BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS ELECTRIC CO-OPERATIVE CORPORATION FOR APPROVAL OF CHANGES IN ITS WHOLESALE POWER RATES TO ITS MEMBERS	)	Docket 04-141-U

PREPARED TESTIMONY OF WILLIAM B. MARCUS

on behalf of

THE ATTORNEY GENERAL

March 8, 2005

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ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET 04-141-U

PREPARED TESTIMONY OF WILLIAM B. MARCUS
ON BEHALF OF THE ATTORNEY GENERAL

I. Introduction

Q Please state your name, business affiliation and address.

A I am William B. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q Please provide your qualifications.

A My qualifications are attached as Exhibit WBM-1. I have over 25 years experience with energy utility issues. I have previously testified or made formal comments before about forty federal, state, provincial, and local utility and environmental regulatory bodies in the U.S. and Canada on issues including utility restructuring and performance-based ratemaking, revenue requirements, resource planning, and cost-of-service and rate design.

I have filed testimony at this Commission on a number of occasions, including the recent general rate cases for Arkla (01-243-U), Arkansas Western Gas Company (02-227-U), and Arkansas Oklahoma Gas Company (02-024-U), Entergy cases involving transition costs (01-041-U) and recovery of extraordinary storm damage costs (01-184-U), both the September, 2000 and September, 2001 phases of the Commission's restructuring investigation (00-190-U), the last Southwestern Electric Power Company [SWEPCO] rate case (98-339-U), and about 20 unbundling cases for distribution co-ops and investor-owned utilities, most of which were settled.

Q On whose behalf are you appearing?

A I am appearing on behalf of the Arkansas Attorney General. I was retained to review a number of aspects of the general rate application filed by Arkansas Electric Co-operative Corporation (AECC or "the Co-op").

I conclude that the company has overstated its case for a rate increase by at least $4.8 million.

However, my rate design recommendation in this case is at least as important as my proposals on revenue requirement. I propose to change the rate design for AECC's demand charges to be based on the average of the four highest month's load in the current and previous 11 months. While this sounds like a highly technical recommendation, it could have significant impacts on reducing the uneconomic and unsustainable promotion of electric heat by AECC and its members, and assure that rate design is based on reasonable cost-based principles.

Q Will you summarize your recommendations?

A I make four specific recommendations regarding the revenue requirement:

1. including a $2.612 million revenue offset for higher generation demand revenues received by AECC in 2004 to match the $12.2 million in out-of-test-period 2004 purchased power capacity costs. The new capacity is being purchased to meet higher loads in 2004, but none of the revenue from those higher loads is included in the rate filing.

2. reducing the revenue requirement by an additional $1.00 million to reflect the expiration of a lease for coal mining equipment identified in the response to NUCOR DR 106;

3. increasing revenue by $0.47 million to normalize widely varying revenues from sales of emissions allowances through use of a five-year average rather than a single test-year figure;

4. removing $0.78 million of costs of promotion of electric heat from advertising and marketing expenses, because promoting electric heat is not in the interests of the co-op and its members, and is "promotional advertising" that may not be recovered from customers.

I note that the Staff will be conducting a more detailed review of revenue requirement issues and is likely to identify additional areas where the revenue requirement is overstated.

Regarding cost of service and rate design, I have the following recommendations:

1. Reclassify approximately $20 million in AECC's generation costs from demand to energy in seven areas. Offsetting this recommendation, remove the $12.1 million "judgmental" shift from demand to energy included in AECC's proposed rate design (left over from a previous stipulation between AECC and Staff), for a net shift of about $8 million from demand to energy.

2. Redesign AECC Rate 1 to collect demand costs based on the average coincident peak demands in the four highest months of the current and previous 11 months. This rate design ensures that price signals are provided to the distribution co-ops that high winter loads are costly. Adopt a three-year phase-in mechanism to reduce the impacts on the few co-ops who could see relatively large rate impacts.

II. Revenue Requirements Issues

A. Revenue Adjustment to Match New Capacity Contract

Q Will you discuss the matching of additional out-of-test period capacity costs with out-of-test period loads?

A AECC has requested inclusion in rates of $12.2 million of capacity costs that begin in 2004, while providing billing determinants and load data for a 2003 test year without adjustment. Those out-of-period capacity costs are required to serve load growth after the end of the test year. Otherwise, AECC would have purchased the capacity earlier, and its costs would have been included in the test year. Therefore, it is fundamentally unfair to include a cost only necessary to serve future loads without including the revenue created by the future loads.

Q What do you recommend?

A I recommend including an additional $2,612,285 in generation demand revenue (for Rate 1 and Rates IC-1 and 2) in the test year to match the cost of the contract with the loads that caused the need for it. This is the incremental generation demand revenue (net of interruptible credits) that AECC received on these rate schedules in 2004 relative to 2003. I computed this revenue by subtracting the 2003 figures shown in Schedule G-10-A-1 from the 2004 revenues shown in the response to AG DR 3-1. I have included this revenue as an offset so that it will not be necessary to change the 2003 billing determinants used by all parties to design rates in this case.

Q Why didn't you include energy costs and revenues and transmission demand revenues and billing determinants for 2004?

A AECC's fuel costs will increase as its energy demand increases. Similarly, its transmission contracts, which constitute a large portion of its transmission costs, are load-sensitive. Their costs will also increase above test year levels as load increases. I therefore believe that including the generation demand revenues provides a reasonable balance against the out-of-test period generation capacity contract cost without including the other revenues.

B. <u>Expiration of Coal Mining Lease</u>

Q Will you discuss the leasing of coal mining equipment at the Antelope Mine?

A AECC shows coal mine lease expenses of $1,151,180 in its response to AG DR 1-16. A large portion of these expenses relates to a lease that expires at the end of 2004 when AECC exercised its right to repurchase the equipment for $1. Remaining recurring costs are $150,166. Because $1,001,014 of the costs incurred in the test year will not recur in the future, the test year is not representative of future years and only the non-recurring amount should be allowed in rates. A downward adjustment of $1,001,014 is therefore recommended.

C. Normalize Revenues from Sale of Emissions Allowances

Q How has AECC treated revenues from the sales of emissions allowances?

A AECC has included test year 2003 revenues of $252,860 as an offset to its demand costs.

Q Have those revenues fluctuated in recent years?

A Yes. The table below, taken from the response to AG DR 1-14 and its supplement shows that revenues have ranged from zero to $3.15 million over the last five years.

Table 1: Emissions Allowances Sales Revenues

2000	$	99,500
2001	$	142,252
2002	$	0
2003	$	252,860
2004	$	3,140,194
5-year average	$	726,961

The response to AUD-019 indicated that there are two types of emissions sales, voluntary and involuntary. The bulk of the 2004 sales ($2,940,815) were voluntary sales of surplus allowances by the Company.

Q Will you evaluate this information?

A The Attorney General contends that proceeds of all emissions allowance sales, whether voluntary or involuntary, should be reflected in rates, because those sales arise only because the utility was granted a certain number of valuable emissions allowances from its ownership of powerplants funded by ratepayers. If AECC were in the opposite position and needed to purchase allowances, those purchases would certainly be included in the cost of service.

At the same time, voluntary emissions sales are likely to be infrequent events. Therefore, we recommend averaging these voluntary revenues over a relatively long period of time. In fairness to AECC, even involuntary sales revenues tend to

fluctuate. A five-year average of involuntary revenues is $138,798. In sum, and in light of the fluctuations in this account, I recommend using a five year average for both involuntary sales revenues and voluntary sales revenues. The average over the five year period is $726,961, which is $474,101 greater than AECC's figure for TY 2003. I recommend that this amount be used as the estimate of emissions allowance revenues because of the large fluctuations in the account. While the high level of sales in 2004 is non-recurring, additional voluntary sales could still occur at a later time. The five year average that I recommend is therefore a reasonable way of passing these revenues back to ratepayers while reflecting the existence of significant fluctuations.

