57.22%) falls within the 55%-60% range for which the FERC issued decisions adopting a 4 CP methodology. Overall, these tests lend support for usage of the 12 CP methodology.

Q. Are there any other factors to consider in determining the appropriate allocation methodology?

A. Yes. These FERC tests are part of a larger set of factors historically utilized by the FERC in its determination of which coincident peak methodology should be used in electric utility cases. In a rate case decision involving Carolina Power and Light Company[1], for example, the FERC states: "…it is necessary to consider the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments" (footnote omitted). In the adoption of the 12 CP methodology, FERC has cited these operating realities, all of which affect a utility's effective capacity, as important to its determination.

Q. How do these operational realities apply to Empire?

[1] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978).

A. There are periods of time, typically in the spring or fall, when the usage level of the Company's native load customers is reduced. At such times, the Company is able either to perform necessary maintenance on its power plants or to pursue off-system sales, while retaining sufficient capacity to adequately meet its customers' requirements. Furthermore, the Company's capacity planning process takes into account all the hours of the year, not just the peak hour or any seasonal peak. These operational realities, along with the test results and aforementioned analysis, provide ample evidence to support Staff's recommendation to adopt a 12 CP methodology in the current proceeding.

Q. Did the Company incorporate the 12 CP methodology in its filing of this rate case?

A. Yes.

Q. Which Staff witness used your jurisdictional demand allocation factors?

A. I provided these jurisdictional demand allocation factors to Staff witness Dana E. Eaves.

ENERGY ALLOCATION FACTOR

Q. What energy allocation factors are you recommending be used in this case?

A. The factors are shown in Schedule 3 and repeated here.

Missouri Retail	0.8256
Non-Missouri Retail	0.1093
Wholesale	0.0651

Q. What types of costs were allocated on the basis of energy?

A. Variable expenses, such as fuel and certain operational and maintenance (O&M) costs, are allocated to the jurisdictions based on energy consumption.

Q. How did you calculate the energy allocation factor?

A. The energy allocation factor for an individual jurisdiction is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total normalized Empire kWh usage. The sum of the energy allocation factors across jurisdictions equals one. The actual jurisdictional kWh usage totals were provided in the Company response to Staff Data Request No. 206.

Q. What adjustments were made to these recorded kWhs?

A. The Staff made the following adjustments to be consistent with the net system hourly loads used in determining normalized fuel costs:

a. Normalization Adjustment
b. Annualization Adjustment
c. Customer Growth Adjustment
d. Wholesale Weather Adjustment

Q. Did you calculate these adjustments?

A. No. Staff witness Shawn E. Lange supplied adjustments a., b., and d. Please refer to Mr. Lange's testimony for a summary of these adjustments. Staff witness Dana E. Eaves provided me with the customer growth adjustment. Please see Mr. Eaves's testimony for a further explanation of this adjustment.

Q. Which Staff witness used your jurisdictional energy allocation factors?

A. I provided these jurisdictional energy allocation factors to Staff witness Dana E. Eaves.

Q. Does this conclude your prepared Direct Testimony?

A. Yes, it does.

SYSTEM ENERGY LOSS PERCENTAGE

	Net Generation	Net Interchange	Inadvertant Flows	Net System Input	Retail Sales	Wholesale Sales	Company Use	Losses
Jan-05	359,432,000	105,872,000	(98,000)	465,206,000	405,500,151	26,648,420	1,037,012	32,020,417
Feb-05	278,342,000	109,559,000	239,000	388,140,000	336,988,002	23,256,760	877,762	27,017,476
Mar-05	288,439,000	118,832,000	(166,000)	407,105,000	352,501,296	25,414,260	849,487	28,339,957
Apr-05	245,128,000	102,738,000	6,000	347,872,000	299,568,077	23,273,720	720,648	24,309,555
May-05	274,438,000	116,001,000	(56,000)	390,383,000	336,579,672	25,725,760	772,383	27,305,185
Jun-05	377,077,000	96,711,000	(126,000)	473,662,000	409,239,536	30,378,300	851,798	33,192,366
Jul-05	432,826,000	91,543,000	171,000	524,540,000	454,675,874	32,229,500	831,267	36,803,359
Aug-05	460,055,000	86,612,000	(244,000)	546,423,000	473,283,050	33,959,380	895,157	38,285,413
Sep-05	355,965,000	106,694,000	445,000	463,104,000	400,252,282	29,601,960	887,215	32,362,543
Oct-05	274,833,000	117,786,000	(274,000)	392,345,000	338,347,423	25,762,040	812,931	27,422,606
Nov-05	275,285,000	124,429,000	40,000	399,754,000	346,440,259	24,606,480	752,649	27,954,612
Dec-05	340,430,000	154,143,000	(63,000)	494,510,000	431,044,071	27,946,280	974,978	34,544,671
Totals	3,962,250,000	1,330,920,000	(126,000)	5,293,044,000	4,584,419,693	328,802,860	10,263,287	369,558,160

