1. COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

DOMTAR PAPER COMPANY, LLC'S RESPONSE TO BIG RIVERS ELECTRIC CORPORATION AND KENERGY CORP.'S FIRST REQUESTS FOR INFORMATION

---

1. Refer to the testimony of Mr. Stephen Baron, page 3, lines 9-13. Please provide the referenced *Public Utilities Fortnightly* article.

RESPONSE:
See attached.

2. Refer to the testimony of Mr. Stephen Baron, page 3, lines 9-13. Please provide the testimony and any other documents sponsored by Mr. Baron in the referenced Arkansas Power and Light Company proceeding in Docket No. 87-183-TF.

RESPONSE:
See attached.

3. Refer to the testimony of Mr. Stephen Baron, page 3, lines 9-13. Other than the cited case, does Mr. Baron have any other specific experience in the development of a standby and maintenance power rate? If so, please describe that experience and include case or docket numbers of regulatory proceedings that Mr. Baron has testified in on the subject of standby and maintenance power rates.

RESPONSE:
Mr. Baron participated in Appalachian Power Company/Wheeling Power Company Case NO. 15-1734-E-T-PC, "Tariff Filing for Approval of Two New Riders for Demand Response and a New Standard Backup and Maintenance Service Schedule and Consent for and Approval of Certain Ratemaking for the Proposed DR Riders."

Based on Mr. Baron's review of his Exhibit SJB-1, and his recollections over a 40 plus year period, he does not believe that he has participated in other Standby/Maintenance Power proceedings or designed such rates in the course of other projects.

4. Refer to the testimony of Mr. Stephen Baron, page 7, lines 7-18. Are you aware of any differences in planning or cost that may accompany the provision of service to a 30 MW load versus a 1.5 MW load? Please explain in detail why you believe that any such difference(s) may or may not exist.

RESPONSE:
Based on Mr. Baron's review of BREC Schedule LIC, there is no difference in the cost between service to a 1.5 MW load and a 30 MW load as long as both loads are served using a dedicated delivery point ("This schedule is available to any of Big Rivers' then existing Member Cooperatives for service to Large Industrial Customers served using dedicated delivery points").

5. Refer to the testimony of Mr. Stephen Baron, page 10, lines 7-8. Please describe in detail and provide copies of all support relied upon for the conclusion that "[i]f Domtar's 52 MW QF did not exist, then the planned in-service date of Big Rivers' 635 MW NGCC would be moved up."

RESPONSE:
Mr. Baron based this statement in his testimony on the fact that, all else being equal, Big Rivers' load obligation would increase by 52 MW, absent the Domtar QF. Mr. Baron did not perform any specific planning analyses evaluating the timing of future generation additions.

6. Refer to the testimony of Mr. Stephen Baron, page 12, lines 1-12. Please explain what additional demand-related costs a utility should recover from a customer seeking maintenance power that are not already recovered from that customer in connection with the utility's provision of backup power. If none, explain the need for separate rates.

RESPONSE:
As explained in Mr. Baron's testimony, the cost to provide maintenance power is lower than the cost to provide backup power, since maintenance power is scheduled by the customer during off-peak periods. In the case of DEK's GSS tariff, which Mr. Baron has used as a model for developing his proposed Backup and Maintenance Power rate for Big Rivers, the pro-rata charge for maintenance power capacity is 50% of the standard industrial power rate, versus 100% of the rate (on a pro-rata basis) for backup service. As such, it is necessary to have a separate rate for maintenance power. Also, the Commission Order establishing this case required separate pricing for maintenance and backup service.

7. Refer to the testimony of Mr. Stephen Baron, page 12, lines 13-21. How does Domtar propose that Big Rivers and/or Kenergy determine a customer's generation reliability factor? If Big Rivers and/or Kenergy relies on this factor and utilizes the factor in its capacity planning, but the customer's generation is ultimately less reliable than anticipated (e.g., due to poor maintenance practices, unrelated operational issues, etc.), does Big Rivers and/or Kenergy bear the cost-related and reliability-related risks attendant to the unplanned need for energy?

RESPONSE:
Based on the DEK type rate design that Mr. Baron has proposed, it is not necessary to specifically determine the reliability factor associated with a Standby customer's generator. Because the customer is charged based on a pro-rata share of the standard LIC demand charge, the actual experienced reliability is being charged at an adjusted LIC standard demand charge rate. In other types of Standby tariffs customers can be assigned a certain assumed reliability factor, which if exceeded, results in a higher Standby charge that may continue for 12 months. In other types of Standby tariffs (e.g. Kingsport Power Company), the customer selects a level of reliability based on the customer's expectations. If the customer's generator underperforms, there would be penalties applied to the customer.

8. Refer to the testimony of Mr. Stephen Baron, Table 2 and accompanying text, Exhibits SJB-11, SJB-12. Please provide all documents and information upon which you relied in connection with this analysis, including all workpapers in functioning electronic format with formulas intact.

RESPONSE:

See attached Confidential and Proprietary Excel workbook.

9. Identify in detail all efforts, historical and current, with respect to the accreditation of Domtar's generator as a behind-the-meter generator with MISO. Please provide all related communications and documents. Please identify all amounts earned as Capacity Payments as a consequence of any accreditation, current status, and the reasons underpinning any historical changes in status.

RESPONSE:

Domtar has not made any direct effort to register the Hawesville behind-the-meter generator with MISO. All communications to or from MISO have gone through BREC. Capacity payments were presumably netted out in the BREC billing based on the annual Capacity Settlement statement provided by BREC. The 2022/23 PRA year is included in the attached MS Excel workbook.

10. Refer to the testimony of Mr. Stephen Thomas, page 2, lines 17-20. Please identify and describe each of Domtar's mills and converting facilities in the US and Canada, including its location, source of energy supply, agreement or tariff pursuant to which it obtains energy, relevant RTO or balancing authority, on-site generation, detailed electricity cost information by month for past five (5) years.

RESPONSE:

Domtar objects to this Data Request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence and is unduly burdensome. Without waiving such objection, Domtar's converting facilities do not have on-site generation and thus do not require maintenance or back-up service. There are other Domtar paper mills similar to Hawesville but their on-site generation is sold separately so they do not require maintenance or back-up services. The only two relevant paper mills, Ashdown and Kingsport, were mentioned in my initial Testimony. And, Kingsport has only received service under a stand-by contract since April of this year. Prior to April 2023, Kingsport also sold its generation under an agreement separate from their electric supply agreement.

Ashdown purchases power from Southwest Electric Power Company ("SWEPCO") under SWEPCO's published and commission-approved Rate Code 326, "INDUSTRIAL PULP AND PAPER MILL" available at SWEPCO's Internet site:
https://www.swepco.com/lib/docs/ratesandtariffs/Arkansas/Arkansas_Compliance_Tariff_06-29-2022.pdf starting on Page 32 as Rate Schedule 9.

Kingsport purchases firm power from Kingsport Power Company, d/b/a AEP Appalachian Power, ("AP") under AP's published and commission-approved Industrial Power ("I.P.") Rate schedule. Back-up and Maintenance services are purchased under AP's Standby Service, ("S.B.S.") rate that includes costs for maintenance capacity and energy. There rates are available at AP's Internet site:
https://www.appalachianpower.com/lib/docs/ratesandtariffs/Tennessee/KGPT_Tariff3-FPPARNovember1_2023.pdf.

11. Refer to the testimony of Mr. Stephen Thomas, page 4, lines 21-22. Please describe and quantify the "historical price advantage on energy" that Domtar's Hawesville facility has experienced.

RESPONSE:

The per MWh cost of the BREC portion of Domtar's Hawesville Mill's has risen from $35.85/MWh in 2012 to $78.48 in 2023. This 118.9% increase has eliminated Hawesville facility's energy price advantage. I have included the annual per MWh costs on the "Q11" tab of the included work document and is as follows:

Year		Annual BREC cost [$/MWh]	Increase from 2012 [%]
2012	$	35.85	0.0%
2013	$	37.84	5.5%
2014	$	53.66	49.7%
2015	$	54.65	52.4%
2016	$	59.93	67.1%
2017	$	61.16	70.6%
2018	$	61.79	72.3%
2019	$	58.67	63.6%
2020	$	57.83	61.3%
2021	$	57.79	61.2%
2022	$	81.91	128.4%
2023	$	78.48	118.9%

12. Refer to the testimony of Mr. Stephen Thomas, page 7, lines 2-5. Please provide all documents and information upon which you relied in connection with this analysis, including all workpapers in functioning electronic format with formulas intact.

RESPONSE:

The MS Excel workbook titled "LICSS vs. Contract (Domtar Confidential).xlsx" is included in this filing. This was the singular document used for all of my included quantitative testimony. Please note that most of the information included in this work product is commercially-sensitive, proprietary and confidential to Domtar and should not be used for any work or analysis outside of this proceeding.

13. Refer to the testimony of Mr. Stephen Thomas, page 7, line 22. Please describe in detail Mr. Thomas's "regulatory background," and identify all regulatory matters in which Mr. Thomas has served as a witness. Provide a copy of any testimony, as well as a CV reflecting any publications, etc.

RESPONSE:

I have testified to commissions in MD, NC, and KY and or to their Public Staffs as well as having direct meetings with many past and current FERC Commissioners but have not retained records of the dates nor kept any written testimony. Please see the answer to the question on Lines 8-9 on Page 1 of my Direct Testimony for more the information about my educational and career backgrounds most relevant to my testimony.

14. Refer to the testimony of Mr. Stephen Thomas, page 10, lines 9-21. Regarding the "alternative proposal," please explain whether and how it ensures Big Rivers' recovery of costs necessarily incurred to provide the standby service, including (but not limited to) the costs to build and maintain the infrastructure required to serve all load. Please identify and describe in detail Domtar's "revenue obligations to the shared system."

RESPONSE:
Domtar's revenue obligations to BREC are met through our purchase of firm energy and capacity under BREC's LIC rate. The back-up and maintenance portions would be supplied by the MISO at MISO's cost to BREC. Since this cost would be passed-through directly to the stand-by customer, it would, therefore, insulate BREC and other BREC customers from variations in the cost of this supply.

15. Refer to the testimony of Mr. Stephen Thomas, Exhibit 2. Please provide all documents and information upon which you relied in connection with this analysis, including all workpapers in functioning electronic format with formulas intact.

RESPONSE:
See my answer to #12 above.

16. Please provide a copy of any agreement between Domtar and Mr. Baron.

RESPONSE:
There is no such agreement.

17. Please identify any RTOs from which Domtar or any of its operating affiliates has sought accreditation for behind the meter generation. For each such instance, please provide the following information:

i. identify the name of the RTO;

ii. describe in detail the process followed in order to obtain accreditation;

iii. identify the amounts and nature of all costs incurred in connection therewith;

iv. identify the nameplate capacity for the behind the meter generation accredited;

v. identify the capacity for which the RTO accredited you and the date(s) of accreditation; and if accreditation was denied (in whole or in part), provide a detailed explanation of why accreditation was denied and all documentation provided by the RTO regarding such denial.