D. <u>Electric Heat Promotion</u>

Q Do you have any concerns regarding AECC's advertising and other expenditures to promote electric heat?

A Yes. As discussed in detail below, the promotion of electric space and water heating is highly inadvisable. We do not believe that either the rate design or the advertising money spent by AECC should promote electric heat.

Q How much money is AECC spending on electric heat promotion?

A It is spending money in Account 913 (which it calls "energy efficiency spending") to advertise electric space and water heating. (See response to AG DR 5-1). The amount spent is $773,200 in Account 913, plus $5,050 in Account 912 for the Arkansas Heat Pump Association.

Q Will you explain why AECC believes that such spending is a legitimate responsibility of ratepayers?

A AECC references Arkansas statute 23-4-207. This statute explicitly disallows recovery for "promotional advertising," but contains an exception to allow recovery of spending on activities that promote the efficient use of energy or increase load factors.

Q Do you believe that electric heat promotion at present meets the criteria of this statute?

A No. Even though AECC calls such spending "energy efficiency," it is not. I demonstrate below that the combination of electric space and water heating uses more energy than the direct combustion of gas, even with a heat pump. I also demonstrate that the promotion of electric heat has turned AECC into a dual peaking system and has made a number of the individual distribution coops winter peaking. Therefore any benefits from increasing the system load factor from electric space heating have reached their limit. I therefore believe that this spending is not justified either as a matter of public policy or under the statutory criteria and should no longer be allowed.

Q Have costs related to the promotion of electric heat been removed in other cases?

A Yes. I am specifically familiar with the last SWEPCO case (Docket 98-339-U), where Staff witness Richmond proposed to remove a fairly large block of costs related to promotion of heat pumps. While that case was settled and therefore is not precedential, SWEPCO agreed in that settlement to the removal of those costs.

Q What is your recommendation?

A I recommend that the Commission remove $778,250 from Accounts 912 and 913 to remove advertising and memberships related to electric heat promotion.

III. Cost Allocation and Electric Heat Policy

Q Will you describe AECC's cost allocation and rate design?

A AECC's rates are (like many wholesale rates) divided into demand and energy charges. The energy charges are based generally on fuel and variable costs, plus hydro generation costs, plus approximately $6/MWh. The demand costs contain the remaining costs. Demand costs are billed on Rate 1 to distribution co-ops based on the lower of the average of four summer months' coincident demands or

90% of the co-op's coincident demand in the peak summer months. Interruptible customers' demands in the IC-1 and IC-2 rate classes are based on the average non-coincident demand in the current month and the previous 11 months.

Q What is AECC's view of this rate design?

A Its policy views are expressed in the response to AUD-15, which I have attached as Exhibit WBM-2. It asserts that the current rate design based on summer coincident peaks encourages increases in load factor by distribution co-ops and encourages load management. AECC also states its belief that a fixed-variable rate design is cost-based.

> By traditionally placing fixed costs in AECC's demand charge and variable costs in its energy charge, AECC has sent a proper, cost based, wholesale price signal. The fixed cost of generation and transmission are most radically affected when new plant is acquired. New plant investment is often mandated by the on peak demand for electricity. If demand is priced in such a way as to signal the cost of capacity, then there is a direct price signal.
>
> This price signal has led to extensive peak shaving efforts on the part of AECC's distribution cooperatives and in the successful offering of AECC's IC (interruptible credit) rates. These efforts have forestalled the building of peaking capacity.
>
> AECC's energy charge is primarily driven by costs that vary with kWh production. If AECC is not in an on peak period, it is reasonable for members to be charged the variable cost of production associated with their kWh consumption. This variable kWh charge encourages off peak load building, load factor improvement, and a lower average cost per kWh consumed.

Q What incentives does this rate design give to the distribution co-ops when they purchase power under Rate 1?

A Essentially, the rate design of AECC gives distribution co-ops the price signal that anything that raises the load during the peak hours of the summer months is extremely valuable, but they can buy energy during the eight non-summer months for about 2.2 cents/kWh with no demand cost responsibility (because the demand charges that they pay during the winter are based on loads experienced in the

previous summer). I calculate that AECC's proposed rates, backcast to 2004, give co-ops a price signal that power is worth approximately 7.5 cents/kWh for the four summer months (more in the summer peak hours) and 2.2 cents/kWh in other months.

As a result, distribution coops receive extremely strong incentives for off-peak load building, as noted by AECC. They can and do pass through the lower energy costs to their customers through declining block rates and promote the installation of electric space and water heating in competition with natural gas.

Q Do the distribution co-ops offer declining block rates in the winter months?

A Yes. Every single distribution co-op served by AECC has a declining block rate in the winter months, with a tailblocks ranging from 0.5 cents/kWh less than the first block to as much as 3.5 cents, as shown below.

- Arkansas Valley 99-255-U 1.85 cents/kWh
- Ashley-Chicot 99-252-U 1.87 cents/kWh[1]
- C&L 99-257-U 1.00 cents/kWh
- Carroll 99-256-U 0.86 cents/kWh
- Clay County 99-265-U 0.5 cents/kWh
- Craighead 99-253-U 0.9 cents/kWh
- First 99-258-U 1.41 cents/kWh
- Mississippi County 99-259-U 3.5 cents/kWh
- North Arkansas 99-260-U 1.8 cents/kWh
- Ouachita 99-238-U 0.47 cents/kWh
- Ozarks 99-250-U 1.00 cents/kWh
- Petit Jean 99-261-U 1.3 cents/kWh
- Rich Mountain 99-262-U 1.80 cents/kWh
- South Central Arkansas 99-248-U 0.6 cents/kWh
- Southwest Arkansas 99-263-U 2.30 cents/kWh
- Woodruff 99-264-U 3.8 cents/kWh

[1] This is the difference from the second to the third block. The first block of 100 kWh is functionally part of the customer charge as very few customers use less than 100 kWh.

Q Do the distribution co-ops take other steps to promote electric heat?

A Yes. Some co-ops (such as Woodruff) are touting the inexpensive nature of heat pumps based on all-in winter rates (including distribution co-op costs) of 4 cents/kWh. A number of co-ops offer relatively low interest loan programs to encourage their customers to switch from gas. I am attaching the relevant portion of several distribution co-op web pages that promote heat pumps as Exhibit WBM-5.

Q Are these incentives reasonable?

A No. The strong incentives to support winter load building have outlived their usefulness in several ways. I will identify four different reasons briefly here and then return to discuss each in more detail.

1. AECC is no longer a uniform summer peaking utility. AECC has successfully promoted so much winter load growth that it is better characterized as dual peaking. Its highest two peak months are in July and August, but the December-February period has recently produced at least one, if not two, monthly peaks that exceed the peaks in both September and June. This is a relatively new phenomenon that has begun to occur in the last several years.

2. The deregulated wholesale energy market coupled with dramatic increases in the cost of natural gas (used to fuel electric powerplants) means that the promotional rate bears no relation to the real world. AECC loses money when it sells kilowatt-hours for an energy cost of $22 per MWh with no demand contribution. It recovers those losses by having a higher fuel adjustment charge.

3. Third, AECC is acting in a vacuum and ignoring the potential for adverse impact of electric heat promotion on Arkansas' gas utilities, which appear to be losing customers, and their remaining customers.

4. Electric heat is inefficient from the point of view of total energy use and environmental emissions when compared to natural gas.

Q Will you support your first claim that AECC is no longer a summer peaking utility?

A Figures 1-3 summarize information from AG 3-7, Schedule G-10-A, and AG 3-1. They compare the monthly coincident peak loads of AECC's Rate 1 (non-interruptible) customers in 1998 test year 2003, and pro forma year 2004 grouped by seasons as a percentage of the summer peak load. Further graphs showing the coincident peak loads in each month as a percentage of the summer peak load in 1999-2003 and underlying data are provided in Exhibit WBM-3.

