Exhibit No.:	
Issues:	Demand and Energy Jurisdictional Allocation
Witness:	Erin L. Maloney
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Surrebuttal Testimony
Case No.:	ER-2006-0314
Date Testimony Prepared:	October 6, 2006

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

SURREBUTTAL TESTIMONY

OF

ERIN L. MALONEY

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

Jefferson City, Missouri
October 2006

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	)))))	Case No. ER-2006-0314

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 following Surrebuttal Testimony in question and answer form, consisting of 7 pages of Surrebuttal Testimony to be presented in the above case, that the answers in the following Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

Erin L. Maloney

Subscribed and sworn to before me this 5th day of October, 2006.

Susan L. Sundermeyer

Notary Public

My commission expires 9-21-10

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

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SURREBUTTAL TESTIMONY

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KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

Q. Please state your name and business address?

A. Erin L. Maloney, Missouri Public Service Commission (MPSC), P.O. Box 360, Jefferson City, Missouri, 65102.

Q. Are you the same MPSC staff member Erin L. Maloney that filed direct and rebuttal testimony in this case?

A. Yes I am.

EXECUTIVE SUMMARY

Q. Can you please summarize your surrebuttal testimony in this case?

A. I am filing this surrebuttal testimony to respond to the information presented in the rebuttal testimony of Kansas City Power & Light Company (KCP&L) witness Don A. Frerking with regard to demand and energy jurisdictional allocation, as well as unused energy allocation. In particular I: a) attach pages that were inadvertently omitted from schedule 3 of my direct testimony; b) show how the missing pages support my recommendation to use a 4 CP methodology; c) further discuss why my recommendation to use a 4 CP methodology is appropriate; and d) discuss why it is appropriate to use an energy allocator to allocate variable costs.

JURISDICTIONAL DEMAND ALLOCATOR

Q. Do you have any changes or adjustments to make to your previously filed testimony in this case?

A. Yes I do. As Mr. Frerking pointed out, there were missing pages in Schedule 3 attached to my direct testimony which contained 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. I have attached this guide to this surrebuttal testimony as Schedule 1. It will be noted that the pages, which Mr. Frerking correctly identified as missing, were every other page.

Q. Were these pages omitted intentionally?

A. No. The pages were omitted inadvertently. The original document was two sided and I mistakenly did not copy the even number pages to be scanned and attached to my testimony.

Q. Was there relevant information contained in the missing pages?

A. Yes. As Mr. Frerking stated (Frerking rebuttal, pg. 5, lns. 1-3), appearing on the original page 106 of that publication is the following quote from FERC, which cites additional factors that FERC has considered in determining which allocation method is appropriate: "[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." Carolina Power & Light Co., Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978).

Q. Did the FERC always recommend a 12 CP methodology as a result of these factors?

A. No. These factors should be just one of the considerations when determining which methodology should be used. Cited on the same missing page as the Carolina cite, is another case, Commonwealth Edison Co., 15 FERC ¶63,048, p.65,196 (1981), where the FERC recommended a 4 CP approach.

Q. Would you expect the application of the system demand tests used in your analysis to result in the same recommendation for every utility studied?

A. No. There would be no reason to conduct an analysis if the same recommendation was expected.

Q. Have you been consistent with your application of these system demand tests?

A. Yes I have.

Q. What is the reason for using a different jurisdictional demand allocation methodology for different utilities?

A. Different jurisdictions within a utility's footprint may place different peak demands on that utility's system. Generation and transmission facilities that directly benefit all jurisdictions should be allocated using a methodology that reflects the demand placed on those assets by each of the jurisdictions that are served. A utility company's system should be designed, constructed, and operated to avoid loss of load and to serve and meet the native load demand that the utility has been granted exclusive privileges to serve.

Q. In his rebuttal testimony Mr. Frerking refers to your 12 CP recommendation (Frerking rebuttal, pg. 4, lns. 17-18) in Case No. ER-2006-0314, the rate case of the Empire District Electric Company (Empire). Why did you make a different recommendation in that case?

A. Two of the three system demand tests in that case indicated that the use of a 12 CP allocator would be appropriate. Because one of the tests results indicated the use of a 4 CP allocator, I looked at the other operational realities experienced by Empire and concluded that the use of a 12 CP allocator was indicated.

Q. What are the operational realities experienced by Empire that influenced your recommendation?

A. Empire experiences significant winter peaking because the saturation of electric heating among Empire's customers is high due to the fact that Empire serves a more rural territory in which the gas distribution system for winter heating is not as developed as in KCP&L's territory.