RESPONSE:
Domtar has no facility in the US where its behind-the-meter generation is registered with the regional RTO.

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS	**)**	
ELECTRIC CORPORATION AND KENERGY	**)**	**Case No. 2023-00312**
CORP. TO REVISE THE LARGE INDUSTRIAL	**)**	
CUSTOMER STANDBY SERVICE TARIFF	**)**	

ATTACHMENTS

A Realistic Approach to Standby Electric Rates

By STEPHEN J. BARON

In setting rates for backup service to cogenerators and other customers having independent sources of generation, electric utilities have relied heavily upon traditional principles of rate design. Standby contract demand charges typically fail to take into account the probability of power actually being needed. The approach to setting rates introduced in this article considers the specific characteristics of standby customers and facilitates cost-of-service analysis and system planning for electric utilities.

THE rapid increase in cogenerated and self-generated electric power by industrial firms and large institutions in the 1980s has created a need to reexamine the fundamentals of standby electric rates. Standby power is usually provided by electric utilities to nonutility customers who have their own indigenous sources of electric generation. It is generally used to provide backup service in the case of planned maintenance of the customer's own generation or emergency power in the case of a forced outage. Since there have been only a relatively small number of nonutility electric producers in the past, standby power has not been a significant utility service. For this reason, the development of standby electric rates has received little attention from regulators and potential users.

By 1980, standby rate design was no longer an obscure issue. In almost all cases, cogenerators and self-generators must rely on standby power as part of their overall electric production operation. From the utility's viewpoint, there are certain (albeit difficult to quantify) costs associated with providing this backup demand and energy, as standby power is sometimes referred to. The major issue of standby rate design is the cost basis for developing the rate.

Stephen J. Baron is a vice president and principal with Kennedy and Associates, a firm of utility rate, economic, and planning consultants located in Altanta, Georgia. Earlier, he was a manager with the Utility Regulatory and Advisory Services Group of Coopers & Lybrand and was a vice president of energy management services with Ebasco Business Consulting Company. **Mr. Baron** has a BA degree and an MA degree in economics, both from the University of Florida.

In general, the traditional approaches to standby electric rate design have employed contract demand charges for each kilowatt of standby load. This contract demand charge is paid monthly, whether or not the standby power is actually utilized and represents a reservation charge for the capacity necessary to serve the standby load. Energy charges are normally based on current general service or large industrial rates and are only initiated and billed when standby power is actually consumed. In other words, there is no reservation charge for energy, only for capacity. On the surface, this seems to be a reasonable approach. A fixed reservation charge for a contract amount of standby capacity and an energy charge which only takes effect when standby power is used. Controversy surrounding standby electric rate design tends to be associated with: (1) the amount of the contract demand charge, and (2) the approach used to compute the contract demand.

Charges for standby contract demand are typically based on the demand charge in the standard large general service rate and, in many instances, are actually identical to that demand charge. In most cases, formal cost studies are not used to develop the cost of standby power. Given the lack of a cost study, the best proxy for estimating the cost of standby contract demand is the existing firm service rate. One reason for this lack of cost analysis is that traditional cost allocation techniques do not recognize the costs associated with providing standby power. Regardless of the cost allocation technique employed, it is quite conceivable that during a given test year only minimal standby power was provided to contract users. For example, standby power may have been provided for planned maintenance and some minor forced outages, all of which occurred during off-peak periods. Using traditional cost allocation techniques, the standby rate class would be allocated little or no demand-related costs. As a result, utilities have tended not to use cost studies in standby rate design.

The second aspect of the standby rate issue, and perhaps the most controversial, is the determination of the contract demand. Contract demand is usually defined as the maximum potential amount of reserve power (kilowatts) required, regardless of the probability of usage. If an industrial cogenerator or self-generator generates 50 megawatts of power and requires a constant firm load for process use of at least half that amount (25 megawatts), the customer might contract for 25 megawatts of standby power. Controversy on the computation of contract demand stems from differences in the probability that standby power will be required on the part of the user. Under most standby rates, the charges for 25 megawatts of contract standby power would be the same regardless of the probability that the demand would actually be placed on the utility system.

An example may be helpful. Assume that a utility has two industrial self-generators, each of which has 25 megawatts of contract standby demand. Now assume that Customer 1 has a production plant with an average availability of 90 per cent (excluding planned maintenance from the analysis). This customer's production plant would be forced out 10 per cent of the time and rely on the utility for backup power during these periods. The second customer is assumed to have an availability of 99 per cent, requiring standby power from the utility only one per cent of the time (again ignoring planned maintenance). Since the standby rate design does not reflect the probability of standby power actually being required, each of the customers would pay the same charges for their respective 25 megawatts of contract demand.

In cases where the contract demand charge is the same as the firm service demand charge, this would suggest that 25 megawatts of system production capacity has been reserved for standby use by each customer, regardless of the probability that it will actually be needed. In fact, the expected load on the utility from Customer 1 is the 10 per cent forced outage rate times the contract demand of 25 megawatts, an expected load of 2.5 megawatts. For Customer 2, the expected load on the utility is .25 megawatt. At any given time (including peak periods), the utility can expect 2.75 megawatts of load from these two customers despite the fact that they have actually contracted for 50 megawatts of contract demand. Table 1 illustrates these calculations. If we increase the example to 50 or 100 co- or self-generators, this concept of expected load would appear to be even more realistic. In fact, the utility could actually reserve and plan for capacity to meet the expected standby power requirements of the total group. (It should be noted that the analysis becomes more complicated if the random forced outages are not independent of time of day or season of the year.)

Use of a probabilistic approach to standby rate design has a number of implications for both cost-of-service analysis and system planning. Under a probabilistic approach, a standby rate class can be viewed as a firm power rate class for cost allocation purposes. If it is assumed that random forced outages on customer equipment are time-invariant, then the concept of identifying an expected value of standby rate class load would easily fit into existing cost allocation frameworks. A similar approach can be used for planning purposes. The expected value of the standby rate class load can be added to load forecasts at 100 per cent load factor.

In actual practice, a realistic rate design could be based on the characteristics of the entire standby rate class rather than on the behavior of any particular customer. This approach has a direct analogy to the techniques employed in traditional firm service rate design — for example, the assumption that all customers have an average class coincidence factor in a large general service rate, despite the fact that the actual relationship between maximum demand and demand at the time of the class peak may vary widely among customers within the class.

Using a class as the basis for standby rate design requires the development of an expected profile of all standby loads, with explicit consideration given to the probability distribution of the individual customer requirements. A basic premise in this approach is that standby loads need only be considered on an expected basis for planning and thus should be costed in a similar manner. Is this realistic? The answer depends on the size of the standby rate class and on the concept of diversity. Using a two-customer example (Table 2), all

TABLE 1
CALCULATION OF EXPECTED LOADS

Customer 1:

	25 Mw	Standby Load Requirement
×	.10	Forced Outage Rate
	2.50 Mw	Expected Load

Customer 2:

	25 Mw	Standby Load Requirement
×	.01	Forced Outage Rate
	.25 Mw	Expected Load

Total Expected Load:

	2.5 Mw
+	.25
	2.75 Mw*

*Forced outages are assumed independent and thus expected loads are additive.

TABLE 2
EXAMPLE — STANDBY LOAD "STATES": TWO CUSTOMERS

State	*Standby Load Requirements*	*Probability*
1	0	.81
2	25	.18
3	50	.01
		1.000

Expected Standby Load — five megawatts.
Assumptions: Customer 1 — 25 megawatts, .90 availability of customer generation equipment.
Customer 2 — 25 megawatts, .90 availability of customer generation equipment.

of the possible states can be computed with their associated probabilities of occurrence. (Note: Both customers in this example are assumed to have 90 per cent availability of customer generation equipment.) These probability states represent the various standby load requirements faced by a hypothetical utility at any point in time.

From Table 2, there is an 18 per cent chance that the standby requirements will be 25 megawatts even though on average the load will only be five megawatts. Considering this risk, can a utility plan to meet the expected load? The answer depends on the planning criteria of the utility. However, it seems reasonable that most utilities would not plan to meet the total potential load of 50 megawatts which only has a one per cent chance of occurring.

As more standby customers are added to the rate class, the planning risk of meeting the expected load becomes smaller. Table 3 illustrates a probability distribution of standby load with twenty customers, each having a 25-megawatt requirement with a 90 per cent availability of customer generation equipment. The expected value of the standby load is 50 megawatts. From the distribution in Table 3, there is only a one per cent chance of the standby load being greater than 125 megawatts at any point in time. Though this is greater than the expected load of 50 megawatts, it is significantly less than the total class contract demand of 500 megawatts. Referring now to Table 4, if the availability of customer generation equipment increased to 95 per cent (5 per cent forced outage rate) the expected standby load would only be 25 megawatts with a contract demand of 500 megawatts. The chance of standby load in excess of 75 megawatts actually occurring on the utility system is less than 2 per cent under this scenario.

TABLE 3
STANDBY LOAD "STATES": TWENTY CUSTOMERS
(Ninety Per Cent Availability of Customer Equipment)

State	*Standby Load (Mw)*	*Probability**	*Cumulative Probability*
1	0	.1216	.1216
2	25	.2702	.3918
3	50	.2852	.6770
4	75	.1901	.8671
5	100	.0898	.9569
6	125	.0319	.9888
7	150	.0089	.9977
8	175	.0020	.9997
9	200	.0003	1.0000
10	225	0	1.0000
11	250	0	1.0000
12	275	0	1.0000
13	300	0	1.0000
14	325	0	1.0000
15	350	0	1.0000
16	375	0	1.0000
17	400	0	1.0000
18	425	0	1.0000
19	450	0	1.0000
20	475	0	1.0000
21	500	0	1.0000

Expected Standby Load — 50 megawatts.
Assumptions: Twenty identical 25-megawatt customers with .90 availability of customer generation equipment.

*Where "zero" probability is indicated, actual probability is less than .0001.

TABLE 4
STANDBY LOAD "STATES": TWENTY CUSTOMERS
(Ninety-five Per Cent Availability of Customer Equipment)

State	*Standby Load (Mw)*	*Probability**	*Cumulative Probability*
1	0	.3585	.3585
2	25	.3774	.7359
3	50	.1887	.9246
4	75	.0596	.9842
5	100	.0133	.9975
6	125	.0022	.9997
7	150	.0003	1.0000
8	175	0	1.0000
9	200	0	1.0000
10	225	0	1.0000
11	250	0	1.0000
12	275	0	1.0000
13	300	0	1.0000
14	325	0	1.0000
15	350	0	1.0000
16	375	0	1.0000
17	400	0	1.0000
18	425	0	1.0000
19	450	0	1.0000
20	475	0	1.0000
21	500	0	1.0000

Expected Standby Load — 25 megawatts.
Assumptions: Twenty identical 25-megawatt customers with .95 availability of customer generation equipment.

*Where "zero" probability is indicated, actual probability is less than .0001.