Figure 1: 1998 Rate 1 AECC Monthly Peak Loads

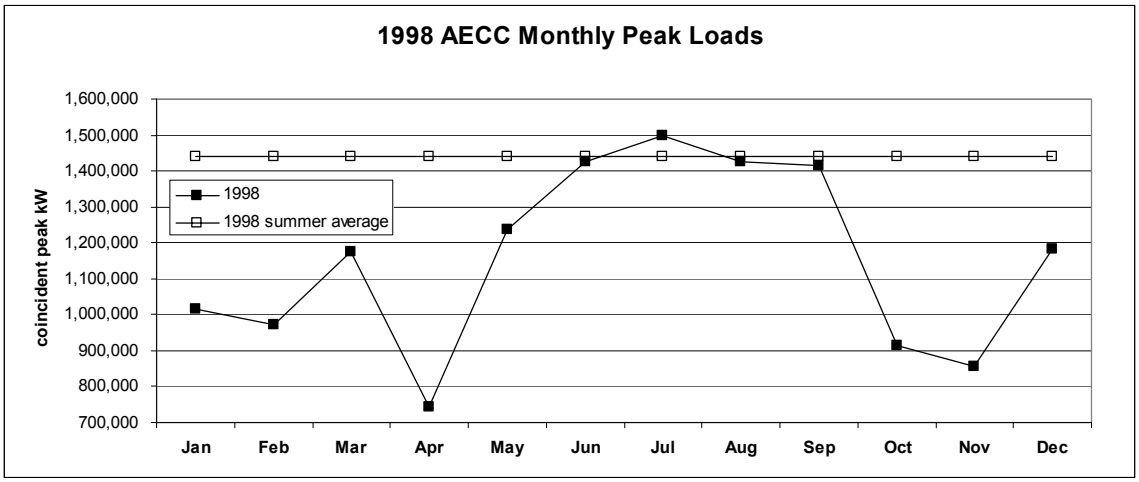


Figure 2: 2003 Rate 1 AECC Monthly Peak Loads

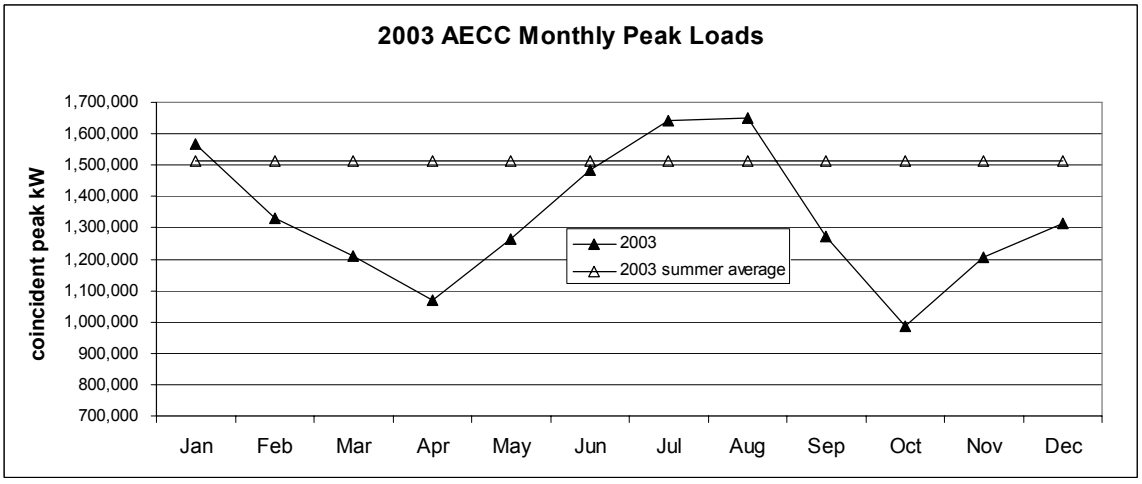
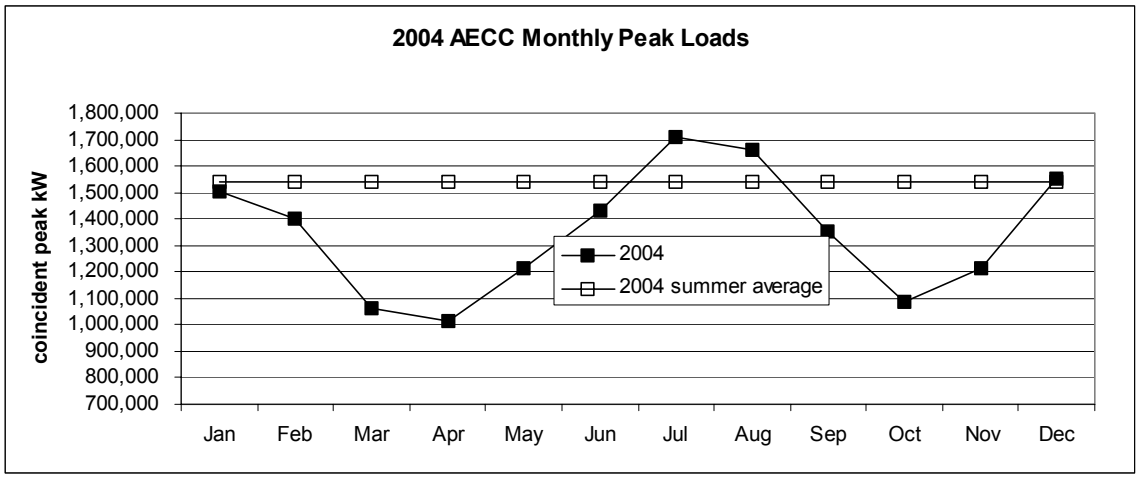


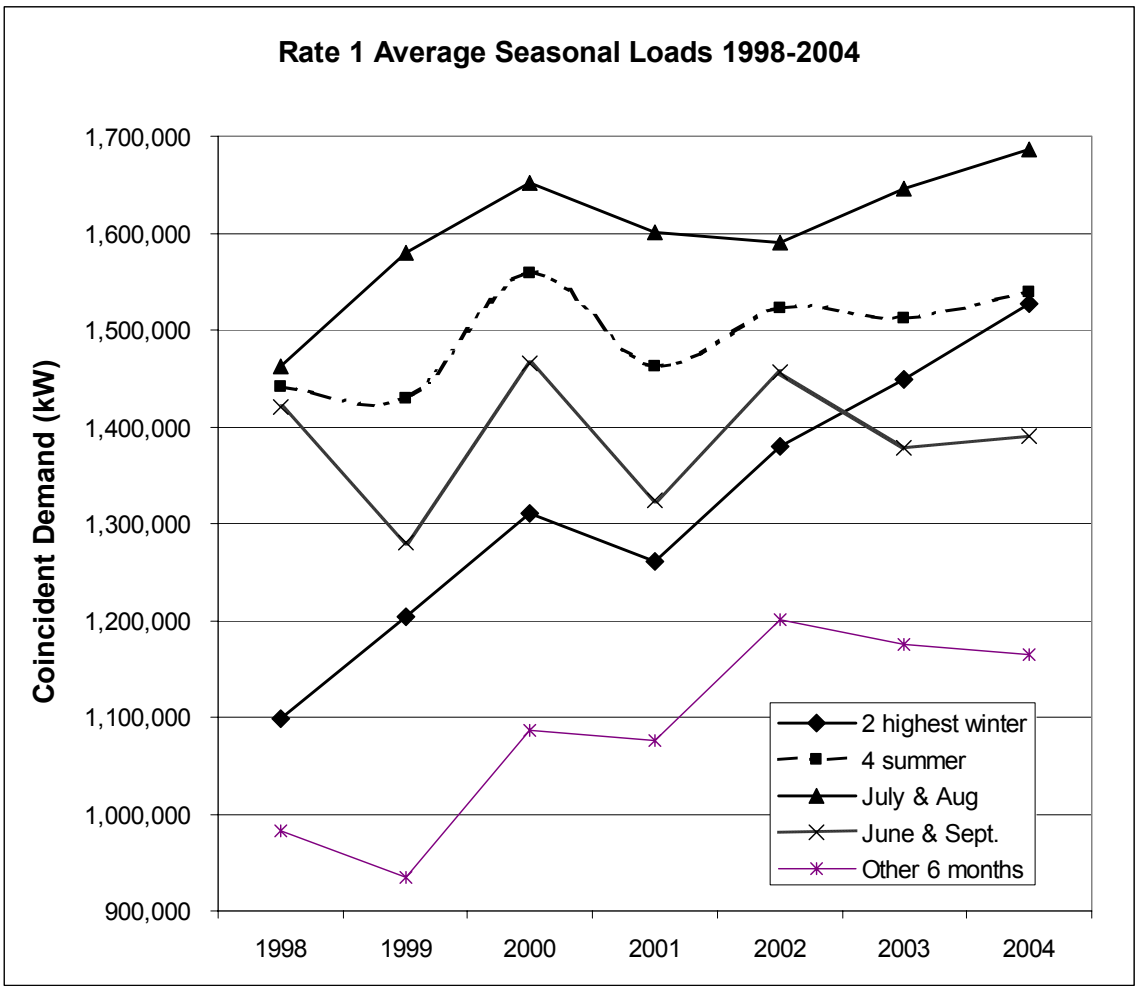
Figure 3: 2004 AECC Rate 1 Monthly Peak Loads