System Energy Loss Percentage = (Losses / Net System Input) X 100% = 6.98%

DEMAND ALLOCATION FACTOR

Month	Missouri Retail	Non-Missouri Retail	Wholesale	Total System
Jan-05	747.7	99.8	52.5	900
Feb-05	680.5	90.4	49.1	820
Mar-05	679.9	88.5	49.6	818
Apr-05	508.9	70	43.1	622
May-05	666.8	98.4	54.8	820
Jun-05	844.2	120.3	68.5	1033
Jul-05	890.7	127.9	68.4	1087
Aug-05	850.2	129.3	70.5	1050
Sep-05	808.9	117	65.1	991
Oct-05	689	106.6	58.4	854
Nov-05	695.3	93	48.7	837
Dec-05	868.9	106.4	55.7	1031
Twelve Month Avg	8931	1247.6	684.4	10863
Allocation Factor	**0.8221**	**0.1149**	**0.0630**	**1.0000**

ENERGY ALLOCATION FACTOR

Month	Missouri Retail	Non-Missouri Retail	Wholesale	Total System
Jan-05	369,748,480	48,881,895	26,648,420	445,278,795
Feb-05	330,464,071	42,282,384	23,256,760	396,003,215
Mar-05	301,063,765	38,939,497	25,414,260	365,417,522
Apr-05	297,497,572	40,388,179	23,273,720	361,159,471
May-05	276,137,730	37,648,373	25,725,760	339,511,863
Jun-05	322,496,512	45,132,952	30,378,300	398,007,764
Jul-05	380,571,229	53,070,231	32,229,500	465,870,960
Aug-05	404,240,551	55,222,724	33,959,380	493,422,655
Sep-05	409,802,040	56,243,727	29,601,960	495,647,727
Oct-05	325,125,397	45,643,433	25,762,040	396,530,870
Nov-05	287,954,047	38,168,556	24,606,480	350,729,083
Dec-05	359,886,332	43,846,299	27,946,280	431,678,911
12 Month Totals	4,064,987,726	545,468,250	328,802,860	4,939,258,836
Normalization Adjustment	(17,993,790)	(5,246,325)		(23,240,115)
Annualization Adjustment	(7,576,451)	(1,542,899)		(9,119,350)
Customer Growth Adjustment	76,232,504	6,230,469		82,462,973
Wholesale Weather Adjustment			(4,075,784)	(4,075,784)
Adjusted 12 Month Totals	4,115,649,989	544,909,495	324,727,076	4,985,286,560
Allocation Factor	**0.8256**	**0.1093**	**0.0651**	**1.0000**

Monthly System Peaks (MW)

	2005	2004	2003	2002	2001
January	900	937	987	891	919
February	820	895	865	872	841
March	818	691	806	870	701
April	622	635	697	655	642
May	820	803	736	738	791
June	1033	911	927	897	859.3
July	1087	1010	1019	984	999
August	1050	1014	1041	987	1001
September	991	873	813	950	878
October	854	633	613	804	618
November	837	756	754	748	769
December	1031	913	849	820	764

Chapter Five—Functionalization, Classification, and Allocation

In allocating costs to a particular class of customers, there are three major steps (if all cost of service issues have been resolved): (1) functionalization, (2) classification, and (3) allocation. FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation. *See, e.g.*, *Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶61,222, p. 61,504 (1981); *Utah Power & Light Co.*, Opinion No. 113, 14 FERC ¶61,162, p. 61,298 (1981).[133]

A. Functionalization

Generally, plant or expense items are first functionalized into five major categories:

(1) Production;

(2) Transmission;

(3) Distribution;

(4) General and Intangible; and

(5) Common and Other.