These results illustrate the potential loads that utilities may face from standby contract demand customers. Actual results would depend on the specific characteristics of the customers in the class; e.g., availability factors. Regardless of the class makeup, an analysis can be developed to estimate the potential loads on the utility system and the related costs of providing service. An understanding of the nature of standby loads will provide the information necessary for realistic and reasonable cost-of-service allocations and rate designs for standby service.

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

SURREBUTTAL TESTIMONY AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

ARKANSAS ELECTRIC ENERGY CONSUMERS

KENNEDY AND ASSOCIATES
ATLANTA, GEORGIA

MARCH 1988

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

SURREBUTTAL TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and address.

A. Stephen J. Baron, and my business address is Suite 475, 35 Glenlake Parkway, Atlanta, Georgia.

Q. Are you the same Stephen J. Baron who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I am responding to the rebuttal testimony of Arkansas Power & Light ("AP&L") Company witness Allen C. Hardy.

Q. In his Rebuttal Testimony, Alan C. Hardy asserts that you represent a "small special interest group of customers." Do you agree with Mr. Hardy's characterization of AEEC?

A. I certainly do not. AEEC includes about 25 of AP&L's largest industrial customers. AEEC members encompass the agricultural sector, the forest products industries of Arkansas, the chemicals industry and manufacturing. It is a broad-based group with support from all parts of the state included in AP&L's service territory.

Q. **Do you agree with Mr. Hardy's statement that most industrial customers would not support the idea of AP&L shifting the cost of standby service from cogenerators to other industrial customers?**

A. AEEC has always supported non-discriminatory rates based on cost of service. AEEC's position is consistent with the FERC's and APSC's regulations governing standby rates. These regulations require that standby rates "(1) shall be just and reasonable and in the public interest, and (2) shall not discriminate against cogenerators." (18 C.F.R. Section 292.305). As I point out in my opening testimony, AP&L's proposed rates fail to meet either of these criteria.

Q. **Would you please address the issue of the alleged "subsidy" raised by Mr. Hardy in his rebuttal testimony?**

A. Mr. Hardy contends that a "subsidy" currently exists to Rider M7 customers from other customers who do not use self-generation. The implication of Mr. Hardy's discussion in this portion of his testimony is that AP&L is trying to "right" this "wrong" which the Company has allowed to happen over the past few years. The proposal which I have made reflects a cost based methodology and one that is not discriminatory, unlike AP&L's proposal. Moreover, AP&L's

proposal would create substantial revenues to AP&L in excess of its cost of providing standby service.

Q. Do you believe that Mr. Hardy has adequately addressed your contention that AP&L failed to consider diversity in its own Rider M7 analysis?

A. No. Mr. Hardy's discussion of diversity does not address the questions and issues that I have raised in my testimony regarding the failure of AP&L to consider diversity. Mr. Hardy's analysis simply divides the total revenue requirements related to demand costs by the net Company capability on the system. This does not address in any way the diversity issue which I raised in my testimony and which is mandated by the FERC's and the Arkansas Commission's Cogeneration Rules. Mr. Hardy has simply ignored Section 3.5 of the Commission's Cogeneration Rules and Section 292.305(c)(1) of the FERC's rules which state that the rates for sales of back-up power "shall not be based upon an assumption (unless supported by factual data) that forced outages or reductions in electric output by qualifying facilities in an electric utility system will occur simultaneously or during the system peak, or both..." Mr. Hardy has assumed that forced outages will occur simultaneously. Mr. Hardy has submitted no data to support this assumption.

Q. Do you have any comments regarding Mr. Hardy's specific criticism of your rate analysis?

A. Mr. Hardy has revised my analysis to reflect three specific modifications. The first of these is inclusion of costs from the Grand Gulf Rider M-33. Unfortunately, in Mr. Hardy's analysis, he has incorrectly assumed that standby customers would pay the full amount of the Grand Gulf purchase power expenses, instead of the costs actually charged to AP&L's retail customers through Rider M-33. Apparently, Mr. Hardy believes that it would be reasonable to discriminate against standby customers in this manner; I do not agree. Accordingly, I have modified my analysis to reflect the M-33 costs actually charged to AP&L's customers. Baron Exhibit SJB-1 shows a revision to the calculation of the monthly production demand rate using the current Grand Gulf Rider M-33 costs. In addition, an adjustment has been made to remove the Grand Gulf portion of the capacity equalization payments from the production revenue requirements calculation. The net result of these two adjustments is to increase the monthly production demand rate to $10.38 from the previous $7.68/kW. Baron Exhibit SJB-2 shows the revised summary of proposed rates using this $10.38 monthly production demand rate. As can be seen, this results in a standby charge ranging from $1.18 to $3.10/kW demand per month.

Q. **What are your comments regarding Mr. Hardy's other suggested corrections to your analysis?**

A. The second issue raised by Mr. Hardy is the use of net Company capability in unitizing production revenue requirements. First of all, this is the same approach used by Mr. Hardy in his analysis. It does not, in and of itself recognize diversity. Diversity would be recognized if the sum of all customer maximum demands were used to unitize production revenue requirements. The difference between net Company capability and the sum of all the customer maximum demands is the concept of diversity which I was referring to in my analysis and which should be well known to AP&L. Therefore, it is not correct that load diversity was counted twice in my analysis.

The final issue raised by Mr. Hardy concerns the use of a 10% forced outage rate to develop the appropriate diversity level for calculating a standby rate. Mr. Hardy has not presented any evidence in his rebuttal which shows that it is inappropriate to use a 10% forced outage rate assumption, reflecting the very high level of diversity associated with serving standby load. Nor did I find in Mr. Hardy's rebuttal testimony a discussion of how he considered diversity of standby customers in the calculation of his proposed Rider M7. The application of a 10% forced outage rate to the production demand cost on the system is an appropriate methodology to recognize the expected contribution of standby customers to the loads on the AP&L system. This is a standard approach in both planning and cost allocation.

Mr. Hardy, in his rebuttal testimony, discusses the uncertainty and risks associated with standby customer loads as presented in Exhibit SJB-2 of my direct testimony. He fails to recognize in his presentation the concept of expected value and the fact that utilities plan for expected peak loads on their system. While it is possible that all residential customers theoretically might turn on all of their appliances at the identical instant in time, it is not likely that they will do so, and AP&L prudently plans accordingly for the expected contribution of these customers to its peak. Similarly, AP&L should plan for the expected contribution of standby load to its peak. Mr. Hardy's analysis, though correctly stating the statistical results from my exhibit, does not addresses the main issue raised in my testimony which recognizes that the diversity of standby load should be utilized in computing the cost of serving this customer class. This is the concept which has been incorporated into the Arkansas Public Service Commission cogeneration rules as well as the FERC's rules and the proposed M7 clearly violates the legal requirements of both this Commission and the FERC. Certainly with respect to maintenance power, the rate should reflect that this service can be scheduled in an off-peak period and thus should be priced on an interruptible basis. This point was recently recognized by the FERC in Docket No. RM88-6-000, issued March 18, 1988:

> **"Since maintenance power is, by definition, supplied only on a scheduled basis, in the absence of an appropriate existing rate schedule, construction of cost based rates should also be straightforward. Rate schedules for interruptible services should reflect the fact that additional generating facilities will typically not be required to meet interruptible demands.** (p. 82)

Q. Do you agree with Mr. Hardy's testimony at p. 5-6 that cogenerators should not be allowed to purchase interruptible standby services.

A. No. The Federal Energy Regulatory Commission (FERC) has recently reaffirmed that cogenerators must be provided the option of both firm or interruptible standby services. In Docket No. RM88-6-000 issued March 18, 1988, the FERC pointed out that its "rules obligate utilities to provide to QF's supplementary, maintenance and back-up power on both a firm and interruptible basis." (p.-75) Thus, Mr. Hardy's comments regarding the testimony of Staff Witness Benson are without merit. AP&L is required to offer interruptible service to cogenerators under rates set forth in tariffs. If a cogenerator is willing to purchase power under the terms and conditions applicable to interruptible service, the cogenerator must be provided that option.

Q. Did Mr. Hardy address your testimony (p. 15-16) regarding the discriminatory nature of the proposed Rider M7 as compared to AP&L's firm rate?

A. No. As I pointed out in my opening testimony, a firm customer pays a minimum bill of $2.57/kW when not taking power. AP&L's proposed Rider M7 has the perverse effect of penalizing standby customers with low forced outage rates more than those with high forced outage rates. If AP&L's rates are to be non-discriminatory, standby customers should be charged no more than the corresponding firm service.

Q. Does this complete your testimony?

A. Yes.

Stephen J. Baron

Stephen J. Baron

State of Georgia
County of Fulton

Subscribed and sworn to before me, a notary public in and for the State and County aforesaid.

My commission expires

MY COMMISSION EXPIRES SEPT. 12, 1988

This 23rd day of March 1988

Barbara J. Trojanowski

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

SURREBUTTAL EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

ARKANSAS ELECTRIC ENERGY CONSUMERS

KENNEDY AND ASSOCIATES
ATLANTA, GEORGIA

MARCH 1988

ARKANSAS POWER & LIGHT COMPANY
DEVELOPMENT OF STANDBY RATE

Monthly Production Demand Rate
Including Nuclear Capacity

		HARDY TESTIMONY	ADD BACK NUCLEAR CAPACITY	ADJUSTED
BEFORE TAX COST OF CAPITAL	CC	12.59%		12.59%
PRODUCTION PLANT RATIO	PPR	26.98%	32.02%	59.00%
PRODUCTION LABOR RATIO	PLR	24.70%	44.09%	68.79%
PRODUCTION PLANT IN SERVICE	PPLT	$918,358,752	$1,090,024,749	$2,008,383,501
PP DEPR RESERVE EX NUC DECOMM	PDR	271,329,856	232,978,437	504,308,293
AP&L SHARE COAL MINING EQUIP	CME	25,022,708		25,022,708
COAL MINING DEPR RES	CMEDR	2,362,875		2,362,875
GEN PLANT EX COAL MIN EQUIP	GPLT	56,059,181		56,059,181
GEN PLANT DEPR RESERVE	GDR	13,275,730		13,275,730
INTANGIBLE PLANT	INPLT	30,516,034		30,516,034
ACC AMORT OF INTANGIBLE PLANT	INDR	8,389,273		8,389,273
MATERIALS & SUPPLIES	MS	37,203,711		37,203,711
PREPAID TAXES & INSURANCE	PPT	4,837,231		4,837,231
PRODUCTION RATE BASE	PRB	713,725,649		1,603,096,694
DEMAND REL PRODUCTION O&M	POMD	32,534,954	94,483,676	127,018,630
FORECASTED INCR IN CPI-URBAN	CPIU	1.036		1.036
ANNUALIZED CAP EQUAL PAYMENTS	CAPEQ	(19,895,700)	(26,379,660)	(46,275,360)
ANNUALIZED ACC'T 555 (OTHER)	FPUR	4,721,544	157,768,371 *	162,489,915
CUSTOMER ACCOUNTING EXP	CA	19,579,941		19,579,941
A&G EXPENSE	AG	93,509,607		93,509,607
ANN. PROD DEPR EXP (EX DECOMM)	PDX	30,807,579	35,609,476	66,417,055
COAL MINING EQ DEPR EXPENSE	CMEDX	1,359,289		1,359,289
ANNUALIZED GEN PLT DEPR EXP	GDX	2,263,244		2,263,244
ANNUALIZED INT PLT AMORT EXP	INDX	3,915,045		3,915,045
OTHER TAX RATE	OTR	1.11%		1.11%
PRODUCTION RELATED EXPENSES	PXP	94,305,483		423,942,082
INCOME TAX COMPONENT	INCTAX	4,500,911		4,500,911
TOTAL PRODUCTION REVENUE REQUIREMENTS		185,377,888		628,427,493
NET COMPANY CAPABILITY	NSPKW	4,416,000	628,000	5,044,000
MONTHLY PRODUCTION DEMAND RATE	MPDR	$3.50		$10.38