The graphs and their underlying data demonstrate a dramatic increase in winter peak loads. In the late 1990s, winter loads were well below the summer loads, but this relationship has changed dramatically. By 2000, winter peak (December) loads exceeded one of the four summer months for the first time, as shown in Exhibit WBM-3. In 2003, three winter peak months (December, January, and February) exceeded September loads. And loads in two winter months of 2004 (December and January) exceeded the loads in two summer months (June and September), while February loads exceeded the September loads. The highest winter peak loads have exceeded 90% of the summer peak load in both 2003 and 2004 and reached as much as 95% of the maximum summer load.

Figure 4 shows the kilowatt growth by seasons.

Figure 4: Rate 1 Average Seasonal Loads 1998-2004



These results reflect major changes in growth patterns over time, shown in Table 2 below. Winter peak and energy loads have increased an average of 5.8% per year from 1998-2004 with winter energy rising by 5.5%. Shoulder loads have increased by 2.1% for peak and 2.9% for energy, while summer loads have increased much more slowly (1.1% peak and 0.6% energy).[2]

[2] While the figures are different, the pattern of higher winter growth rates is evident through shorter periods than 1998-2004.

Table 2: Rate 1 Compound Peak and Energy Growth by Month, 1998-2004

	Peak Growth	Energy Growth
Jan	6.7%	5.3%
Feb	6.3%	6.7%
Mar	-1.6%	1.2%
Apr	5.2%	3.7%
May	-0.3%	2.3%
Jun	0.1%	0.2%
Jul	2.2%	0.1%
Aug	2.6%	1.0%
Sep	-0.8%	1.2%
Oct	2.9%	3.8%
Nov	6.0%	4.1%
Dec	4.6%	4.8%
Total	2.6%	2.6%
4 summer	1.1%	0.6%
3 winter	5.8%	5.5%
5 shoulder	2.1%	2.9%

As a result of these differential growth patterns, energy delivered in December, January, and February has increased from 23% to 27% of Rate 1 annual energy from 1998-2004. Summer energy (June-September) decreased from 42% to 37%, while shoulder energy has remained in the 35% range. In essence, because of its success at promoting electric heat, its old rate structure is no longer justified because AECC is no longer strongly summer peaking.

Q Are any of the distribution co-ops actually winter peaking?

A Yes. Data on coincident loads from Schedule G-10-1-A for 2003 and AG DR 3-1 for 2004 (included on the first two tables of my Exhibit WBM-4) show that a number of co-ops have a winter peak. In 2003, six of the 16 distribution co-ops' Rate 1 loads hit their own highest monthly coincident peak in January (First, Mississippi County, North Arkansas, Petit Jean, South Central, and Woodruff). Two co-ops were winter peaking in 2004 (Mississippi County and Petit Jean), and a third (Southwest Arkansas) had a January peak higher than the system coincident peak in July though 0.2% lower than its August peak.

Q Does any other information suggest that winter peak loads should be considered in the cost allocation and planning process?

A Yes. There are two reasons associated with generation and transmission planning.

First, AECC is running out of room to schedule generation maintenance in winter periods, so that its reserve margins after scheduled maintenance are lower in some winter months than in peak summer months. It scheduled the maintenance of a 280 MW coal-fired generating station from February 7 to March 27 2004. (AG DR 3-4) After factoring in this level of maintenance (which was coincident with the 1400 MW monthly peak load experienced on February 8 according to AG DR 6-1), AECC's reserve margin after scheduled maintenance was actually lower in February than in August or any other month except July (which had a lower margin by only about 20 MW). This result occurred even though February is not one of the four highest peak months of the year.

Second, the fact that some of the co-ops' firm loads are becoming winter peaking could have the effect of moving the **transmission** system peak into the winter months, particularly on the Entergy and SPA systems. Transmission wheeling rates are ratcheted on the highest demand in the previous 12 months. (AG DR 6-2) We cannot make a definitive statement, as we are not certain how the loads are split between Entergy and other utilities for co-ops taking transmission delivery from both Entergy and Swepco or SPA. However, the one co-op connected to the SPA system (North Arkansas) peaked in the winter in 2003 as did six co-ops connected to Entergy. Table 3 shows the underlying data for the Entergy system.[3]

[3] The Rate 1 load data are the total loads taken from Exhibit WBM-4 for the co-ops listed as interconnected with Entergy in the response to AG DR 7-2.All IC-1 and 2 customers are served through co-ops interconnected with Entergy.

Table 3: Monthly Coincident Peak Loads of Co-ops Interconnected with Entergy

	Entergy coops Total Rate 1	IC-1 and 2 Entergy coops	Nucor Load	Total Entergy Load
Jan-03	1,337,296	65,512	255,963	1,658,771
Feb-03	1,126,660	59,310	277,547	1,463,517
Mar-03	1,020,758	67,346	316,497	1,404,601
Apr-03	901,588	62,160	384,588	1,348,336
May-03	1,047,714	64,897	377,253	1,489,864
Jun-03	1,232,183	73,775	288,067	1,594,025
Jul-03	1,362,761	74,745	245,744	1,683,250
Aug-03	1,360,138	73,246	348,533	1,781,917
Sep-03	1,056,246	79,476	276,657	1,412,379
Oct-03	819,180	63,647	303,647	1,186,474
Nov-03	1,024,713	44,059	365,507	1,434,279
Dec-03	1,105,387	67,549	334,133	1,507,069
Jan-04	1,309,610	68,774	403,049	1,781,433
Feb-04	1,224,051	65,980	209,318	1,499,349
Mar-04	922,616	65,283	404,020	1,391,919
Apr-04	889,921	66,823	366,353	1,323,097
May-04	1,044,990	69,539	297,988	1,412,517
Jun-04	1,211,054	57,286	245,830	1,514,170
Jul-04	1,451,112	74,552	267,948	1,793,612
Aug-04	1,407,963	69,894	312,325	1,790,182
Sep-04	1,169,643	75,108	221,970	1,466,721
Oct-04	938,304	73,066	415,121	1,426,491
Nov-04	1,036,826	64,221	306,613	1,407,660
Dec-04	1,334,793	59,015	296,458	1,690,266

The total firm loads of all co-ops connected to the Entergy system were only 25 MW less in January than at the summer peak in 2003. This means that the Entergy transmission system cannot be definitively defined as summer peaking. Whether the Entergy transmission system peaks in the summer or winter will end up being dependent on random fluctuations in the Nucor loads (which can vary by as much as 150-200 MW at the time of the monthly system coincident peak).