Q. Do both KCP&L and Empire experience the operational realities we have been discussing in the same way?

A. No. Empire is a dual peaking utility with large winter load demands due to electric heating. In contrast, KCP&L experiences only a summer demand peak. Furthermore, because of the existence of a winter peak, Empire has a much shorter window of opportunity to do scheduled maintenance. In addition, Empire has a high percentage of peaking generating units, while KCP&L has a high percentage of base load units.

Q. The FERC guideline mentioned earlier in this testimony also identified "off-system sales commitments" as an operational reality. How did you interpret what the FERC referred to as "off-system sales commitments"?

A. Because this guide was published before the change to the current electric spot market (1994), I interpreted the statement as a reference to capacity sales contracts. Capacity contracts must be considered because embedded in these contracts is a demand charge that

KCP&L's capacity contract customers pay in order to insure that the capacity is delivered. In other words, they are paying a fee so that plant is committed to fulfill that contract.

Q. Do sales on the spot market have a demand charge?

A. No. Spot sales, also referred to as **non**-requirement sales or **non**-firm sales, are sales of energy and do not carry a demand charge because there is no plant obligated or required to meet those sales.

Q. On page 7, line 3 of Mr. Frerking's rebuttal testimony he attempts to quantify the effect of incorporating spot market sales into the FERC system demand tests you used in your analysis. Does this make any sense?

A. Not at all. We are discussing system demand and how fixed costs should be allocated to the various jurisdictions. For the reason stated above, spot market sales or as Mr. Frerking refers to them, non-firm off-system sales, while an important source of revenue to KCP&L, should play no part in **this** analysis. Moreover since Mr. Frerking could not come up with a load requirement for spot market sales (such a thing does not exist), he uses energy instead of demand in his calculations. This is a totally incorrect application of the system demand tests developed and used historically by the FERC to determine a demand allocator methodology.

Q. What jurisdictional demand allocation methodology (12 CP or 4 CP) did KCP&L use in its last rate increase case and in its surveillance reporting since that case until the year 2005?

A. KCP&L used a 4 CP demand allocator in the last rate increase case and a 4 CP allocator since that rate case in its surveillance reporting up through 2004. In 2005, KCP&L switched to a 12 CP allocator.

Q. Was there a significant change in the monthly peak demand between 2004 and 2005?

A. No.

Q. What is the effect of using a 12 CP demand allocator as opposed to a 4 CP allocator on the Missouri rate payers?

A. A 12 CP methodology would allocate more plant to Missouri rate payers. Although there is only a fractional difference in the allocator (4 CP – 53.46%, 12 CP - 53.93%), this difference gets amplified when applied to large costs through out the rate case.

Q. What is the combined effect of KCP&L's recommendation to use a 12 CP demand allocator to allocate fixed costs and its newly developed "Unused Energy" allocator to allocate the margin on non-firm off-system sales?

A. KCP&L, in effect, is asking Missouri rate payers to pay for more of plant and other fixed costs while receiving less of the profits made from those plants

JURISDICTIONAL ENERGY ALLOCATOR

Q. Mr. Frerking states in his rebuttal testimony on page 9, lns. 4-5, that the Staff did not provide a rationale for using the energy allocation methodology for allocating the margins on non-firm off-system sales. Please comment.

A. I addressed the development and usages of the energy allocator in my direct testimony starting on page 10. Staff has traditionally allocated variable costs using an energy allocator.

Q. How was the energy allocator developed?

A. The energy allocator is based on the annual energy consumption by customers in each jurisdiction on a MWh basis.

Q. What is the difference between the energy allocator and the demand allocator?

A. The demand allocator is developed using the jurisdictional demands at time of system peaks and the energy allocator is based on the jurisdictional energy consumed. The demand allocator is used to allocate fixed costs such as production plant and transmission facilities, while the energy allocator is used to allocate costs that are variable in nature such as fuel.

Q. How does the energy allocator represent variable costs?

A. For each MWh of energy consumed there is a proportional increase in the costs (e.g. Fuel, Operations & Maintenance) used to generate that MWh. Using the MWh sales by jurisdiction properly reflects these variable cost components.

Q. How was the energy allocator derived?

A. I took the ratio of the adjusted MWhs used by jurisdiction to the total adjusted MWhs used in all of the jurisdictions on an annual basis.

Q. Does this conclude your prepared Surrebuttal Testimony?

A. Yes, it does.

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 (1983); *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...

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.

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> 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. 61,268 (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 ¶61,340 (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. 61,311 (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

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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.

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CP companies the numerator would consist of the average of the wholesale class's 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);

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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).

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(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,
3 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
(66%—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

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139 In *Southwestern Public Service Co.*, Opinion No. 337, 49 FERC ¶61,296, p. 62,132 (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, stated 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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