See 18 C.F.R. §35.13(h)(4)(iii) (plant); 18 C.F.R. §35.13(h)(8)(i) (O&M expenses). Each plant or expense item will be segregated into the category with which it is most closely related.

While functionalization for most items is relatively straightforward, and not usually litigated, problems do arise with respect to the functionalization of administrative and general expenses (A&G)[134] and general plant expenses.[135] FERC stated that:

> The Commission normally requires that A&G and General Plant expenses be allocated on the basis of total company labor ratios. Under such allocation method, A&G and General Plant expense items are 'functionalized,' or segregated into...

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133 Where a company has significant non-jurisdictional business, the above cost incurrence principle is important in keeping FERC within its jurisdictional constraints. *See Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 641-42 (1945) ("the Commission must make a separation of the regulated and unregulated business... Otherwise the profits or losses... of the unregulated business would be assigned to the regulated business and the Commission would transgress the jurisdictional lines which Congress wrote into the Act").

134 A&G expenses include salaries of officers, executives, and office employees, employee benefits, insurance, etc.

135 General plant includes office furniture and equipment, transportation vehicles, lockers, tools, lab equipment, etc.

Schedule 5-1

> production, transmission, distribution, customer accounts, customer service, information, and sales. This "functionalization" is in proportion to the ratio of the labor cost in each major function to total labor costs less A&G and General Plant labor. Each functionalized component is allocated to customer groups.

Utah Power & Light Co., Opinion No. 308, 44 FERC ¶61,166, p. 61,549 (1988). *See also Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶61,116, p. 61,258 (1978) (general plant will be functionalized by labor ratios unless it is shown that the use of labor ratios produces unreasonable results). In many cases, FERC has allowed labor ratios to be used to functionalize general plant. *See, e.g., Utah Power & Light Co.*, Opinion No. 308, 44 FERC at 61,549; *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,034 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Delmarva Power & Light Co.*, 17 FERC ¶63,044, p. 65,204 (1981), *aff'd*, Opinion No. 185, 24 FERC ¶61,199 (1983); *Philadelphia Electric Co.*, 10 FERC ¶63,034, pp. 65,355-56, *aff'd*, 13 FERC ¶61,057 (1980). Similarly, FERC has required that most A&G expenses be functionalized on the basis of labor ratios. *Missouri Power & Light Co.*, Opinion No. 31, 5 FERC ¶61,086, pp. 61,137-38 (1978); *Kansas City Power & Light Co.*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204. An exception to this has been established for property insurance which has been functionalized on plant ratios. *Pacific Gas & Electric Co.*, 16 FERC ¶63,004, pp. 65,015-16 (1981), *aff'd*, Opinion No. 147, 20 FERC ¶61,349 (1982); *Kansas-Nebraska Natural Gas Co.*, Opinion No. 731, 53 FPC 1691, 1722 (1975).

Common plant and intangible plant also have been analogized to general plant and functionalized on the basis of labor ratios. *Kansas City Power & Light*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204; *Philadelphia Electric*, 10 FERC at 65,355-56.

Another issue that has arisen is the calculation of the labor ratios. Usually, the labor ratio consists of total labor costs in the denominator with the labor costs associated with a particular category in the numerator. In a number of proceedings, companies have attempted to change the ratio by only including production, transmission, and distribution-related labor costs in the denominator, thereby excluding customer service related labor costs. FERC rejected this in at least one case. *Kansas City Power & Light*, 21 FERC at 65,033-34.

B. Classification

After functionalizing, the next step is to classify those expenses or costs into one of three categories (1) demand, (2) energy, or (3) other. *See* 18 C.F.R. §35.13(h)(8)(ii)(A).

FERC's Staff for a number of years has used the predominance method for classifying production O&M accounts. Under this method if an account is *predominantly* (51-100%) energy-related, it will be classified as energy. The same also is true with respect to demand related costs. FERC has accepted this method in a number of cases. *See, e.g., Arizona Public Service Co.*, 4 FERC ¶61,101, pp. 61,209-10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,255-56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light*

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Co., 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648-49 (1980).[136]