* Source: M-33 Rider, 9/1/87 (139,767,000/.8859)

ARKANSAS POWER & LIGHT COMPANY
DEVELOPMENT OF STANDBY RATE

Summary Of Proposed Rates Under Service Options

PRODUCTION AND TRANSMISSION DEMAND RATES

Monthly Production Demand Rate	10.38
Monthly Transmission Demand Rate	1.13
Production And Transmission Coincidence Rate	10.00%

DISTRIBUTION DEMAND RATES (cumulative for specified voltage level)

Monthly Distribution Demand Rate At Transformation	0.48
Monthly Distribution Demand Rate At Primary	1.24
Monthly Distribution Demand Rate At Secondary	1.70

METERING VOLTAGE LEVEL LOSS FACTORS

Transmission Loss Factor	1.0286
Substation Loss Factor	1.0357
Primary Distribution Loss Factor	1.0481
Secondary Distribution Loss Factor	1.0886

DEMAND RATES FOR SERVICE OPTIONS

A	Transmission, metered at transmission	1.183919
B	Transmission, metered at substation	1.192090
C	Distribution, metered at transformation	1.689226
D	Distribution, metered at primary	2.506007
E	Distribution, metered at secondary	3.103598

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

TESTIMONY AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

ARKANSAS ELECTRIC ENERGY CONSUMERS

KENNEDY AND ASSOCIATES
ATLANTA, GEORGIA

MARCH 1988

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

DIRECT TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and address.

A. Stephen J. Baron, and my business address is Suite 475, 35 Glenlake Parkway, Atlanta, Georgia.

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

A. I am Vice President and Principal of Kennedy and Associates, a firm of utility rate, planning and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, and cost of service and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, the Attorney General of New Mexico, industrial consumer groups in ten states, and a rural electric cooperative.

Q. Please state your educational background.

A. I was graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974 I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics and public utility economics. My thesis was the development of an econometric model to forecast electricity sales in the State of Florida for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Would you please describe your professional experience?

A. I have over ten years experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning and economic analysis.

Following completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone and gas utilities as well as the preparation of cross examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for

Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal.

During the course of my career, I have provided consulting services to over 30 utility, industrial and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of Electrical World. My article on "Standby Electric Rates" was published in the November

8, 1984 issue of Public Utilities Fortnightly. In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Connecticut, Kentucky, Louisiana, Maine, Missouri, Florida, Arkansas, Georgia, North Carolina, New Jersey, West Virginia, Indiana, New York, Ohio, Pennsylvania and the Federal Energy Regulatory Commission. A list of my specific regulatory appearances can be found in Baron Exhibit SJB-1.

Q. **On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Arkansas Electric Energy Consumers ("AEEC"), a group of large industrial customers of the Arkansas Power and Light Company ("AP&L").

Q. **What is the purpose of your testimony?**

A. My testimony will address three specific areas which are appropriate for the Commission to consider in setting a standby electric rate. First, I will discuss some principles which I believe are appropriate for analyzing standby rates such as the M7 rider under consideration by the Commission in this docket. The next area that I will address in my testimony is a review of AP&L's proposed standby rate methodology. Finally, I will recommend a standby rate level which I believe the Commission should adopt in place of the Company's proposed Rider M7. AEEC's proposal is based on a probabilistic approach to developing standby rates and reflects a method which is based on cost of service principles, unlike AP&L's proposal.

DISCUSSION OF STANDBY RATE PRINCIPLES

Q. **Would you now discuss what you believe to be the appropriate basis for setting standby rates for QF's and other cogenerating and self-generating utility customers?**

A. The starting point for developing a standby rate is to examine the FERC regulations implementing the Public Utility Regulatory Policies Act of 1978. Section 292.305(c) states:

The rates for sales of back-up and maintenance power:

1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by qualifying facilities in an electric utility system will occur simultaneously, or during the system peak, or both; and

2) Shall take into account the extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities.

The Arkansas Public Service Commission has adopted this language in Part C of Section 3.5 of its own Cogeneration rules.

In addition, both the FERC (Section 292.305(a)) and the Arkansas Public Service Commission (Section 3.5(a)) state that rates for sales to qualifying facilities:

1) Shall be just and reasonable and in the public interest; and

2) Shall not discriminate against any qualifying facility compared with rates for sales to other customers served by the electric utility.

I believe that these rules, as adopted by the FERC and the Arkansas Commission, should form the foundation for the development of a standby rate. Using these rules as a guide, a properly constructed rate should reflect the cost of service incurred by the Company in providing service to a class or customer and should not discriminate against cogenerators compared to rates for other customers. The basic methodology and framework which I believe should be employed to set standby rates follows very closely the traditional methodology used by electric utilities, including AP&L, to set rates for traditional classes of service. The key factor in setting any rate, including a standby rate, is the recognition of the diversity of an individual customer with respect to all other loads on the system. For example, in setting residential rates, AP&L does not charge a residential customer for generation and transmission costs based on the maximum demand that customer places on AP&L's system at any given point in time. Typically, the residential customer may have a coincident peak demand (the peak demand of that customer coincident with the utility's system peak) of 3 kW. This same residential customer may use enough appliances in his household to produce a maximum non-coincident demand of 10 kW. However, this non-coincident peak does not occur simultaneously among all residential customers so that AP&L only "sees" loads of 3 kW on its system. AP&L does not build generation and transmission capacity for its customers based on the maximum amount of load that such a customer could theoretically place on its system at one time, but rather plans enough capacity to handle customer coincident loads. Similarly, customers are not charged based on this maximum load. Clearly, even if AP&L had a million residential customers each with a maximum demand of 10 kW, it would not have to construct 10 million kW (10,000 mW) of generating capacity to serve these customers if the average coincident load of these million residential customers never exceeded 3 kW. The Company would correctly size its system to meet a load of 3,000 mW (plus reserves) rather than the full potential load of 10,000 mW. This is the traditional concept of diversity which is recognized in the utility industry.

Q. **How does this diversity concept relate to the development of standby rates?**

A. The exact same principle applies. Standby customers require service to backup their own generating units when those units are forced out. There is only a relatively small probability that a cogenerator's equipment will be forced out. This is similar to the probability that a residential customer would use a particular appliance at the time of the Company's coincident peak. To carry the analogy further, it will be helpful to consider a large group of 1,000 kW cogenerators, each of which requires standby or backup service. These cogenerators, all of whom require a 1,000 kW of backup service, do not each place 1,000 kW of demand on the AP&L system at one point in time. Just the same as a residential customer does not turn all of his or her appliances on simultaneously, a group of cogenerators will not be forced out all at the same time. There is diversity in the random forced outages of cogenerator equipment. It is this diversity which must be considered in setting an appropriate cost based standby rate.

Clearly, AP&L or any other utility would not propose to construct generating capacity for the potential connected load on its system. Rather, it recognizes diversity among these loads. In a similar fashion, AP&L will not construct generating capacity to serve the total potential load of a standby cogeneration customer. Rather, it would recognize diversity among the standby customers in deciding the amount of generation, transmission and distribution capacity it must construct to serve these loads. Diversity is the key to this issue.

Q. How should an appropriate cost based standby rate be developed in recognition of this diversity concept?

A. Baron Exhibit SJB-2 is a copy of a Public Utilities Fortnightly article which I authored on this subject. It lays out some of these principles and discusses the implications for an appropriate cost based design of a standby rate as well as the appropriate recognition of these costs in a traditional utility rate filing. Since standby customers in reality are no different from any other customers, they can be treated as a separate rate class for the purposes of cost-of-service analysis and tariff design. An appropriate treatment of standby customers would involve the development of a reasonable probability estimate (diversity) of a typical standby customer actually placing load on a utility system. This diversity concept has been recognized by a number of state public service commissions in developing standby rates. The appropriate approach is to develop an estimate of the forced outages of the standby rate class as a group and use this estimate to cost out and ultimately develop an appropriate standby tariff. Once established, this forced outage or diversity value can be used to set the appropriate cost responsibility of standby customers for system revenue requirements. For example, if the typical standby customer has a forced outage rate (not including maintenance) of 10%, then it would be reasonable to assume that 10% of the total standby contract demand would be placed on the AP&L system at any given point in time. Applying this probability (10%) to the Company's unit cost of generation and transmission capacity would yield an appropriate reservation charge for a standby tariff.

Q. **Could you please discuss the concept of a reservation charge?**

A. A reservation charge is simply a payment which a standby customer would make each month to reserve a contracted amount of capacity (generation, transmission and distribution) in the event the customer actually requires such capacity. The payment is made whether or not such capacity is actually used. However, since all standby customers do not require backup service simultaneously as a result of independent random forced outages of generating equipment, the amount of capacity, and therefore the charge for the reservation, should be based on the probability that the customer will actually require standby capacity. This is equivalent to utilizing the forced outage rate of standby load together with the unit cost of generation, transmission and distribution capacity to set the reservation charge. The reservation charge thus covers the cost responsibility of a standby customer for capacity on the AP&L system.

Q. **How should energy sales be charged for when backup power is actually provided as a result of a customer forced outage?**

A. In a month when a standby customer actually demands energy from a utility, a reasonable basis for setting the power rate in that month is to charge the customer based on the existing firm service tariff, exclusive of the kW demand charge. Since the reservation charge represents a standby customer's payment for capacity amortized over months during which he actually uses standby or backup service as well as months when he does not use such service, it is inappropriate to charge a customer again during the months when backup service is actually used. As a result, a reasonable method would be to charge a customer based on the firm service tariff exclusive of the kW demand charge for the month. In addition, since some demand costs are collected through the energy charges of AP&L's commercial and industrial rates, standby customers would still pay some demand costs under this approach.

Q. **What is the appropriate basis for pricing maintenance power?**

A. Maintenance power, unlike standby or backup power, is typically scheduled ahead of time between the cogenerator and the utility. As such, the responsibility of a utility for constructing generation, transmission and distribution capacity to serve the maintenance load is not the same as is required for standby or backup power requirements. Given the fact that AP&L has proposed (reasonably so) to require maintenance power to be scheduled in advance, an appropriate rate for providing maintenance service to the standby customer would be the firm service rate normally in effect less the otherwise applicable demand charge. Since maintenance power can be scheduled in off peak periods during which time a maintenance customer's load would not require additional AP&L capacity, it is inappropriate to charge a customer a demand charge for maintenance power.

