Exhibit No.:	
Issue:	Class Cost of Service
Witness:	Paul M. Normand
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2012-0174
Date Testimony Prepared:	September 5, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0174

REBUTTAL TESTIMONY

OF

PAUL M. NORMAND

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
September 2012

LIST OF TABLES

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REBUTTAL TESTIMONY

OF

PAUL M. NORMAND

Case No. ER-2010-0355

Q. Please state your name, address and position.

A. My name is Paul M. Normand. I am a management consultant and president with the firm of Management Applications Consulting, Inc., 1103 Rocky Drive, Suite 201, Reading, PA 19609. I am testifying on behalf of Kansas City Power & Light Company ("KCP&L" or the "Company")

Q: Are you the same Paul M. Normand who prefiled Direct Testimony in this matter?

A: Yes, I am.

Q: What is the purpose of your rebuttal testimony?

A: To provide rebuttal comments to the direct testimony filed by other parties in this case concerning Kansas City Power & Light's ("KCP&L" or "Company") class cost of service ("CCOS") study.

Q: Have you reviewed the testimony filed by other parties concerning the Company's CCOS study?

A: Yes, I have.

Q: Please describe that testimony?

A: Testimony related to KCP&L's CCOS study was filed by the Staff of the Missouri Public Service Commission of the State of Missouri ("Staff" or "Commission"). Staff also prepared a separate CCOS study report which was part of Staff witness Michael S. Scheperle's direct testimony.

Q: Did any other party other than KCP&L and Staff prepare and file a CCOS or offer CCOS-related summaries in this case?

A: Yes. Two additional witnesses prepared testimony and cost of service related details which I will be commenting on in this rebuttal testimony—Mr. Maurice Brubaker and Dr. Dennis W. Goins representing large energy users served by KCP&L. I have also reviewed the testimony of Ms. Barbara Meisenheimer (OPC) and have no comment as she indicated that my cost of service results are reasonable.

Q: Could you briefly show a comparison of the various CCOS presented in this filing?

A: The following (Table 1) class cost of service rates of return for the provided studies:

Table 1

MO Customer Class	KCP&L (BIP)	Goins' DOE (4 CP)	Brubaker's Industrial (A&E-4 NCP)
Total Jurisdiction	5.54%	5.54%	5.54%
Residential	5.43%	2.70%	2.30%
Small Gen. Service	10.97%	10.21%	11.18%
Medium Gen. Service	7.09%	7.25%	7.86%
Large Gen. Service	5.80%	7.41%	7.86%
Large Power	3.01%	7.08%	7.67%
Total Lighting	6.19%	31.24%	12.80%

Note: MPSC Staff utilized a different method to perform their study ROR not directly available.

Q: What is the purpose of the CCOS study?

A: The purpose of a CCOS study is to directly assign hundreds of differing cost elements from Company records in a rational and equitable manner in order to determine the proper cost to serve the Company's customer classes under study.

Q: How do you determine an appropriate rate structure?

A: There are generally two steps to establishing a proper rate schedule: a class cost of service study and a rate design analysis.

Q: How is this analysis used to determine customer rates?

A: The results of the CCOS study are used to provide guidance in establishing class revenue targets and applying any overall rate change to the Company's individual customer classes. Once the overall revenue target is assigned to the individual classes, the CCOS study can be used to examine individual rate designs and make changes to the rate components of customer charge, demand charge, and energy charge.

Q: Is there a fundamental difference between the Staff's CCOS study approach and the Company's CCOS study?

A: Staff's overall approach to recognizing the importance of distinguishing various generation fixed and variable costs by type of generation based on the Base, Intermediate, and Peaking (BIP) method is consistent with the cost of service study that I presented. By using the BIP method, Staff has also recognized the importance of production class allocation by matching the use and benefit of almost three-quarters of KCP&L's costs of service. By layering these costs and synchronizing their respective class allocation factors in a more robust cost responsibility assignment, a much more equitable class allocation can be achieved. (See Staff Report, pages 10-15.) Contrary to Dr. Goins' and Mr. Brubaker's assertions, this approach to production allocation is well recognized in the industry, and I have used this approach as well as similar methods for over 30 years. Admittedly, the method does require more data and preparation than the more simplistic 4 CP method or A&E schemes, however the additional effort is warranted to properly consider the allocation of major base load units to the company's production plant since this represents over seventy percent of all costs (see Table 3). I should also note that I have never advocated the use of a 4 CP production allocator as it is inappropriate for large base units which are used to generate electricity for virtually all hours of the year and are the major cost component for KCP&L's revenue requirements. Attachment 1 is a description of the various production allocation factors taken from the NARUC Cost Allocation Manual (1992) that have seen considerable use.