Even more telling, the January 2004 coincident peak load (firm plus IC-1 and 2 for co-ops interconnected with Entergy, plus Nucor) was only 484 kW (0.03%) less than the load in August 2003. **It was a completely random event that a winter transmission peak did not occur.** In 2004, there were three months (including January) with a coincident peak within 2% of the system peak (only 12 MW difference between the third-highest month and the peak month). Given that three months are within 2% of each other, it is unreasonable to set costs as if the Entergy transmission peak will always occur in the summer. It can reasonably be concluded that the Entergy transmission system demand could potentially peak in the winter now. And it stands to reason that a transmission peak in the winter will become even more likely in future years if electric heat continues to be promoted.

Q Will you provide detail on your second claim that energy sold to distribution co-ops for electric heat is sold at less than the market price of energy, causing AECC's rates to rise?

A The responses to AG DRs 4-1, 4-2, 4-3 and 4-4 provide information on AECC's generation, economy energy purchases and sales in each month. Because of its generation configuration, AECC is often either a purchaser or seller of energy – selling surplus coal-fired energy into the market and purchasing energy from other utilities to avoid the use of expensive gas-fired energy. In addition, during hours when market prices are high AECC generates some energy with its own gas-fired resources or using its natural-gas-fired contract capacity from Entergy. Table 4 shows AECC's market-based economy purchases and sales and gas-fired generation in 2003-2004 during the eight non-summer months when energy is being sold to Rate 1 customers at approximately $22/MWh with no demand cost.[4]

[4] Purchases and sales are added in Table 4 rather than subtracted because they generally occur in different hours; AECC purchases power at some times and sells power at other times. Both purchases and sales reflect the market price of energy when they occur. Expensive gas-fired generation is the last resort and is used when purchased power is either more expensive than gas or unavailable.

Table 4: Market Prices for AECC Energy During Non-Summer Months 2003-2004

	non-summer 2003			non-summer 2004		
	MWh	cost	$/MWh	MWh	cost	$/MWh
economy purchases	1,613,141	54,383,599	33.7	1,029,768	39,071,768	37.9
economy sales	500,265	18,297,851	36.6	300,506	10,466,506	34.8
gas generation (including Harrison County)	183,071	8,567,628	46.8	172,377	9,604,871	55.7
TOTAL market transactions and gas generation	2,296,477	81,249,077	35.4	1,502,651	59,143,145	39.4
Total Energy Deliveries	6,796,699			7,135,229		
Rate 1 Energy Deliveries	4,686,385			4,814,814		
market transactions and gas generation as % of total energy	33.8%			21.1%		
market transactions and gas generation as % of Rate 1 energy	49.0%			31.2%		
	3 peak winter months 2003			3 peak winter months 2004		
economy purchases	591,029	20,919,477	35.4	299,329	10,811,409	36.1
economy sales	102,118	3,694,994	36.2	123,388	4,201,855	34.1
gas generation (including Harrison County)	94,571	4,833,169	51.1	67,060	3,840,281	57.3
TOTAL market transactions and gas generation	787,718	29,447,640	37.4	489,777	18,853,545	38.5
Total Energy Deliveries	2,821,162			2,960,315		
Rate 1 Energy Deliveries	2,034,179			2,095,688		
market transactions and gas generation as % of total energy	27.9%			16.5%		
market transactions and gas generation as % of Rate 1 energy	38.7%			23.4%		

Thus, during many hours, the incremental energy cost (market plus gas) in 2004 ranges between $35 and $55 per MWh, with an average cost around $40. As a result, when the G&T co-op sells energy at $22 but must buy it (or forego a profitable economy sale) at $35-$55, all the rates to the distribution co-ops must rise (through an increase in the fuel adjustment charge). So the big push to build winter electric space heating load is costing every distribution co-op and every distribution co-op member money.

Q Do you have any other data that generally confirms that market energy costs exceed the co-op's rates during the winter months?

A Yes. Data from the Intercontinental Exchange (ICE – www.theice.com) for the Entergy market hub show peak prices (16 hours per day, five weekdays per week) that averaged $45/MWh during the eight non-winter months and $44/MWh during the three winter peak months of 2004.[5] These peak prices were very stable with only three days below $30 and five days below $35 in the 8-month non-summer period.

Q What do you conclude from this information?

A When off-peak coal-fired energy was worth $15 or less in the open market and both the co-op and the region had huge capacity surpluses (conditions in place in the mid 1980s when AECC had its last full-fledged rate case), selling the energy to distribution co-ops at $22/MWh may have made sense(at least in the short-term). But the rising gas prices and market electricity prices mean that promoting electric heat is no longer good for remaining customers, but is instead a source of rising electricity rates. In essence, the marginal energy cost (represented by the Arkansas market price) greatly exceeds $22/MWh.

As a result, continued promotion of electric space and water heating at rates below wholesale market prices has the clear effect of raising the wholesale rates that AECC must charge to its member distribution co-ops. In other words, there is no longer a golden egg from indiscriminately increasing the load factor by promoting electric heat. Instead, AECC's rate design does a disservice to its member co-ops by using up the limited supply of cheap power to compete with gas companies to serve electric heat loads rather than using it to support regional economic development or selling it on the open market at higher prices.

It simply violates cost causation and does not provide reasonable rates when AECC sends price signals to distribution co-ops that electricity is worth only $22/MWh when it must turn around and purchase incremental electricity at higher prices to serve the load at $22/MWh (or forego higher revenues from sales),

[5] Prices averaged only $47 during the four summer months.

particularly when it is also at risk of incurring ratcheted transmission demand charges set during a winter month.

Q Will you turn to your third issue regarding the impact of electric heat promotion on gas utility loads and costs?

A Arkla and to a lesser extent Arkansas Oklahoma Gas have reported actual customer losses. Arkla claims the loss of 23,000 customers from January 2001 through June 2004, with customer losses concentrated in relatively rural areas.[6] Arkansas Oklahoma Gas also reports fewer customers at the end of 2003 than at the end of 2000.[7]

To the extent that this is true (and if the local distribution company has not lost customers as a result of imprudent actions or choices), a declining gas utility customer base may cause utility transmission and distribution expenses to be spread over fewer customers and may raise rates for those who remain.

Fair competition is one thing, but selling electricity well below the incremental cost of producing it to stoke new electric heat loads at the expense of the co-ops' existing customers makes no sense, particularly when there is a feedback loop that could raise rates for remaining gas customers throughout the state. The G&T co-op's encouragement of electric heat through its rate design thus not only raises rates of all its existing members but potentially may raise rates of gas customers all over Arkansas.

Even though the G&T co-op's responsibility is to its members, the Commission has a broader responsibility to take these public interest considerations into account when setting a rate design policy for AECC.

[6] Workpapers to Schedule E-12 in Docket 04-121-U and testimony of Alan Henry, Schedules ADH-7 and ADH-8.. The Attorney General's Office and the Commission's General Staff are at this writing reviewing the numbers reported by Arkla. These numbers are therefore not confirmed, and may be adjusted

[7] Arkla response to AUD-237 in Docket 04-121-U. This is Arkla's reporting what AOG has reported. As with Arkla in Docket 04-121-U, in Docket 05-006-U, the Attorney General's Office and the Commission's General Staff will be reviewing the numbers reported by AOG, and therefore these numbers may be adjusted.

Q Finally, will you discuss the question of energy efficiency?

A Gas is generally a more efficient choice than electricity because of the efficiency losses in conversion from the fuel to the powerplant, as shown in Table 5. Only a heat pump fueled entirely by a modern gas-fired combined cycle (with a heat rate in the vicinity of 7000 Btu/kWh plus line losses) shows a greater efficiency than electric use. But the heat pump does not stand alone. An all-electric home includes an electric water heater (as well as electric cooking and clothes drying), which are less efficient than gas. Electric resistance heating is also considerably less efficient. Moreover, because of the greater carbon content in coal than in gas, emissions of carbon dioxide are significantly greater with coal-fired electric space heating (even with a heat pump) and water heating than direct gas combustion for the same end uses.