Q. **How do these concepts which you have just discussed compare to the provisions of the Arkansas Public Service Commission's cogeneration rules?**

A. Based on my review of the cogeneration rules in Section 3.5 - Rates for Sales, I believe that the concepts which I have laid out for the appropriate basis for a standby rate and a maintenance rate are similar to the views expressed by the Arkansas Public Service Commission.

The Commission's cogeneration rules implicitly recognize the diversity concept in the establishment of standby rates and also recognize that maintenance power, properly scheduled, does not impose the same types of cost as does unscheduled standby or backup power. As discussed below, AP&L's failure to take these factors into account in designing M7 clearly violates the Commission's rules.

DISCUSSION OF AP&L'S PROPOSED MODIFICATION TO RIDER M7

Q. Could you now discuss AP&L's proposal for modifying standby Rider M7?

A. AP&L's proposed methodology for developing a standby rate fails to incorporate any of the principles which I previously discussed. The proposed Rider M7 does not consider diversity or the probability that a standby customer will actually require backup power from AP&L. As such, it does not seem to be based on any logical theory or principle of rate design. AP&L is proposing to increase its Rider M7 by as much as 176% for some customers. This increase is punitive and not justified.

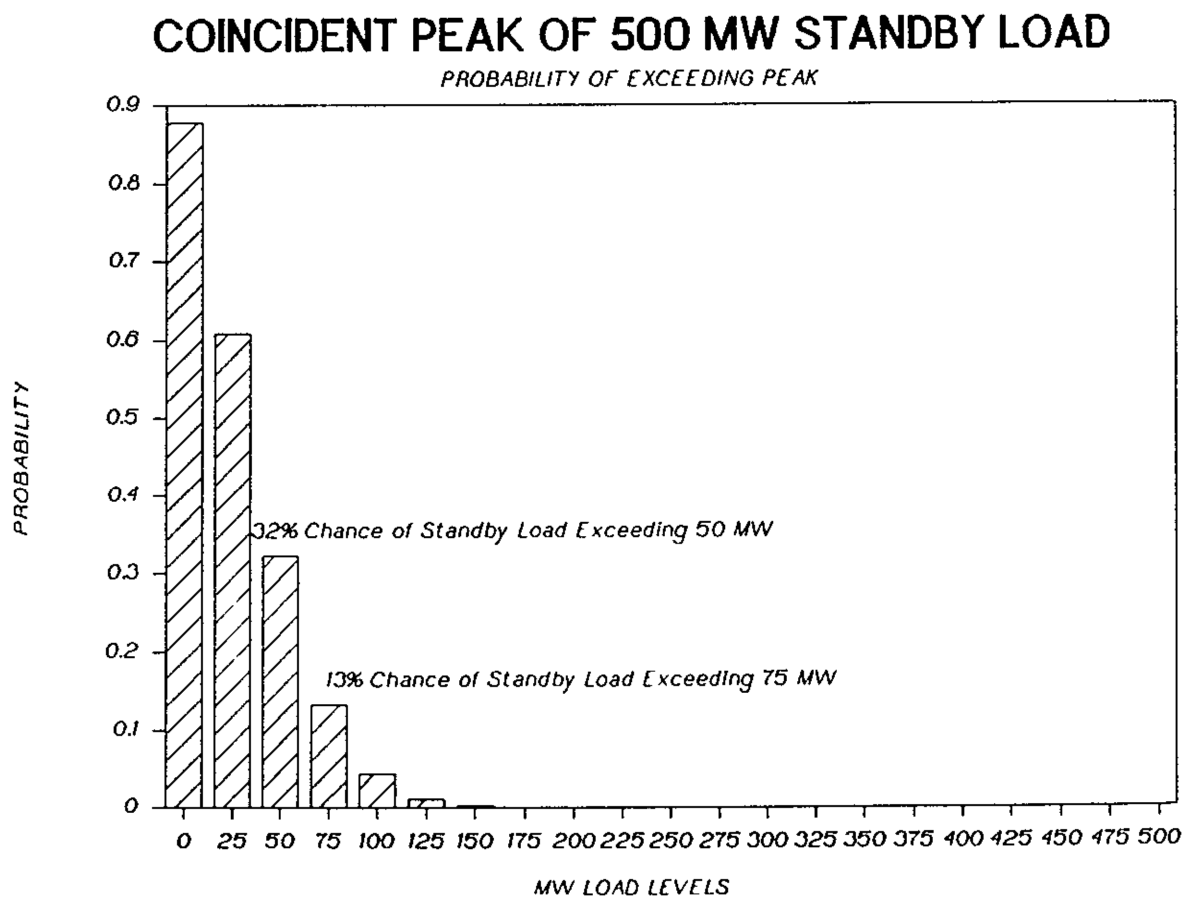
The basic AP&L approach was to take the unit cost of generation, transmission and distribution capacity on its system and remove the cost associated with nuclear capacity to establish a monthly reservation charge for standby customers. The removal of the nuclear capacity apparently was based on the assumption that nuclear generation operates at all times to serve firm load and therefore is not being used to serve standby customers. Beyond this explanation for why nuclear costs were removed from the analysis, there does not appear to be any rationale for AP&L's methodology. It would appear, based on AP&L's method, that the cost of coal capacity should also have been removed from the calculation. Since coal capacity is used as base load capacity on the Middle South and AP&L systems, it would follow (using AP&L's theory) that this capacity does not serve standby load either.

Needless to say, however, removing the coal capacity from the AP&L cost calculations would simply improve upon the Company's own theory. It would not correct the defects in the Company's methodology which fails to recognize diversity and the forced outages of standby customer equipment as required by the Arkansas Commission's cogeneration rules. It would however, substantially reduce the Company's proposed standby charge.

AP&L's methodology basically assumes that the Company must construct generation, transmission and distribution capacity to serve the full connected load of standby customers, though the Company would not construct nuclear capacity to do so. Therefore, AP&L proposes to charge standby customers a reservation charge based on the full unit cost (excepting nuclear costs) of providing 100% firm service to these customers even though the Company realizes that it need not construct capacity to provide for the full connected load of such customers. This is clearly discriminatory and should be rejected by the Arkansas Public Service Commission. It does not give any recognition to the appropriate cost structure of serving standby customers and violates the Commission's own rules for the development of standby rates.

Q. Can you provide an illustration of the unreasonableness of the Company's method?

A. Yes. Using the example shown in Table 3 on page 3 of 3 of Baron Exhibit SJB-2, I have developed a graph of the probabilities that a group of standby customers would place varying amounts of load on a utility system. In this example, it is assumed that there are 20 standby customers each of whom have a load or standby contract demand of 25 mW and a forced outage rate of 10%. The total standby load on the utility system is thus <u>500 mW</u>.



However, as can be seen from the graph above, there is only a 32% chance that the 500 mW of standby contract demand will exceed 50 mW and only a 13% chance that it will exceed 75 mW. AP&L's method would assume that it must serve all 500 mW of contract load, despite the fact that there is almost "0" chance that the load could ever exceed 150 mW, under a 10% forced outage rate assumption.

Q. **Do you believe that AP&L's proposed standby rate is discriminatory?**

A. Yes. The Company is effectively discriminating against standby customers by failing to recognize diversity among these loads despite the recognition of diversity for other customer classes. Simply removing the cost of nuclear capacity does not solve the problem of AP&L's failure to recognize diversity.

Since AP&L does recognize diversity and coincidence in designing its firm retail rates for other customers, the M7 rider clearly discriminatory against standby customers. The Company's proposal should be rejected by the Commission.

Q. **Could a customer under AP&L's proposed Rider M7 pay a higher charge than under the Company's firm service tariffs for the same service?**

A. Yes. Assume a hypothetical standby customer with a 1000 kW contract demand requires standby supplemental energy for 10% of the year due to forced outages. Further assume that all of these outages occur in 4 of AP&L's winter period months (standby supplemental energy is required during some hours in each of 4 winter months).

For a secondary service customer, AP&L's Rider M7 requires a $6.90 per kW monthly charge for each month in which no standby power is required (8 months) plus the Large General Service (LGS) demand charge of $8.53 per kW for each of the 4 winter months during which standby power is actually taken. For a 1000 kW load, the annual demand charges would be $89,320.

If the same customer (1000 kW, 10% load factor) took the identical service under AP&L's Large General Service rate schedule (instead of Rider M7), the customer would pay a minimum bill of $2.57 per kW for the 8 months during which no power was taken and $8.53 per kW during the 4 winter months when power was actually used. The annual charges under rate LGS would be $54,680.[1]

In this example, a customer on AP&L's Rider M7 would pay $34,640 per year more than an identical customer on rate LGS. This 63% penalty is clearly discriminatory to cogenerators.

---

[1] During the 4 winter months there would be identical customer and energy charges for both Rider M7 and rate LGS, so these charges were not included.

AEEC'S PROPOSAL

Q. Could you now discuss AEEC's proposal for a standby tariff?

A. As I discussed previously, the basic approach which I believe to be appropriate for developing a standby tariff is to recognize the diversity among standby customers. This is equivalent to developing an estimate for the forced outage rate of standby customer generating equipment. Once this forced outage or diversity level has been identified, it is a relatively simple matter to develop an appropriate standby rate. In applying this approach to AP&L standby rates, the first step is to add back the nuclear capacity associated costs which were removed by AP&L in the development of its proposed M7 rider. Baron Exhibit SJB-3 shows these calculations, which produce a monthly production demand rate of $7.68 with nuclear capacity costs added in. This $7.68 monthly production demand rate is the appropriate starting point to develop a standby rate. AP&L's use of a $3.50, non-nuclear, capacity charge does not have any cost basis. For the purposes of developing AEEC's proposed standby rate, I have relied on AP&L's demand costs for transmission and distribution service which are contained in the Company's study in this proceeding. The major change which I propose to make to the Company's overall analysis is to recognize diversity and the probability of forced outages among standby customers.

Q. What forced outage rate have you used for standby customer generating equipment in developing AEEC's proposed standby rate?

A. This is perhaps the most difficult question to address in developing a standby rate. I have reviewed testimony presented in other state proceedings on this matter and have contacted equipment vendors and the American Gas Association regarding studies or analyses which they may have performed to estimate the availability rate of cogeneration equipment. A recent case in Florida (Docket No. 850673-EU) relied on a forced outage rate of 10% to develop standby rate principles for use by Florida electric utilities.