My disagreement with respect to Staff's production approach is primarily in the second step with respect to the cost allocations to customer classes once the identification by type of generation was identified as follows:

Table 2

Production Plant	**Staff**	**KCP&L**
Base Units	Annual Energy	Base Energy
Comment:	*Staff's approach double dips small users, e.g. Residential and Small General Service, by using total annual energy.*	
Intermediate Units	12 NCP Less Base	12 CP Less Base
Comment:	*Staff magnifies the class allocation amount based on NCP for smaller users, e.g. Residential, rather than recognizing the monthly CP limitation.*	
Peaking Units	4 NCP Less Base & Immediate	4 CP Less Base & Intermediate
Comment:	*Staff continues to magnify the class allocations to smaller Residential users by basing their allocator on NCP levels versus a 4 CP level.*	

Q: Why do you disagree with Staff's production class allocation approach in their CCOS?

A: The structure of Staff's approach was essentially quite similar to what I proposed for KCP&L using the BIP; however the choice of multiple non-coincident peak or NCP data for the class allocation of intermediate and peaking units incorrectly skews the production plant allocation results somewhat from my study towards smaller use customers.

Q: Please explain.

A: As mentioned in the comments of Table 2, the use of multiple NCP data serves to incorrectly increase the cost allocation to the Residential class for what are total integrated system costs. These total demand levels are far greater than any one hour of generation requirements. This is because utilities dispatch generating capacity to match hourly peaks. NCP methods are traditionally utilized for allocation of distribution plant where it is desirable to recognize the higher undiversified demands imposed on facilities located closer to customers.

Q: And what is the outcome of this difference with respect to the results of Staff study?

A: As mentioned in the comment of Table 1, Staff did not produce a rate of return as part of their study so direct comparison with the other studies is not directly available.

Q: Have you reviewed the direct testimonies of Dr. Goins and Mr. Brubaker?

A: Yes, I have.

Q: Are there any fundamental differences between Dr. Goins' and Mr. Brubaker's CCOS study approach and the Company's CCOS study?

A: Yes, both Dr. Goins and Mr. Brubaker provide a modified version of my study and chose to limit their presentation to the major classes. Since their studies do not break down costs by season or by any further detail than Class level, their studies provide very limited insight into any comprehensive rate design proposal.

Q: Do you agree with their recommended use of a 4 CP or A&E-4 NCP allocation from production and transmission facilities?

A: No, I do not. Their demand allocation recommendation has very limited use in the allocation process especially for production facilities where 71.6% of total revenue requirements are for the Production function only (52.1% Demand and 19.5% Energy). In situations where all customers do not exhibit the same usage characteristics or where all production facilities are only peaking types with the same cost structures, these class allocation methods incorrectly produce rather large cost allocation shifting and class inequities.

Q: Why is it important that production allocation methods such as the BIP be reasonable?

A: The use of a production stacking approach such as the BIP to the class allocation for the largest portion (approximately 69.6%) of a utility's demand costs is by far the most representative procedure that mirrors both the planning as well as the operation of any utility's production facilities.

Utilities must provide energy for all hours of the year based on a load duration curve which is simply the combined hourly usage of all customers. To accomplish this, the overall resource planning effort is quite complex and considers a myriad of costs and engineering factors associated with planning.

The BIP method allows for a more complete recognition of the dual nature of generating resources and provides a more structured and precise way to model the costs and develop appropriate class allocators for production plant.

Q: What is another important aspect in the allocation of production plant?

A: From both a planning and operation point of view, there are two costs that represent production facilities: fixed and variable. Unless these two costs are synchronized in the allocation process, a potentially severe and material misallocation will occur in class cost allocation. This can be clearly evidenced by simply reviewing my Schedule PMN-3 of my Direct Testimony at a Uniform Rate of Return (8.56%) section (Page 29). The various unbundled costs which make up the total revenue requirement for the Company based on the cost of service assumptions included in the model are as follows:

Table 3

	($M)	% Demand $	% Total $
Demand			
Production	419.0	69.6	52.1
Transmission	48.0	8.0	6.0
Distribution	135.3	22.5	16.8
Total Demand	602.3	100.0	74.9
Energy	157.2		19.5
Customer	45.1		5.6
Total Company	804.6	100.0	100.0
Total Production	576.2		71.6

The total production-related costs equal 52.1% (Demand) plus 19.5% (Energy), or 71.6% of total costs. Allocating 52.1% of all revenue requirements on simply one, two or four coincident peaks is misleading, unadvisable, and will distort the class allocation away from larger energy users and, more importantly, deviate from the planning and operation process.

Simply recognizing that 71.6% of total revenue requirements relates solely to the Production function should emphasize that demand and energy cost allocation be synchronized. Advocating any Coincident or Class Peak method for Production Demand costs (52.1%) does not fully address the purposes of the plant since these very costs produce the related Energy costs (19.5%).

Q: Does the Average and Excess-4 NCP (A&E-4 NCP) or 4CP allocation approaches proposed by the other parties provide a more reasonable approach to allocation?

A: No, it does not. Each proposed method is recognized by NARUC in their cost allocation manual and represents a method where a party may allocate costs on the basis of their point of view. While I believe any A&E or 4CP method is not appropriate in this context as it will shift costs to customer classes that rely more on demand consumption rather than energy consumption, the results may be considered by the Commission in determining the rate design in this case.