Table 5: Total Energy Efficiency of Natural Gas vs. Electric Service for Residential End Uses

	gas	electric combined cycle	coal steam
gas vs. electric resistance heat			
end-use efficiency	80%	100%	100%
conversion and delivery efficiency *	98%	46%	32%
implicit heat rate Btu/kWh	4,353	7,420	10,600
efficiency	78%	46%	32%
energy required for end-use electricity relative to gas		170%	243%
CO2 per MMBtu of heat input (pounds)	119	119	210
CO2 for same useful output as 1 MMBtu of gas heat input	119	203	511
additional CO2 for electric option		70%	330%
gas vs.air-source heat pump (Heating Seasonal Performance Factor = 7.0)			
end-use efficiency	80%	205%	205%
conversion and delivery efficiency	98%	46%	32%
implicit heat rate Btu/kWh	4,353	3,618	5,168
efficiency	78%	94%	66%
energy required for end-use electricity relative to gas		83%	119%
CO2 per MMBtu of heat input (pounds)	119	119	210
CO2 for same useful output as 1 MMBtu of gas heat input	119	99	249
additional CO2 for electric option		-17%	110%
water heater			
end-use efficiency	60%	87%	87%
conversion and delivery efficiency	98%	46%	32%
implicit heat rate Btu/kWh	5,804	8,529	12,184
efficiency	59%	40%	28%
energy required for end-use electricity relative to gas		147%	210%
CO2 per MMBtu of heat input (pounds)	119	119	210
CO2 for same useful output as 1 MMBtu of gas heat input	119	175	441
additional CO2 for electric option		47%	270%
clothes dryer			
end-use efficiency (relative to electricity to dry same amount of clothes)	89%	100%	100%
conversion and delivery efficiency	98%	46%	32%
implicit heat rate Btu/kWh (adjusted for slightly lower gas end-use drying efficiency)	3,926	7,420	10,600
efficiency	87%	46%	32%
energy required for end-use electricity relative to gas		189%	270%
CO2 per MMBtu of heat input (pounds)	119	119	210
CO2 for same useful output as 1 MMBtu of gas heat input	119	225	567
additional CO2 for electric option		89%	376%

* Gas delivery losses between the site of a powerplant and a residence. Electric efficiency based on combined cycle heat rate of 7000 Btu/kWh, coal heat rate of 10000 Btu/kWh, 6% line loss.

Q Will you summarize your conclusions on this issue?

A The AECC cost allocation and rate design is:

(1) promoting electric heat,

(2) turning a former summer peaking utility into a dual-peaking system, so that the generation and transmission cost allocation practices that led to the electric heat promotion are no longer justified;

(3) raising rates to distribution co-ops and their members by selling electricity to fuel new electric heat loads well below market prices, so rates are not reasonably related to costs;

(4) perhaps causing gas utilities to lose load and to possibly raise their rates to all Arkansas consumers; and

(5) increasing both energy use and environmental emissions because of the inefficiency of conversion of heat to electricity.

AECC's fixed-variable cost allocation with demand costs assigned entirely to the summer months thus creates a completely unsustainable lose-lose scenario all the way around. AECC's customers lose through higher fuel adjustment charges and capacity needs in the winter months, while gas company customers may lose through higher rates.

Q How has the Commission previously dealt with issues related to AECC's cost classification and rate design?

A It has generally deferred to the Co-op's Board of Directors. I reviewed Commission orders in Dockets U-3071, 84-084-U, and 93-132-U. These orders have given deference to AECC's board of directors on cost allocation issues. In particular, in Docket 84-084-U, Order #13, the commission upheld AECC's proposed cost allocation, stating:

> In the context of a cooperative we are somewhat reluctant absent a substantial reason to substitute our judgment on cost allocation in contradiction of that of the majority of its duly elected board of directors.… In short we believe that absent a substantial reason to do otherwise there is reason for the Commission to accord some limited

> degree of deference to the decisions of the cooperative's board of directors on cost allocation or rate design questions, that we might not be inclined to accord the decisions of an investor owned utility.

As a result of giving deference to the AECC board, the Commission upheld the four-month summer coincident peak methodology that is currently in use, rejecting the Staff's proposal for an average-and-peak allocation (similar to that adopted for the IOUs) and also rejecting a single coincident peak.

Q Are the factors which the Commission outlined in 1984 applicable today?

A No. While it may be reasonable at the highest level of general principle to give AECC's Board of Directors some deference that would not be given to an investor-owned utility, the Commission cannot abdicate its responsibility to the pursuit of the broader public interest – even in the face of opposition from AECC's board.

In 1984, the Commission found that a four-month summer peak allocation is not "arbitrary, irrational, or unjustly discriminatory." The evidence which we are bringing forward in this case -- 20 years later – after many facts and circumstances have changed, suggests that the Commission should now reach a different conclusion. Even though AECC and its member co-ops seem to be happy with the current system, the promotion of electric heat that has occurred and has even accelerated in recent years as a result of this cost allocation method is not in the public interest. The Commission should not defer to the AECC Board on this issue because it should instead give more weight to the public interest factors described in detail earlier in this testimony.

Q Is there a compelling reason why the Commission needs to act in this case rather than waiting until later?

A Yes. Waiting and doing nothing will just make the problem worse. Mr. Kessenger's testimony at page 11 states: "It is AECC's current plan not to return to the APSC for rate relief for a number of years." As a result, if the Commission does nothing now, there will be a significant period of time when AECC and the

distribution co-ops will continue to promote electric heat with all the adverse impacts on the public interest that I have identified.

As I discuss below, a relatively small change to the way that the demand billing determinants are calculated can shift incentives dramatically without major impacts on the distribution co-ops and their customers, **if the Commission acts now**. Any adjustments to rates to reflect changing costs caused by electric heat would be more painful and difficult to accomplish later – with even more electric heat load on the system and even higher winter peak loads. Failing to act now will make the problem of electric heat promotion that much harder to deal with in five, ten, 15, or even 20 years (whenever AECC decides to come back before the Commission for another general rate case).

IV. Cost Allocation and Rate Design

Q How is your cost allocation and rate design testimony organized?

A I first present information supporting changes in cost classification of certain items from demand to energy. I then provide a rate design recommendation to change the definition of billing demand to remove the incentives to promote electric heat. Lastly, I evaluate the impacts of this proposed change on Rate 1, Rates IC-1 and 2, and the individual distribution co-ops, find that changes are relatively small for most co-ops, and make a proposal to phase in the change in billing demand to mitigate impacts on the few co-ops facing significant increases.

A. Production Cost Classification

Q Turning to cost classification, do you propose to change the classification of any costs in the cost of service study from demand to energy or vice versa?

A Yes. I propose to change the classification of the following items:

1. Rents associated with coal mine equipment
2. Allocation of revenues received from surplus energy sales

3. Amortization of debt expense (classify some to transmission and some generation costs to energy)

4. Generation margin

5. Costs allocated to generation using the rate base allocator

6. Costs allocated to generation using the O&M payroll allocator

7. Costs allocated to generation using the total revenue requirement allocator

Q Will you explain your proposed change for rental expenses associated with coal mine equipment?

A AECC incurs coal mine equipment lease expenses of $1,151,180 in Account 507, which it includes as demand costs (AG DR 1-16). These costs should be treated as energy costs because they are directly related to the extraction of fuel. Moreover, if AECC were buying its coal at arm's length, the costs of similar equipment would be a cost incurred by the fuel supplier that would be recovered by the fuel supplier in fuel costs, becoming part of the energy charge. Earlier in this testimony, I proposed to disallow $1,001,014 of this cost due to a lease expiration, so that if my revenue requirement recommendation is adopted, only $150,166 of these costs would remain to be reclassified.