I requested AP&L to provide such data for its standby customers and the Company was unable to so. This is understandable in light of the fact that the issue of diversity had not previously been encountered in the development of AP&L's standby Rider M7. The Rider appears to have been based previously on the minimum demand charge in the Company's firm service rate schedules. What I propose in this proceeding to establish a reasonable cost based and non-discriminatory standby rate is the utilization of a 10% forced outage rate assumption for the design of the rate. Though a specific individual standby customer may have a lower or higher forced outage rate, a 10% rate (as adopted by the Florida Public Service Commission) is a reasonable value to use to establish the rate. Given the fact that there are relatively few customers who actually take standby service at the present time, the revenue impact on AP&L from variations on this assumption would be insignificant. However, beginning with the implementation by the Commission of this new standby rate, I recommend that AP&L record, through magnetic tape metering or other means, the load characteristics of its standby customers. The Company would be in a position at some future point in time to present to this Commission factual evidence supporting an appropriate forced outage rate or availability rate for standby load on the AP&L system. With the presentation of this actual data, Rider M7 could then be modified to reflect the forced outage rate on the AP&L system. To arrive at a reasonable estimate of the forced outage rate for AP&L standby customers, I recommend a minimum of 24 months of data collection before such a filing by AP&L is presented to the Commission.

I believe that this proposal will provide the most reasonable means to establish cost based, non-discriminatory standby rates on the AP&L system. In the interim period between now and the time AP&L completes its data collection effort, the use of a 10% forced outage rate is a reasonable basis for establishing the Rider M7 rate level.

The estimation of an appropriate forced outage rate or availability rate for standby generating customers on the AP&L system is clearly an important element in the establishment of a cost based standby rate. However, the fact that AP&L has not had the opportunity to perform a detailed statistical analysis to measure the forced outage rate of standby customer generation on its system should not preclude this Commission from adopting a methodology which utilizes these values in the development of standby tariffs. The Commission's own rules (adopted from FERC rules) clearly recognizes the importance and reasonableness of diversity among customer loads in the establishment of a standby tariff.

Q. Do you have any specific evidence regarding expected forced outage rates for cogeneration equipment?

A. Yes. Baron Exhibits SJB-4 and SJB-5 contain unit characteristic data (including availability) for two types of generating units which are similar to those used in some cogeneration facilities. The first type of unit (SJB-4) is a conventional combined cycle unit. Its equivalent unplanned outage rate is 4.9%. Exhibit SJB-5 contains unit characteristic data for a wood fired power plant. The equivalent unplanned outage rate for a wood burning facility is shown to be 8%. These data have been reproduced from EPRI's December 1986 Technical Assessment Guide (TAG).

The forced outage rates for these two types of equipment are much less than the 10% value which I have employed in developing a standby rate level.

Q. Do you believe that it is appropriate to utilize the same diversity level for distribution related costs as for transmission and generation related costs?

A. The 10% forced outage rate assumption which I have adopted to design a standby rate recognizes the probability of coincidence among standby customers with respect to the joint demand they would place on AP&L's system, whether generation, transmission or distribution. With respect to generation and transmission facilities, it is reasonable to apply this coincidence factor to the unit cost of such facilities to arrive at a standby charge.

However, though the probability of a standby customer actually requiring the use of distribution facilities may only be 10%, the risk applicable to distribution facilities is greater due to the lower level of load. Diversity on the distribution system is simply lower than on the generation and transmission system. This relationship is recognized in cost allocation studies which assign distribution costs based on class non-coincident loads and customer non-coincident loads. As a result, I believe that it is reasonable to assign the full unit cost of distribution facilities in the design of Rider M7 at this time. However, in the future, AP&L should provide an analysis of the diversity of standby loads on its distribution system along with the analysis of diversity on the generation and transmission system. If there is significant diversity among standby customers (relative to other distribution customers), then there should be a reduction in the distribution cost component of Rider M7. However, for the purposes of my recommendation in this proceeding, I have utilized the full unit cost of distribution capacity.

Q. **Have you developed a standby rate based on your 10% forced outage rate assumption?**

A. Yes. Baron Exhibit SJB-6 shows the results of an analysis using AP&L's data (12 months ended December 1986) which has been adjusted to reflect diversity among standby customers with a 10% forced outage rate. The forced outage rate of 10% is simply multiplied times the unit cost of generation and transmission capacity to arrive at the appropriate rate level for each type of service. Distribution costs are identical to those used by AP&L. All costs are adjusted for losses. The recommended rates are as follows:

a) Service is delivered and metered at 115,000 volts or greater.

$.906 per kW of Standby Capacity

b) Service is delivered at 115,000 volts or greater and metered at a lower voltage.

$.912 per kW of Standby Capacity

c) Service is delivered and metered at voltages of 13,800y/7,960 or greater but less than 115,000 volts and customer takes service at the substation.

$1.410 per kW of Standby Capacity

d) Service is delivered and metered at voltages of 13,8000y/7,960 or greater but less than 115,000 volts and customer takes service from the primary distribution system.

$2.223 per kW of Standby Capacity

e) Service is delivered and metered at voltages of less than 13,800y/7,960.

$2.810 per kW of Standby Capacity

Q. **Do you have any additional recommended changes in the Company's proposed Rider M7?**

A. Yes. As indicated previously, I believe that it is inappropriate to charge a standby customer a demand charge during the month in which such customer actually takes supplemental power from AP&L, when the customer is also paying a standby charge. The purpose of the reservation charge is to pay for capacity each month regardless of whether or not it is actually used. Under

AP&L's proposal, a customer would be required to pay both the standby charge to reserve capacity when no power is taken and also pay a demand charge during the month in which power is actually taken. I believe that this is double counting and should not be incorporated into the standby tariff. It is appropriate and reasonable to rely on a firm service rate schedule for the purpose of pricing supplemental power during the month in which it is actually taken. However, since the standby charge will pay for the appropriate capacity cost incurred by AP&L as a result of standby load, it is not appropriate to then charge standby customers the demand charge associated with the firm tariff under which supplemental power is taken. This provision of AP&L's proposed Rider M7 discriminates against standby customers and should be rejected.

Finally, even if a demand charge were to be included in the rate for supplemental power, AP&L incorrectly proposes to charge standby power customers a demand charge during the month in which maintenance power is actually taken. Given the fact that maintenance power is scheduled with the utility, it is reasonable to exclude the demand charge from the charge for maintenance power provisions in Rider M7. Under the terms of AP&L's proposed Rider M7, a customer must provide at least three months written notice prior to a planned maintenance activity. Given this three months notice provision, it seems reasonable that such a maintenance customer should not have to pay a demand charge which reflects the cost of capacity on the AP&L system. This is especially true since the proposed M7 requires that maintenance power be taken only during AP&L's off-peak season. Finally, since the energy charge in AP&L's rates includes a substantial amount of fixed cost, the elimination of the applicability of the fixed kW demand charge from the maintenance power tariff would not totally eliminate demand costs paid by such customers. As a result, maintenance customers would still be providing some portion of the fixed cost associated with capacity on the AP&L system even if there were no demand charge for maintenance power.

Q. Are there any other provisions in AP&L's proposed Rider M7 which are discriminatory?

A. Yes. AP&L's rate schedules applicable to demand-metered customers contain a minimum charge based upon a 12 month ratchet. The monthly charge is based on the customer's highest demand established during the past 12 months. By contrast, AP&L's proposed Rider M7 contains a ratchet that bases the monthly standby rate on the customer's highest demand for the entire contract period or three years. This is clearly in violation of both the FERC's and the Arkansas Public Service Commission's rules on non-discrimination.

Q. Does that complete your testimony?

A. Yes.

Stephen J. Baron

State of Georgia
County of Fulton

Subscribed and sworn to before me, a notary public in and for the State and County aforesaid.

My commission expires

MY COMMISSION EXPIRES SEPT. 12, 1988

This 10th day of March 1988

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

DOCKET NO. 87-183-TF

ARKANSAS POWER AND LIGHT COMPANY

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

ARKANSAS ELECTRIC ENERGY CONSUMERS

KENNEDY AND ASSOCIATES
ATLANTA, GEORGIA

MARCH 1988

Kennedy and Associates
Expert Testimony Appearances
of
Stephen J. Baron
As of January 1988

Date	Case No.	Jurisdict.	Party	Utility	Subject Matter	Cross Exam
4/81	203(B)	Kentucky	Louisville Gas & Electric	Louisville Gas & Electric	Cost of service.	Yes
4/81	ER-81-42	Missouri	Kansas City Power & Light	Kansas City P&L	Forecasting	Yes
6/81	U-1933	Arizona	Arizona Corp. Commission	Tuscon Electric	Forecasting planning.	No
2/84	8924	Kentucky	Airco Carbide	Louisville Gas & Electric	Revenue requirements, cost of service, forecasting, weather normalization.	Yes
5/84	830470-EI	Florida	Fla. Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs load & capacity balance & & reserve margin, Diversification of utility.	Yes
10/84	84-199-U	Arkansas	Ark. Electric Energy Consumers	Arkansas P&L	Cost allocation and rate design.	No
11/84	R-842651	Pennsylvania	Lehigh Valley Power Committee	Pennsylvania P&L	Interruptible rates, excess capacity, and phase-in	Yes
2/85	I-840381	Pennsylvania	Phil. Area Ind. Energy Users' Group	Philadelphia Electric Company	Load and energy forecast	Yes
3/85	9243	Kentucky	Alcan Aluminum Corp. et. al.	LG&E	Economics of completing fossil generating unit.	Yes

Kennedy and Associates
Expert Testimony Appearances
of
Stephen J. Baron
As of January 1988

Date	Case No.	Jurisdict.	Party	Utility	Subject Matter	Cross Exam
3/85	3498-U	Georgia	Attorney General	Ga. Power Co.	Load and energy forecasting, generation planning economics	Yes
3/85	R-842651	Pennsylvania	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.	Yes
5/85	84-249	Arkansas	Arkansas Electric Energy Consumers	Arkansas P&L	Cost of service, rate design return multipliers	Yes
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost of service, Rate Design	Yes
6/85	84-768-E-42T	West Virginia	West Virginia Industrial Intervenors	Monongahela Power	Generation planning economics, prudence of a pumped storage hydro unit.	Yes
6/85	E-7 Sub 391	North Carolina	Carolina Industrials (CIGFUR III)	Duke Power Company	Cost of Service, Rate Design, Interruptible rate design	Yes
7/85	29046	New York	Industrial Energy Users Association	Orange and Rockland Utilities	Cost of service, Rate Design	Yes
10/85	85-043-U	Arkansas	Arkansas Gas Consumers	Arkla, Inc.	Regulatory Policy, Gas Cost of Service, Rate Design	Settled
10/85	85-63	Maine	Airco Industrial Gases	Central MA. Power Co.	Feasibility of interruptible rates, avoided cost	Yes

Kennedy and Associates
Expert Testimony Appearances
of
Stephen J. Baron
As of January 1988

Date	Case No.	Jurisdict.	Party	Utility	Subject Matter	Cross Exam
12/85	ER-8507698	New Jersey	Air Products and Chemicals	Jersey Central P & L	Rate Design	Yes
3/85	R-850220	Pennsylvania	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal Reserve Margins, Prudence, Off-System Sales Guarantee Plan	Yes
2/86	R-850220	Pennsylvania	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal Reserve Margins, Prudence, Off-System Sales Guarantee Plan	Yes
3/86	85-299U	Arkansas	Arkansas Electric Energy Consumers	Arkansas Power & Light	Cost of Service, Rate Design Revenue Distribution	Yes
3/86	85-726-EL-AIR	Ohio	Industrial Electric Consumers Group	Ohio Power Company	Cost of Service, Rate Design Interruptible Rates	Settled
5/86	86-081-E-GI	West Virginia	West Virginia Energy Users Group	Monogahela Power Company	Generation planning economics, prudence of a pumped storage hydro unit	Yes
8/86	E-7 Sub 408	North Carolina	Carolina Industrial Energy Consumers	Duke Power Company	Cost of Service, Rate Design, Interruptible Rates	Yes
10/86	U-17378	Louisiana	Louisiana Public Service Commission	Gulf States Utilities	Excess Capacity, Economic Analysis of Purchased Power	Yes