In addition to FERC's adoption of Staff's predominance method, FERC also has adopted Staff's classification index of production O&M accounts. *Arizona Public Service Co.*, 4 FERC at 61,209-10; *Kansas City Power & Light*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648-49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by Staff, which has been approved by the Commission." In *Southern Company Services*, Opinion No. 377, 61 FERC ¶61,075, p. 61,314 (1992), *reh. denied*, 64 FERC ¶61,033 (1993), FERC, however, stated that the Staff index is not mandatory. FERC accepted a departure from the Staff's index, though it held that a party proposing a departure has the burden of justifying that departure.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak (CP) method. *Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) ("Maine Public has cited a legion of Commission decisions affirming the use of a coincident peak demand allocator.... And, it denies knowledge of '*any* decision, involving an electric utility since the FERC came into existence in 1977, where FERC did not follow a coincident peak method of allocating demand costs'."). In *Lockhart Power Co.*, 4 FERC ¶61,337, p. 61,807 (1978), FERC stated that its "general policy is to allocate demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092. Under a CP method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period. The basic assumption behind this method is that capacity costs are incurred to serve the peak needs of customers.

1. Coincident Peak Allocation

In most cases, FERC has accepted *one* of four CP methods—1 CP, 3 CP, 4 CP, and 12 CP, with the largest number of companies using a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12

136 If a company is able to justify a percentage split, such as 70-30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method likely will have the burden of justifying its proposed split.

Schedule 5-3

CP companies the numerator would consist of the average of the wholesale class coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. FERC has held that interruptible loads should not be reflected in this demand allocation.[137] *See Delmarva Power & Light Co.*, Opinion No. 189, 25 FERC at 61,121; *Delmarva Power & Light Co.*, Opinion No. 185, 24 FERC ¶61,199, p. 61,462 (1983).

While FERC has not established a hard and fast rule for determining which allocation method is appropriate, it has stated that the following factors should be considered:

> [T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. (footnote omitted).

Carolina Power & Light Co., Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978); *Commonwealth Edison Co.*, 15 FERC ¶63,048, p. 65,196 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,247-48 (1980), *aff'd*, 15 FERC ¶61,050 (1981). *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092 (applying FERC's various tests in finding that a 12 CP was appropriate).

a. System Demand Tests

If a utility's system demand curve is relatively flat, then that supports the use of a 12 CP method under FERC precedent. If a utility experiences a pronounced peak during one, three, or four consecutive months, then under FERC precedent the use of another CP method would be supported.

In determining whether a utility experiences a pronounced peak during a particular time period, FERC considers a number of tests. First, FERC has compared the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. FERC has held that large differences between these two figures lends support to using something other than a 12 CP method, while a smaller difference supports 12 CP as shown below.[138]

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(31% difference—4 CP);

[137] FERC ordered that the revenues from the interruptible loads be credited to the cost of service. *Delmarva Power & Light Co.*, 28 FERC ¶61,279, p. 61,510 (1984).

[138] *See also Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) (the ALJ stated that "using established Commission tests that compare average monthly peaks with the annual peak, lowest monthly peak to the annual peak, average monthly demand peaks of the peak season to the monthly demand peaks of the off-peak service" Maine Public is a 12 CP company).

(2) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(26% difference—4 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(18% difference—12 CP);

(4) *Illinois Power Co.*,
11 FERC at 65,248,
(19% difference—12 CP);

(5) *Commonwealth Edison Co.*,
15 FERC at 65,196
(16.4-24.9% differences—4 CP);

(6) *Southwestern Public Service Co.*,
18 FERC at 65,034
(average difference of 22.9%; high of 28.3%—3 CP).

FERC also has used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(56%—4 CP);

(2) *Idaho Power Co.*,
Opinion No. 13,
5 FERC ¶61,108 (1978)
(58%—3 CP);

(3) *Southwestern Electric Power Co.*,
Opinion No. 28,
4 FERC ¶61,330 (1978)
(55.8%—4 CP);

(4) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(73%—12 CP);

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(5) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(79%—12 CP);

(6) *Alabama Power Co.*,
Opinion No. 54,
8 FERC ¶61,083 (1979)
(75%—12 CP);

(7) *Illinois Power Co.*,
11 FERC at 65,248
(64%—12 CP);

(8) *Commonwealth Edison Co.*,
15 FERC at 65,198
(64.6-67.8%—4 CP);

(9) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(61.9%—4 CP);

(10) *El Paso Electric Co.*,
Opinion No. 109,
14 FERC ¶61,082 (1981)
(71%—12 CP);

(11) *Carolina Power & Light Co.*,
Opinion No. 19,
4 FERC ¶61,107 (1978)
(72%—12 CP);

(12) *New England Power Co.*,
Opinion No. 803,
58 FPC 2322 (1977)
(80%—12 CP);

(13) *Southwestern Public Service Co.*,
18 FERC at 65,034
(on average, almost 67 percent—3 CP); and

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(14) *Delmarva Power & Light Co.*,
17 FERC at 65,201
(71.4%—12 CP).