Q Will you discuss the theoretical basis for your proposal to change the classification of revenues received from surplus energy sales?

A The classification of revenue for surplus sales should include a significant demand component. The profits from interchange are caused by far more than fuel costs. They are dependent on the existence of unused generating capacity. This generating capacity is paid for on a demand-related basis. By allocating these revenues back to customers on an energy-related basis, more of the revenues are allocated to higher load factor customers, even though the high energy demands of higher load factor customers actually reduce the amount of interchange sales by reducing the amount of unused generating capacity that could be used to make these sales.

Q How specifically would you propose to classify these revenues in this case?

I recommend allocating an amount equal to the average fuel costs of AECC's thermal resources in 2003 ($14.47/MWh) by energy (to compensate for the energy used to produce the power) and would allocate the remainder above the average fuel cost proportional to the sum of all demand and energy costs associated with AECC's power generation facilities. Using data in AG DR 4-2, I calculate that 41.83% of the cost of surplus sales is fuel cost. The remaining 58.17% is net revenue. I allocate this net revenue by the sum of demand and energy for the costs of the power generation facilities owned by AECC (including O&M, depreciation, interest and margin). I calculate that this cost is 27.2% demand related (after all of my other adjustments).[8] Multiplying the demand-related portion of system costs by the net revenue fraction yields a demand related portion of power sales revenues of 16.27%, which moves $7,985,459 of revenue from energy to demand.

AECC's shift of costs from energy to demand was in fact originally designed to accomplish this end by transferring profits from economy energy sales from energy to demand. (Testimony of Forest Kessenger in Docket 84-084-U, p. 3)

Q Are you proposing to remove economy energy sales from the fuel adjustment clause in light of your classification of some of these revenues as demand-related?

A No. These revenue streams are quite variable and the fuel rate is a good place to capture them for distribution co-ops and their ratepayers on a recorded basis. While the allocation of 100% of these revenues to energy is not technically correct, it is a reasonable first approximation that should continue to be used between rate cases.

[8] The figure is 29.6% using AECC's allocations on Schedule G-5-1-A.

I am only recommending that in a base rate case like this one, the revenues from interchange profits be classified properly when setting demand and energy charges.

Q Will you discuss the amortization of debt expenses in Account 428?

A AECC has classified them as 100% related to generation demand. I believe that they should be classified to generation demand, generation energy, and transmission in the same way as interest expenses have been classified, since they are a debt-related expense. I have therefore classified about 3% of these costs ($83,778) to transmission. I have classified the remaining generation-related costs 24.42% to energy and 75.58% to demand. This is identical to the method of classifying the underlying interest costs (described in AG DR 1-11), which classifies interest costs associated with hydroelectric plant as energy-related. This shifts a further $614,064 from demand to energy.

Q How have you classified generation margin?

A I again allocate margin collected from the generation function in proportion to rate base, assigning 24.42% to energy – the same proportion as my interest allocation – to reflect hydroelectric plant. This shifts $2,997,281 from demand to energy.

Q How have you classified unassigned costs allocated to generation using the rate base allocation factor?

A Like amortization of debt expense and margin, I have classified these unassigned costs in proportion to the underlying generation rate base – 24.42% energy-related. This shifts $75,200 from demand to energy.

Q Will you discuss the classification of unassigned costs allocated to generation using the O&M payroll allocation factor?

A Costs allocated to generation using the O&M Payroll Allocator, which the Company treats as 100% demand-related, should actually be 65.89% energy-

related and 34.11% demand-related. The reason is that of AECC's generation O&M payroll, 14.1% is for its hydroelectric plants, another 14.5% is for its dispatch center, and 25.9% relate to maintenance of its steam plants and combustion turbines. All of these types of costs are classified as energy-related. Of the remaining 45.5% associated with operation of its thermal plants, 25% has been classified as energy-related since the 1980s.

The end result is that $2,954,330 of its $4,483,653 of generation payroll (65.89%) is energy-related. As AECC has $8,297,507 of Administrative and General and General Plant expenses allocated by payroll, my change in classification causes a shift of $5,467,334 from demand to energy for costs allocated by O&M payroll.

Q Will you now explain your last item, the classification of unassigned costs allocated to generation using the total revenue requirement allocation factor?

A This item is very similar to the other allocated costs. The co-op classifies all of the $4,587,224 of these costs as demand-related, while I classify the generation costs in proportion to the underlying generation revenue requirement. The total generation revenue requirement is 28.92% demand-related and 71.08% energy-related after my other adjustments, yielding a shift of $3,260,797 from demand to energy at AECC's revenue requirement. Our disallowance of electric heat promotion costs that are classified using the total revenue requirement allocation factor reduces the demand-energy shift by $410,238.

Q Will you comment on AECC's proposal to shift $12,193,697 from demand to energy?

A I certainly understand why such a shift was made in the past. This was a stipulated way of dealing with the problem that AECC's cost classification method has clearly understated the energy costs facing the co-op. Moreover, as I noted above, it was also specifically designed in part to assign as an offset to the demand component of the rate some of the profits from economy energy sales to non-members, which I believe is reasonable. Nevertheless, I believe that such a shift would no longer be necessary if the AG's cost classification were adopted.

Therefore, the net effect of the Attorney General's cost classification proposal relative to AECC's proposed rate design, including both its cost classification and its cost shift, would be to increase the energy allocation by $9,337.619 at the Co-op's revenue requirement and $7,926,367 at the AG's revenue requirement.

Q Do you have any context for your proposed changes to cost classification?

A I have generally accepted AECC's fixed-variable methods and only modified them marginally to assure a more rational structure through a reclassification of about $20 million (as opposed to AECC's $12 million shift).

But to provide some overall context, the Arkansas PSC has used the average-and-peak method extensively for its investor-owned utilities, and I support the objectives of the average and peak method. This method reflects that a utility builds its total plant to meet peak demands but chooses certain types of plant with higher capital costs and lower fuel costs (i.e., baseload) to meet average demand, so that a pure fixed-variable method is not equitable and does not reflect cost causation. In response to AUD.015.2, AECC indicated that an average and peak method would transfer about **$90 million** from demand to energy.

In that light my proposal to reclassify **$20 million** is both relatively moderate and is generally deferential to the co-op's general structure of its rate design.

Q Have you prepared a summary of your proposed cost classification?

A Yes. It is shown in Table 6.

Table 6: Attorney General's Proposed Cost Classification

	Total	Demand	Energy
Co-op Production costs	272,760,693	102,655,651	170,105,042
Co-op Demand-Energy Split	-	(12,193,698)	12,193,698
Fuel Adjustment Clause effects	(853,503)		(853,503)
Co-op Production Costs for Rate Design	271,907,190	90,461,953	181,445,237
AG classification Adjustments			
Coal Lease Rents	-	(1,151,180)	1,151,180
Power Sales Revenues	-	(7,985,459)	7,985,459
Debt Amortization Expense	(83,778)	(697,842)	614,064
Generation Margin	-	(2,977,281)	2,977,281
Unallocated Costs - Rate Base	-	(75,200)	75,200
O&M Costs O&M Payroll	-	(5,467,334)	5,467,334
Unallocated Costs -Ttotal Rev Req	-	(3,255,768)	3,255,768
Subtotal Classification Changes	(83,778)	(21,610,065)	21,526,287
Reverse Co-op Demand/Energy Shift		12,193,698	(12,193,698)
AG Production Classification, AECC Rev. Req.	271,823,412	81,045,586	190,777,827
Coal mine rent disallowance (AECC classifies as demand)			(1,001,014)
Emissions Allowance Normalization	(474,101)	(474,101)	-
2004 Demand Revenue	(2,612,685)	(2,612,685)	-
Electric Heat Promotion (TRR Allocator)	(622,600)	(212,362)	(410,238)
AG Production Costs	268,114,026	77,746,438	189,366,575
Co-op Transmission Costs	64,786,301	64,786,301	
Debt Amortization	83,778	83,778	
AG Transmission Classification	64,870,079	64,870,079	
Electric Heat Promotion (TRR Allocator)	(155,650)	(155,650)	
AG Transmission Classification and Rev. Req.	64,714,429	64,714,429	
Total Costs AG Classification, AECC Rev. Req.	336,537,841	145,760,015	190,777,827
Total Costs AG Classification and Rev. Req.	332,828,455	142,460,867	189,366,575

B. Changes in the Definition of Billing Demand

Q How would you propose to design rates to recover the demand costs?