Kennedy and Associates
Expert Testimony Appearances
of
Stephen J. Baron
As of January 1988

Date	Case No.	Jurisdict.	Party	Utility	Subject Matter	Cross Exam
12/86	38063	Indiana	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible Rates	Yes
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission	Gulf States Utilities Southern Company	Cost/Benefit Analysis of Unit Power Sales Contract	Yes
4/87	U-17282	Louisiana	Louisiana Public Service Commission Staff	Gulf States Utilities	Load Forecasting and Imprudence damages Riverbend Nuclear unit	Yes
5/87	87-023-E-C	West Virginia	Airco Industrial Gases	Monongahela Power	Interruptible Rates	Yes
5/87	87-072-E-G1	West Virginia	West Virginia Energy Users Group	Monongahela Power	Analyze Mon Power's fuel filing & examine the reasonableness of MP's claims	Yes
5/87	9781	Kentucky	Kentucky Industrial Energy Consumers	Louisville G&E	Analysis of impact of 1986 Tax Reform Act	Yes
6/87	3673-U	Georgia	Georgia Public Service Comm.	Georgia Power Company	Economic Prudence Evaluation of Vogtle Nuclear unit- Load Forecasting, Planning	Yes
6/87	U-17282	Louisiana	LPSC	Gulf States Utilities	Phase-in plan for Riverbend Nuclear unit	Yes

Kennedy and Associates
Expert Testimony Appearances
of
Stephen J. Baron
As of January 1988

Date	Case No.	Jurisdict.	Party	Utility	Subject Matter	Cross Exam
7/87	85-10-22	Connecticut	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Methodology for refunding rate moderation fund	Yes
8/87	3673-U	Georgia	Georgia Public Service Comm.	Georgia Power Company	Test year sales and revenue forecast	Yes
9/87	R-850220	Pennsylvania	West Penn Power Industrial Intervenors	West Penn Power	Excess Capacity, Reliability of Generating System	Yes
10/87	R-870651	Pennsylvania	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible Rate, Cost-of-Service, Revenue Allocation, Rate Design	Yes
10/87	E-015/ GR-87-223	Minnesota	Taconite	Minnesota Intervenors Light	Excess Capacity, Power and Cost-of-Service, Rate Design	Yes
10/87	8702-EI	Florida	Occidental Chemical Corp.	Florida Power Corp.	Revenue Forecasting Weather Normalization	Settled
12/87	87-07-01	Connecticut	Conn. Industrial Energy Consumers	Connecticut Light & Power	Excess Capacity, Nuclear Plant Phase-in	Yes

A Realistic Approach to Standby Electric Rates

By STEPHEN J. BARON

In setting rates for backup service to cogenerators and other customers having independent sources of generation, electric utilities have relied heavily upon traditional principles of rate design. Standby contract demand charges typically fail to take into account the probability of power actually being needed. The approach to setting rates introduced in this article considers the specific characteristics of standby customers and facilitates cost-of-service analysis and system planning for electric utilities.

THE rapid increase in cogenerated and self-generated electric power by industrial firms and large institutions in the 1980s has created a need to reexamine the fundamentals of standby electric rates. Standby power is usually provided by electric utilities to nonutility customers who have their own indigenous sources of electric generation. It is generally used to provide backup service in the case of planned maintenance of the customer's own generation or emergency power in the case of a forced outage. Since there have been only a relatively small number of nonutility electric producers in the past, standby power has not been a significant utility service. For this reason, the development of standby electric rates has received little attention from regulators and potential users.

By 1980, standby rate design was no longer an obscure issue. In almost all cases, cogenerators and self-generators must rely on standby power as part of their overall electric production operation. From the utility's viewpoint, there are certain (albeit difficult to quantify) costs associated with providing this backup demand and energy, as standby power is sometimes referred to. The major issue of standby rate design is the cost basis for developing the rate.

Stephen J. Baron is a vice president and principal with Kennedy and Associates, a firm of utility rate, economic, and planning consultants located in Altanta, Georgia. Earlier, he was a manager with the Utility Regulatory and Advisory Services Group of Coopers & Lybrand and was a vice president of energy management services with Ebasco Business Consulting Company. **Mr. Baron** has a BA degree and an MA degree in economics, both from the University of Florida.

In general, the traditional approaches to standby electric rate design have employed contract demand charges for each kilowatt of standby load. This contract demand charge is paid monthly, whether or not the standby power is actually utilized and represents a reservation charge for the capacity necessary to serve the standby load. Energy charges are normally based on current general service or large industrial rates and are only initiated and billed when standby power is actually consumed. In other words, there is no reservation charge for energy, only for capacity. On the surface, this seems to be a reasonable approach. A fixed reservation charge for a contract amount of standby capacity and an energy charge which only takes effect when standby power is used. Controversy surrounding standby electric rate design tends to be associated with: (1) the amount of the contract demand charge, and (2) the approach used to compute the contract demand.

Charges for standby contract demand are typically based on the demand charge in the standard large general service rate and, in many instances, are actually identical to that demand charge. In most cases, formal cost studies are not used to develop the cost of standby power. Given the lack of a cost study, the best proxy for estimating the cost of standby contract demand is the existing firm service rate. One reason for this lack of cost analysis is that traditional cost allocation techniques do not recognize the costs associated with providing standby power. Regardless of the cost allocation technique employed, it is quite conceivable that during a given test year only minimal standby power was provided to contract users. For example, standby power may have been provided for planned maintenance and some minor forced outages, all of which occurred during off-peak periods. Using traditional cost allocation techniques, the standby rate class would be allocated little or no demand-related costs. As a result, utilities have tended not to use cost studies in standby rate design.

The second aspect of the standby rate issue, and perhaps the most controversial, is the determination of the contract demand. Contract demand is usually defined as the maximum potential amount of reserve power (kilowatts) required, regardless of the probability of usage. If an industrial cogenerator or self-generator generates 50 megawatts of power and requires a constant firm load for process use of at least half that amount (25 megawatts), the customer might contract for 25 megawatts of standby power. Controversy on the computation of contract demand stems from differences in the probability that standby power will be required on the part of the user. Under most standby rates, the charges for 25 megawatts of contract standby power would be the same regardless of the probability that the demand would actually be placed on the utility system.

An example may be helpful. Assume that a utility has two industrial self-generators, each of which has 25 megawatts of contract standby demand. Now assume that Customer 1 has a production plant with an average availability of 90 per cent (excluding planned maintenance from the analysis). This customer's production plant would be forced out 10 per cent of the time and rely on the utility for backup power during these periods. The second customer is assumed to have an availability of 99 per cent, requiring standby power from the utility only one per cent of the time (again ignoring planned maintenance). Since the standby rate design does not reflect the probability of standby power actually being required, each of the customers would pay the same charges for their respective 25 megawatts of contract demand.

In cases where the contract demand charge is the same as the firm service demand charge, this would suggest that 25 megawatts of system production capacity has been reserved for standby use by each customer, regardless of the probability that it will actually be needed. In fact, the expected load on the utility from Customer 1 is the 10 per cent forced outage rate times the contract demand of 25 megawatts, an expected load of 2.5 megawatts. For Customer 2, the expected load on the utility is .25 megawatt. At any given time (including peak periods), the utility can expect 2.75 megawatts of load from these two customers despite the fact that they have actually contracted for 50 megawatts of contract demand. Table 1 illustrates these calculations. If we increase the example to 50 or 100 co- or self-generators, this concept of expected load would appear to be even more realistic. In fact, the utility could actually reserve and plan for capacity to meet the expected standby power requirements of the total group. (It should be noted that the analysis becomes more complicated if the random forced outages are not independent of time of day or season of the year.)

Use of a probabilistic approach to standby rate design has a number of implications for both cost-of-service analysis and system planning. Under a probabilistic

TABLE 1
CALCULATION OF EXPECTED LOADS

Customer 1:

	25 Mw	Standby Load Requirement
×	.10	Forced Outage Rate
	2.50 Mw	Expected Load

Customer 2:

	25 Mw	Standby Load Requirement
×	.01	Forced Outage Rate
	.25 Mw	Expected Load

Total Expected Load:

	2.5 Mw
+	.25
	2.75 Mw*

*Forced outages are assumed independent and thus expected loads are additive.

approach, a standby rate class can be viewed as a firm power rate class for cost allocation purposes. If it is assumed that random forced outages on customer equipment are time-invariant, then the concept of identifying an expected value of standby rate class load would easily fit into existing cost allocation frameworks. A similar approach can be used for planning purposes. The expected value of the standby rate class load can be added to load forecasts at 100 per cent load factor.

In actual practice, a realistic rate design could be based on the characteristics of the entire standby rate class rather than on the behavior of any particular customer. This approach has a direct analogy to the techniques employed in traditional firm service rate design — for example, the assumption that all customers have an average class coincidence factor in a large general service rate, despite the fact that the actual relationship between maximum demand and demand at the time of the class peak may vary widely among customers within the class.

Using a class as the basis for standby rate design requires the development of an expected profile of all standby loads, with explicit consideration given to the probability distribution of the individual customer requirements. A basic premise in this approach is that standby loads need only be considered on an expected basis for planning and thus should be costed in a similar manner. Is this realistic? The answer depends on the size of the standby rate class and on the concept of diversity. Using a two-customer example (Table 2), all

TABLE 2
EXAMPLE — STANDBY LOAD "STATES": TWO CUSTOMERS

State	*Standby Load Requirements*	*Probability*
1	0	.81
2	25	.18
3	50	.01
		1.000

Expected Standby Load — five megawatts.
Assumptions: Customer 1 — 25 megawatts, .90 availability of customer generation equipment.
Customer 2 — 25 megawatts, .90 availability of customer generation equipment.

of the possible states can be computed with their associated probabilities of occurrence. (Note: Both customers in this example are assumed to have 90 per cent availability of customer generation equipment.) These probability states represent the various standby load requirements faced by a hypothetical utility at any point in time.

From Table 2, there is an 18 per cent chance that the standby requirements will be 25 megawatts even though on average the load will only be five megawatts. Considering this risk, can a utility plan to meet the expected load? The answer depends on the planning criteria of the utility. However, it seems reasonable that most utilities would not plan to meet the total potential load of 50 megawatts which only has a one per cent chance of occurring.