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four year period, a peak in one of the 4 peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*,
11 FERC at 65,248-49
(81%—12 CP);

(2) *El Paso Electric Co.*,
Opinion No. 109,
14 FERC ¶61,082 (1981)
(84%—12 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(84%—12 CP);

(4) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(87.8%—12 CP);

(5) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(81.2%—4 CP);

(6) *Commonwealth Edison Co.*,
15 FERC at 65,198
(79.4-79.5%—4 CP);

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(7) *Southwestern Public Service Co.*,
18 FERC at 65,035
(80.1%—3 CP); and

(8) *Delmarva Power & Light Co.*,
17 FERC at 65,202
(83.3%—12 CP).

b. Tests Relating to Reserves/Maintenance

To the extent a utility uses the off-peak months to perform its scheduled maintenance, FERC has found that supportive of the use of a 12 CP method. *Alabama Power Co.*, Opinion No. 54, 8 FERC ¶61,083, p. 61,327 (1979); *Illinois Power Co.*, 11 FERC at 65,249; *New England Power Co.*, Opinion No. 803, 58 FPC 2322, 2338 (1977); *Delmarva Power & Light Co.*, 17 FERC at 65,202. *But see Commonwealth Edison*, 15 FERC at 65,199.[139]

However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported. *See, e.g.*, *Illinois Power Co.*, 11 FERC at 65,249 (46 percent reserves after maintenance non-summer months and 34.5 percent for summer months—12 CP); *Commonwealth Edison Co.*, 15 FERC at 65,200 (for 1979 36.63 percent reserves after maintenance for 8 non-summer months and 22.15 percent for 4 summer months—4 CP).

c. Projection of CP and Total System Demands

In a number of cases, parties and the FERC Staff have challenged the filing company's estimated coincident peak or total system demand estimates.[140] While FERC appears to have established few hard and fast rules, the following cases provide some guidance. First, parties have challenged projections on the basis that the historical periods used were not representative. In some cases, FERC has held that multiple years of historical data should be

139. In *Southwestern Public Service Co.*, Opinion No. 337, 49 FERC ¶61,296, p. 62,152 (1989), FERC declined to depart from the 3 CP method based on "monthly load patterns and reserve margins as affected by scheduled maintenance" which "show that Southwestern's capacity requirements are largely determined by the peak demands imposed on the system during a three-month summer period."

140. In *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶61,509, p. 62,788 (1991), FERC accepted the Staff's method for deriving a coincident peak estimate. The Staff asserted that the noncoincident peak estimate must be divided by the diversity factor to convert each noncoincident peak demand into a comparable coincident peak demand. 55 FERC at 62,788-89. The "diversity factor is the noncoincident peak demand divided by the coincident peak demand." 55 FERC at 62,788 n. 87. FERC, however, noted that "[n]ormally, we would calculate the coincident peak demand for the sales for resales group by looking at its consumption at the time of Appalachian's peak. In this case, however, we have the forecasted monthly noncoincident peak demands for the customer group" and that "[u]sing the historical diversity factor for the group, we can derive the calculated coincident peak." *Id.*

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used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion No. 359-A, 54 FERC at 62,020 (accepted system peak demand and energy sales forecasts based on 1967-1981 data and 1981 coincidence factors). In other cases, FERC, however, has adopted CP projections based on the use of one year's data. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. In *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