Q: Are results from a CCOS study showing class rate of return levels and a comparison of each return to the overall Company meaningful?

A: Yes, they are. The CCOS study develops a final class ROR level which, based on the study's cost assignments, indicates the class return achieved. These results are then interpreted in rate proceedings as to the appropriateness of existing pricing level as approved by the Commission with respect to equitable and fair levels of class revenue recovery under a common analysis.

Q: So then are the CCOS study ROR results the final or ultimate benchmark from which to establish decisions as to proposed pricing objectives in a rate filing proceeding?

A: No, they are not. The existing ROR target and targeted proposed uniform ROR (all classes) revenue requirement levels simply provide information or a reference point to begin the process of establishing class revenue targets and rate design objectives. However, there are many more important factors that must be considered in any proposed rate design that will generally include:

a) level of increase to equalized ROR;

b) allowed overall increase limitation (rate capping);

c) gradualism and customer impact; and

d) economic considerations.

Oftentimes, these goals are conflicting and their application muted by additional factors such as the economy, job creation, discounts, etc.

Q: Is the class ROR principle rigid in its application?

A: No, it is not. The class cost of service study results are but a snapshot in time, and most regulators view them as such. In fact, a common goal in ROR application is that the ultimate goal is to reach a class ROR target that is within a bandwidth of the overall system target. For example, if the Commission authorized an overall 9.5% ROR, then that Commission might identify an ideal cost of service application where all classes would achieve a ROR level or bandwidth of between 8.5 to 10.5 (± 1) levels based on the overall allowance. In the industry, this is often referred to as a "zone of reasonableness." Unfortunately, this is rarely achieved in the industry and in response to the need to gradually change rates, can require many rate cases to even come close to achieving such a goal.

Q: Do you have similar concerns with the proposed allocation of transmission plant?

A: Yes, I do. While the transmission component of total revenue requirements is much less (6.1%), the basic arguments are the same with respect to the Company's transmission facilities.

Q: What allocation factor did you propose for transmission plant?

A: I proposed the use of a 12 CP which considers all of the Company's monthly peaks as the most representative of the Company's entire transmission plant investments. In doing so, my approach provides the following benefits:

1 – Well recognized method;

2 – Easily replicated;

3 – Much more stable and equitable than the very limited CP methods;

4 – 12 CP better captures the backbone high voltage system;

5 – Inherent in this 12 CP method is an energy association that is implied; and

6 – Excludes the inadequate allocation of total energy as proposed by Staff.

Q: Are there any customer-related costs as discussed by Mr. Brubaker in his testimony on pages 10 and 11?

A: No. There are no distribution-related costs that are based on the number of customers. The minimum or "skeleton" distribution system is a phantom, non-existing since that is rarely developed with any rational cost analysis and is rarely recognized by regulators as a valid costing approach.

Q: Does Mr. Brubaker's Figure 2 on page 11 of his testimony reflect an accurate representation of typical distribution systems that support his discussion on pages 10 and 11?

A: No. It is not reflective of generally installed facilities on any power system.

Q: Since your review of Staff's and other intervenors' testimonies, do you still believe the results of KCP&L's CCOS study as proposed provide the most reasonable results?

A: Yes, I do. My approach is more realistic and more closely matches the planning and operations of KCP&L's power system for all functional cost levels. This same approach was recently proposed and filed in KCP&L's Kansas filing, Docket No. 12-KCPE-764-RTS and adopted by the Commission in the Company's prior Docket No. 10-KCPE-415-RTS.

Q: Did the Commission in Kansas accept your approach?

A: Yes, in the final order dated November 22, 2010 the Commission endorsed my approach and stated that "the BIP method provides more structure for modeling costs of production plant and use of generating resources. It also allows for a detailed examination of seasonal costs and corresponding seasonal rate allocations." Attributes that are also directly relevant to this case.

Q: Did the parties rely consider their CCOS study result in proposing a rate design alternatives?

A: Yes, despite the issues previously identified, the parties utilized their studies to propose rate design changes. My study served as the basis for rate design alternatives addressed by Company witness Tim M. Rush in his Rebuttal Testimony.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2012-0174

AFFIDAVIT OF PAUL M. NORMAND

COMMONWEALTH OF PENNSYLVANIA)
) ss
COUNTY OF BERKS)

Paul M. Normand, being first duly sworn on his oath, states:

1. My name is Paul M. Normand. I am a management consultant and president with the firm of Management Applications Consulting, Inc. in Reading, Pennsylvania. I have been retained by Great Plains Energy, Inc., the parent company of Kansas City Power & Light Company, to serve as an expert witness to provide testimony on behalf of Kansas City Power & Light Company.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of twelve (12) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Paul M. Normand

Subscribed and sworn before me this 5TH day of September, 2012.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
CINDY A THOMASON, NOTARY PUBLIC
SOUTH HEIDELBERG TWP, BERKS COUNTY
MY COMMISSION EXPIRES OCT 06, 2013

Notary Public

My commission expires: 10/06/13

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.