As more standby customers are added to the rate class, the planning risk of meeting the expected load becomes smaller. Table 3 illustrates a probability distribution of standby load with twenty customers, each having a 25-megawatt requirement with a 90 per cent availability of customer generation equipment. The expected value of the standby load is 50 megawatts. From the distribution

TABLE 3
STANDBY LOAD "STATES": TWENTY CUSTOMERS
(Ninety Per Cent Availability of Customer Equipment)

State	*Standby Load (Mw)*	*Probability**	*Cumulative Probability*
1	0	.1216	.1216
2	25	.2702	.3918
3	50	.2852	.6770
4	75	.1901	.8671
5	100	.0898	.9569
6	125	.0319	.9888
7	150	.0089	.9977
8	175	.0020	.9997
9	200	.0003	1.0000
10	225	0	1.0000
11	250	0	1.0000
12	275	0	1.0000
13	300	0	1.0000
14	325	0	1.0000
15	350	0	1.0000
16	375	0	1.0000
17	400	0	1.0000
18	425	0	1.0000
19	450	0	1.0000
20	475	0	1.0000
21	500	0	1.0000

Expected Standby Load — 50 megawatts.
Assumptions: Twenty identical 25-megawatt customers with .90 availability of customer generation equipment.

*Where "zero" probability is indicated, actual probability is less than .0001.

in Table 3, there is only a one per cent chance of the standby load being greater than 125 megawatts at any point in time. Though this is greater than the expected load of 50 megawatts, it is significantly less than the total class contract demand of 500 megawatts. Referring now to Table 4, if the availability of customer generation equipment increased to 95 per cent (5 per cent forced outage rate) the expected standby load would only be 25 megawatts with a contract demand of 500 megawatts. The chance of standby load in excess of 75 megawatts actually occurring on the utility system is less than 2 per cent under this scenario.

TABLE 4
STANDBY LOAD "STATES": TWENTY CUSTOMERS
(Ninety-five Per Cent Availability of Customer Equipment)

State	*Standby Load (Mw)*	*Probability**	*Cumulative Probability*
1	0	.3585	.3585
2	25	.3774	.7359
3	50	.1887	.9246
4	75	.0596	.9842
5	100	.0133	.9975
6	125	.0022	.9997
7	150	.0003	1.0000
8	175	0	1.0000
9	200	0	1.0000
10	225	0	1.0000
11	250	0	1.0000
12	275	0	1.0000
13	300	0	1.0000
14	325	0	1.0000
15	350	0	1.0000
16	375	0	1.0000
17	400	0	1.0000
18	425	0	1.0000
19	450	0	1.0000
20	475	0	1.0000
21	500	0	1.0000

Expected Standby Load — 25 megawatts.
Assumptions: Twenty identical 25-megawatt customers with .95 availability of customer generation equipment.

*Where "zero" probability is indicated, actual probability is less than .0001.

These results illustrate the potential loads that utilities may face from standby contract demand customers. Actual results would depend on the specific characteristics of the customers in the class; e.g., availability factors. Regardless of the class makeup, an analysis can be developed to estimate the potential loads on the utility system and the related costs of providing service. An understanding of the nature of standby loads will provide the information necessary for realistic and reasonable cost-of-service allocations and rate designs for standby service.

ARKANSAS POWER & LIGHT COMPANY
DEVELOPMENT OF STANDBY RATE

Monthly Production Demand Rate
Including Nuclear Capacity

		HARDY TESTIMONY	ADD BACK NUCLEAR CAPACITY	ADJUSTED
BEFORE TAX COST OF CAPITAL	CC	12.59%		12.59%
PRODUCTION PLANT RATIO	PPR	26.98%	32.02%	59.00%
PRODUCTION LABOR RATIO	PLR	24.70%	44.09%	68.79%
PRODUCTION PLANT IN SERVICE	PPLT	$918,358,752	$1,090,024,749	$2,008,383,501
PP DEPR RESERVE EX NUC DECOMM	PDR	271,329,856	232,978,437	504,308,293
AP&L SHARE COAL MINING EQUIP	CME	25,022,708		25,022,708
COAL MINING DEPR RES	CMEDR	2,362,875		2,362,875
GEN PLANT EX COAL MIN EQUIP	GPLT	56,059,181		56,059,181
GEN PLANT DEPR RESERVE	GDR	13,275,730		13,275,730
INTANGIBLE PLANT	INPLT	30,516,034		30,516,034
ACC AMORT OF INTANGIBLE PLANT	INDR	8,389,273		8,389,273
MATERIALS & SUPPLIES	MS	37,203,711		37,203,711
PREPAID TAXES & INSURANCE	PPT	4,837,231		4,837,231
PRODUCTION RATE BASE	PRB	713,725,649		1,603,096,694
DEMAND REL PRODUCTION O&M	POMD	32,534,954	94,483,676	127,018,630
FORECASTED INCR IN CPI-URBAN	CPIU	1.036		1.036
ANNUALIZED CAP EQUAL PAYMENTS	CAPEQ	(19,895,700)	(32,370,372)	(52,266,072)
ANNUALIZED ACC'T 555 (OTHER)	FPUR	4,721,544		4,721,544
CUSTOMER ACCOUNTING EXP	CA	19,579,941		19,579,941
A&G EXPENSE	AG	93,509,607		93,509,607
ANN. PROD DEPR EXP (EX DECOMM)	PDX	30,807,579	35,609,476	66,417,055
COAL MINING EQ DEPR EXPENSE	CMEDX	1,359,289		1,359,289
ANNUALIZED GEN PLT DEPR EXP	GDX	2,263,244		2,263,244
ANNUALIZED INT PLT AMORT EXP	INDX	3,915,045		3,915,045
OTHER TAX RATE	OTR	1.11%		1.11%
PRODUCTION RELATED EXPENSES	PXP	94,305,483		260,182,999
INCOME TAX COMPONENT	INCTAX	4,500,911		4,500,911
TOTAL PRODUCTION REVENUE REQUIREMENTS		185,377,888		464,668,410
NET COMPANY CAPABILITY	NSPKW	4,416,000	628,000	5,044,000
MONTHLY PRODUCTION DEMAND RATE	MPDR	$3.50		$7.68

Exhibit B.5-248

LIQUID/GAS FUEL COMBINED CYCLE - CONVENTIONAL

Region: East/West Central

	DISTILLATE	RESIDUAL
Technology Number (a)	44.1	44.2
Unit Size, MW	220	220
Available for Commercial Orders, Year	1985	1985
First Commercial Service, Year	1985	1985
Plant Capital Cost (b), $/kW based on		
Plant Size of (no. of units x unit size)	1 x 220	1 x 220
Total Plant Cost, Dec 1984 $ (a)	447	527
Total Cash Expended (mixed year $)	435	513
AFDC (interest during construction)	26	31
Total Plant Investment (includes AFDC)	461	544
Startup, Inventory, Land	53	48
Total Capital Requirement, Hypothetical Jan 1985 In-Service (includes AFDC)	514	592
Operation and Maintenance Costs (b), 1985 Costs in Dec 1984 $		
Fixed, $/kW-yr	6.6	8.2
Incremental, mills/kWh:		
Variable	1.5	1.9
Consumables	0.2	0.2
Net Heat Rate, Btu/kWh		
Full Load	8150	8230
75% Load	8750	8850
50% Load	9950	10050
25% Load	-	-
Average Annual	8394	8480
Unit Availability (b)		
Planned Outage Rate, %	5.0	5.0
Unplanned Outage Rate, %	0.0	0.0
Equivalent Unplanned Outage Rate, %	4.9	4.9
Operating Availability, %	95.0	95.0
Equivalent Availability, %	90.3	90.3
Average Daily Unavailability, ADU, %	4.9	4.9
Capability Ratio	1.05	1.05
Duty Cycle	INTER	INTER
Minimum Load, %	1	1
Preconst, License, & Design Time, Years	2	2
Idealized Plant Construction Time, Years	2	2
Unit Life, Years	30	30
Technology Development Rating	Mature	Demo
Design & Cost Estimate Rating	Prelim	Prelim

(a) See Section B.5.8 for definition of terms.
(b) For mature plant. Estimated cost ranges in Table C-2, Appendix C.
Reference: In-house estimates.

Exhibit B.5-35B

WOOD FIRED POWER PLANT

Region: West

Technology Number (a)	58.1	58.2
Unit Size, MW	24	12
Available for Commercial Orders, Year	1985	1985
First Commercial Service, Year	1985	1985
Plant Capital Cost (b), $/kW based on		
Plant Size of (no. of units x unit size)	1 x 24	1 x 12
Total Plant Cost, Dec 1984 $ (a)	1693	2227
Total Cash Expended (mixed year $)	1618	2127
AFDC (interest during construction)	159	210
Total Plant Investment (includes AFDC)	1777	2337
Startup, Inventory, Land	127	154
Total Capital Requirement, Hypothetical Jan 1985 In-Service (includes AFDC)	1904	2491
Operation and Maintenance Costs (b), 1985 Costs in Dec 1984 $		
Fixed, $/kW-yr	52.4	80.5
Incremental, mills/kWh:		
Variable	5.0	7.6
Consumables (Steam Byproduct Credit)	-7.7	-15.8
Net Heat Rate, Btu/kWh		
Full Load	16250	19080
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	16740	19650
Unit Availability (b)		
Planned Outage Rate, %	6.7	6.7
Unplanned Outage Rate, %	6.1	6.1
Equivalent Unplanned Outage Rate, %	8.0	8.0
Operating Availability, %	87.6	87.6
Equivalent Availability, %	85.9	85.9
Average Daily Unavailability, ADU, %	2.0	2.0
Capability Ratio	1.08	1.08
Duty Cycle	BASE	BASE
Minimum Load, %	-	-
Preconst, License, & Design Time, Years	2	2
Idealized Plant Construction Time, Years	3	3
Unit Life, Years	30	30
Technology Development Rating	Mature	Mature
Design & Cost Estimate Rating	Prelim	Prelim

(a) See Section B.5.8 for definition of terms.
(b) For mature plant. Estimated cost ranges in Table C-2, Appendix C.
Reference Report: EPRI AP-1403 (see Section B.8).

ARKANSAS POWER & LIGHT COMPANY
DEVELOPMENT OF STANDBY RATE

Summary Of Proposed Rates Under Service Options

PRODUCTION AND TRANSMISSION DEMAND RATES

Monthly Production Demand Rate	7.68
Monthly Transmission Demand Rate	1.13
Production And Transmission Coincidence Rate	10.00%

DISTRIBUTION DEMAND RATES (cumulative for specified voltage level)

Monthly Distribution Demand Rate At Transformation	0.48
Monthly Distribution Demand Rate At Primary	1.24
Monthly Distribution Demand Rate At Secondary	1.70

METERING VOLTAGE LEVEL LOSS FACTORS

Transmission Loss Factor	1.0286
Substation Loss Factor	1.0357
Primary Distribution Loss Factor	1.0481
Secondary Distribution Loss Factor	1.0886

DEMAND RATES FOR SERVICE OPTIONS

A	Transmission, metered at transmission	0.906197
B	Transmission, metered at substation	0.912451
C	Distribution, metered at transformation	1.409587
D	Distribution, metered at primary	2.223020
E	Distribution, metered at secondary	2.809676