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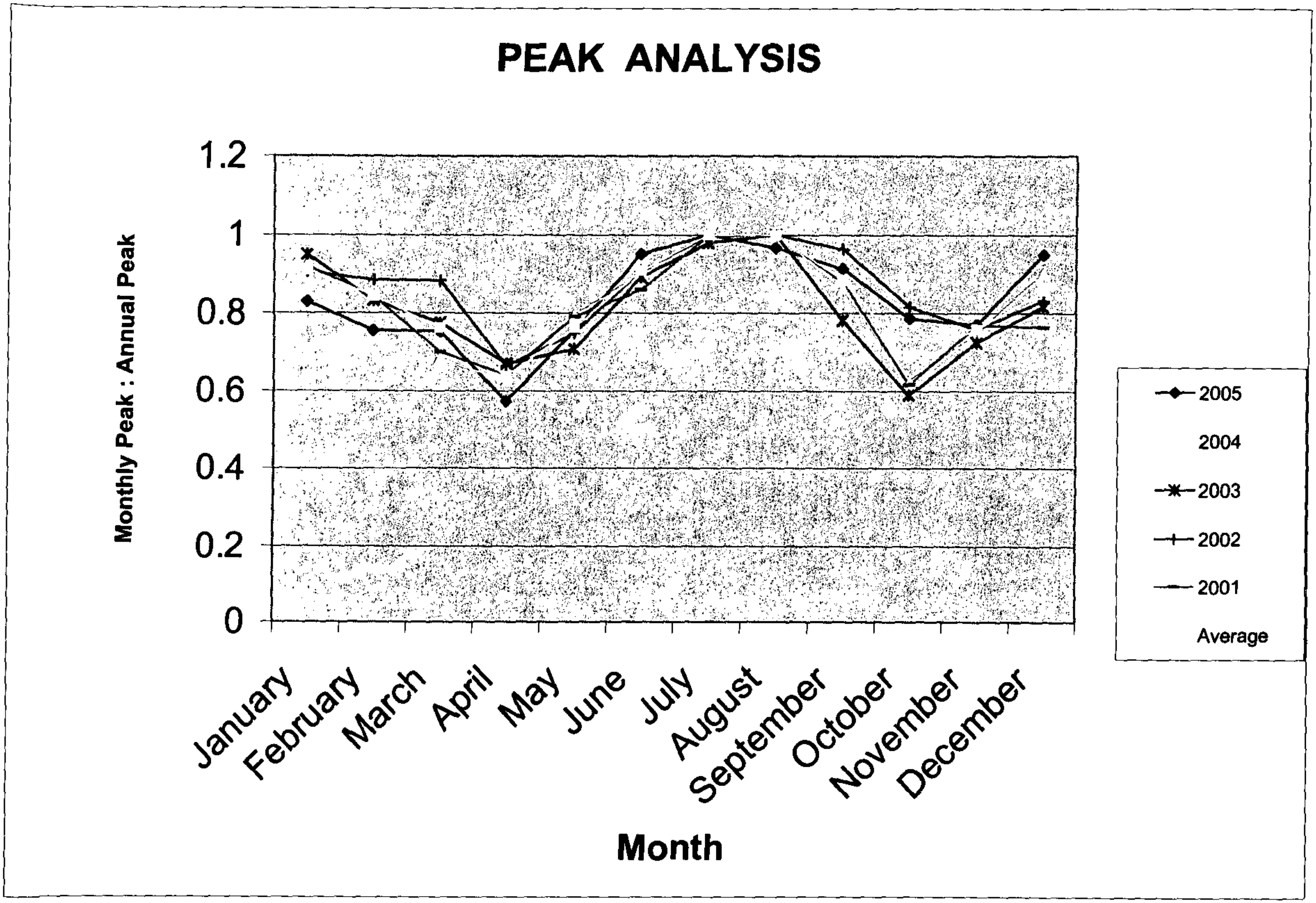
PEAK ANALYSIS
1.2
1
0.8
0.6
0.4
0.2
0
Monthly Peak : Annual Peak
January
February
March
April
May
June
July
August
September
October
November
December
Month
2005
2004
2003
2002
2001
Average

FERC Test Calculations

	Empire Monthly Peaks (MWs)
January	900
February	820
March	818
April	622
May	820
June	1033
July	1087
August	1050
September	991
October	854
November	837
December	1031

Minimum Peak	=		622		
Maximum Peak	=		1087		
Summer Month Avg	=		1040.25		
Other Months Avg	=		837.75		
12 Month Avg	=		905.25		
Ratio 1a = (Summer_Avg) / Max	=		0.95699172		
Ratio 1b = (8-Month_Avg) / Max	=		0.770699172		
FERC Test 1	=	Ratio 1a - Ratio 1b	0.186292548	=	18.63%
FERC Test 2	=	(12 Month Avg) / Max Peak	0.832796688	=	83.28%
FERC Test 3	=	Min Peak / Max Peak	0.572217111	=	57.22%