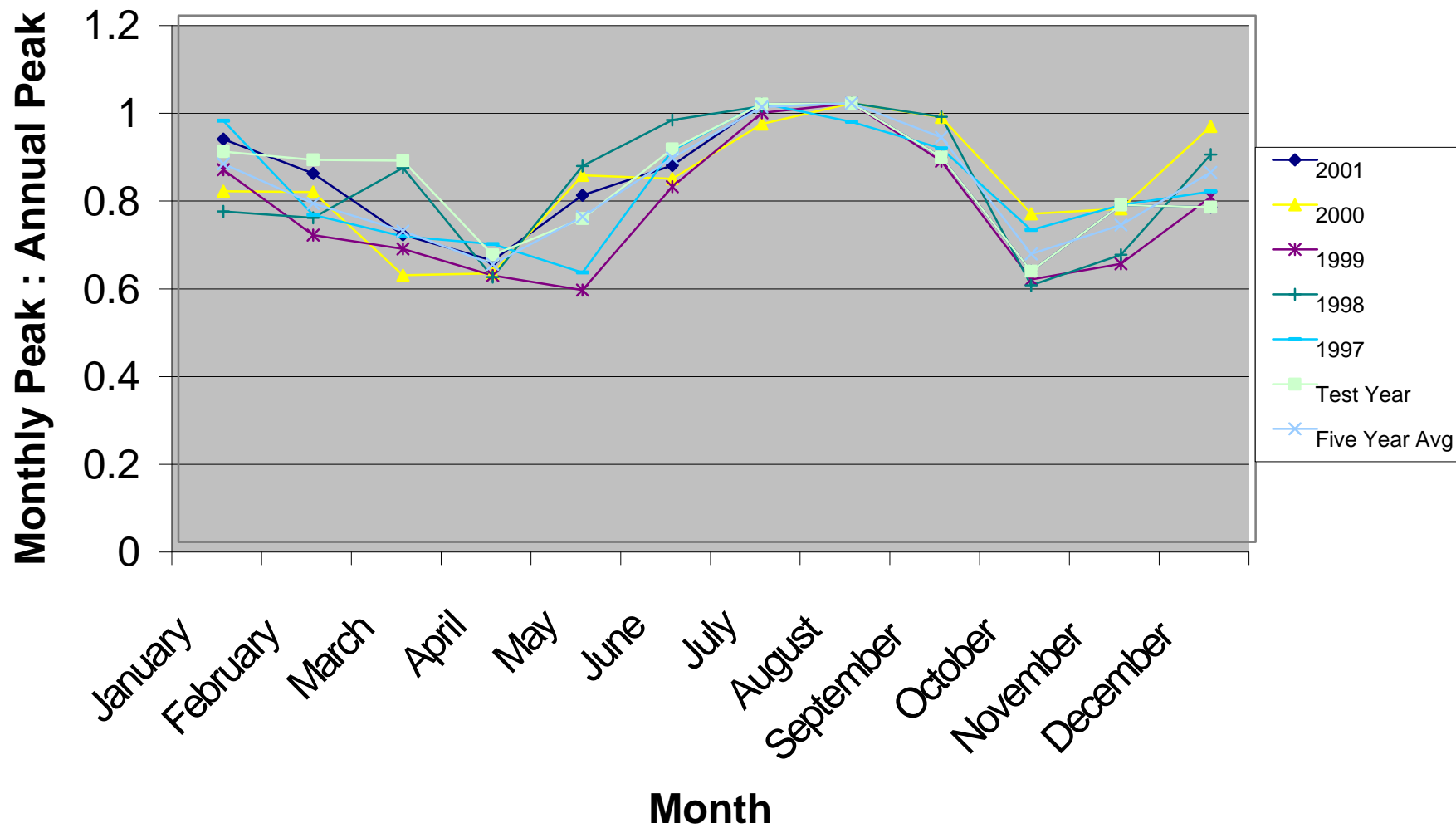


**SCHEDULE 1 IS DEEMED
PROPRIETARY
IN ITS ENTIRETY**

Monthly System Peaks (MW)

	2001	2000	1999	1998	1997	Updated Test Year	Five-Year Average
January	919	794	831	690	841	891	815
February	841	792	685	677	653	872	729.6
March	701	604	654	781	610	870	670
April	642	608	595	553	595	655	598.6
May	791	830	562	785	538	738	701.2
June	859.3	822	793	881	782	897	827.46
July	999	946	958	910	876	999	937.8
August	1001	993	979	916	839	1001	945.6
September	878	961	850	888	786	878	872.6
October	618	743	586	536	623	618	621.2
November	769	754	621	600	673	769	683.4
December	764	941	770	809	700	764	796.8

LOAD ANALYSIS



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.E.R. §35.13(h)(4)(iii) (plant); 18 C.E.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.

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*

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 *Lackhart 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.

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);

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,
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);

Schedule 4-5

- (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

Schedule 4-6

- (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);

Schedule 4-7

- (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. 62,132 (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.*

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).

FERC Test Calculations

January
February
March
April
May
June
July
August
September
October
November
December

Empire Monthly Peaks (MWs)

891
872
870
655
738
897
999
1001
878
618
769
764

Minimum Peak =

618

Maximum Peak =

1001

Summer Month Avg =

943.75

Other Months Avg =

772.125

12 Month Avg =

829.3333333

Ratio 1a = (Summer_Avg) / Max =

0.942807193

Ratio 1b = (8-Month_Avg) / Max =

0.771353646

FERC Test 1 =

Ratio 1a - Ratio 1b

0.171453546

= 0.1715

FERC Test 2 =

(12 Month Avg) / Max Peak

0.828504829

= 0.8285

FERC Test 3 =

Minimum Peak / Maximum Peak

0.617382617

= 0.6174

**SCHEDULE 6 IS DEEMED
PROPRIETARY
IN ITS ENTIRETY**

**SCHEDULE 7 IS DEEMED
PROPRIETARY
IN ITS ENTIRETY**