A For Rate 1 customers, I would propose a very simple change in rate design – to shift the rate from the current billing determinants (lower of 90% of the single

peak or the average of the four summer months) to the average of the four months with the highest AECC system coincident peaks, counting the current month and previous 11 months.

The shift from four summer months to the four highest months will end up including at least one, if not two, winter months in the billing determinants. As a result, the distribution co-ops will have a lessened financial incentive to promote electric heat, because the promotion of electric heat would cause their demand bills to increase, so that they would implicitly have to pay more for winter power.

To design the demand-based rates, it would be necessary to change the billing determinants because the average of the four highest months produces a higher level of billing determinants than the current figure. The higher number of kilowatt-months means that the demand charge per kW-month would need to be reduced to collect the same revenue requirement. I estimate that in the first year of the phase-in (described below), the demand billing determinants for Rate 1 would be 4.93% higher than the current billing determinants, based on my backcasting the 2004 billing demands using my proposed method and comparing them to AECC's billing demands.

I would not propose any changes to the demand cost billing determinants for interruptible customers, which are already based on the average of the current and previous 11 months non-coincident demands and face year-round price signals.

Q Have you analyzed the impact of all of your proposals on the aggregate of the Rate 1 and interruptible classes?

A Yes. Table 7 calculates the rates under the AG's proposed rate design and revenue requirements and shows that the impacts are quite small.

Table 7: Impacts of AG's Proposed Change to Cost Classification and Demand Billing Determinants

	Co-op Revenue Requirement		AG Revenue Requirement	
Rate Design	Co-op Allocation	AG Allocation	Co-op Allocation	AG Allocation
Demand $/kW-month	$ 8.40	$ 7.55	$ 8.14	$ 7.37
Demand kW	*18,475,300*	19,337,025	18,475,300	19,337,025
Demand Revenue	$ 155,192,520	$ 145,994,539	$ 150,388,942	$ 142,513,874
Energy $/MWh	$ 22.30	$ 23.43	$ 22.30	$ 23.26
Energy MWh	*8,140,752*	8,140,752	8,140,752	8,140,752
Energy Revenue	$ 181,538,770	$ 190,737,819	$ 181,538,770	$ 189,353,892
Total revenue	$ 336,731,290	$ 336,732,358	$ 331,927,712	$ 331,867,766
Rate 1				
Demand $/kW-month	$ 8.40	$ 7.55	$ 8.14	$ 7.37
Demand kW	17,479,229	18,340,955	17,479,229	18,340,955
Demand Revenue	$ 146,825,524	$ 138,474,210	$ 142,280,924	$ 135,172,838
Energy $/MWh	$ 22.30	$ 23.43	$ 22.30	$ 23.26
Energy MWh	7,563,301	7,563,301	7,563,301	7,563,301
Energy Revenue	$ 168,661,616	$ 177,208,146	$ 168,661,616	$ 175,922,385
Total revenue	$ 315,487,139	$ 315,682,356	$ 310,942,540	$ 311,095,223
% change from co-op case		0.06%	-1.44%	-1.39%
City of Augusta				
Demand $/kW-month	$ 8.40	$ 7.55	$ 8.14	$ 7.37
Demand kW	29,860	29,860	29,860	29,860
Demand Revenue	$ 250,824	$ 225,443	$ 243,060	$ 220,068
Energy $/MWh	$ 22.30	$ 23.43	$ 22.30	$ 23.26
Energy MWh	17,672	17,672	17,672	17,672
Energy Revenue	$ 394,082	$ 414,051	$ 394,082	$ 411,047
Total revenue	$ 644,906	$ 639,494	$ 637,143	$ 631,115
% change from co-op case		-0.84%	-1.20%	-2.14%
Rates IC-1 and IC-2				
Demand $/kW-month	$ 8.40	$ 7.55	$ 8.14	$ 7.37
Demand kW	966,221	966,221	966,221	966,221
Demand Revenue	$ 8,116,256	$ 7,294,969	$ 7,865,039	$ 7,121,049
Energy $/MWh	$ 22.30	$ 23.43	$ 22.30	$ 23.26
Energy MWh	559,779	559,779	559,779	559,779
Energy Revenue	$ 12,483,072	$ 13,115,622	$ 12,483,072	$ 13,020,460
Total revenue	$ 20,599,328	$ 20,410,591	$ 20,348,111	$ 20,141,508
Less Interruptible credit	(4,251,372)	(4,251,372)	(4,251,372)	(4,251,372)
Net Revenue	$ 16,347,956	$ 16,159,218	$ 16,096,738	$ 15,890,136
% change from co-op case		-1.15%	-1.54%	-2.80%
Rounding Error	$ 37,882	$ 38,950	$ 100,352	$ 40,405

The cost classification and rate design changes result in a very small net increase in costs (0.06%) for Rate 1 and a decrease of about 1.1% for Rate IC at the Company's revenue requirement. Two offsetting factors create the change. First,

the increased classification to energy raises rate IC costs because these customers have relatively high load factors. However, the increase in demand billing determinants for Rate 1 (with no corresponding increase for Rate IC demand billing determinants) decreases Rate IC by a larger amount than the shift in cost classification from demand to energy.[9] The AG's lower revenue requirement creates about a 1% decrease for Rate 1 and 2% for Rates IC-1 and 2.

Q Have you analyzed the impact of your proposal on the individual co-ops?

A Yes. I have backcast the demand billing determinants that would have resulted in 2004 under my proposal and prepared an analysis of the resulting rates using the AG's rate design and both AECC's and the AG's revenue requirement. The results are shown in Exhibit WBM-4.

Eight co-ops would see rate increases and eight would see decreases with full implementation of the AG's proposed rate design at AECC's revenue requirement.[10] Nine of the 16 co-ops would have rate changes of less than 1%. Of the remainder, three would have decreases in excess of 2% (Ashley-Chicot, Clay County and Ozarks), two would have increases between 1 and 2%. Only two co-ops would have an increase above 2% -- North Arkansas (2.19%) and Mississippi County (5.65%). Mississippi County Co-op faces large impacts as a result of a combination of its extensive electric heat promotion[11] and load management to keep the peak down in the single coincident hour in the summer, while having relatively high peaks in other hours with loads relatively close to the peak.

With the Attorney General's revenue requirement (a decrease of about 1% from the Co-op's revenue requirement), the potential for adverse bill impacts is further reduced. Only three co-ops would see increases relative to current rates, and only Mississippi County's increase would exceed 1%.

[9] If the Commission wanted to make this proposal revenue-neutral between Rate 1 and Rate IC, it could reduce the interruptible credit for rate IC slightly (on the order of 10 cents/kW-month).

[10] This discussion refers only to Rate 1 firm loads. All Rate IC-1 and 2 loads would receive small decreases.

[11] It has the largest differential between first block and tailblock on the AECC system of 3.5 cents/kWh.

Q Could your proposed rate design could be phased in to limit impacts on distribution co-ops who might otherwise see significant rate increases?

A Yes. I would recommend a phase-in where the demand billing determinant for any given month is set at the maximum of average of the four highest months and an percentage of the current summer-oriented billing determinant for that month. The percentage of the current billing determinant would be increased over a three-year period, and in the fourth year, the new rate design would apply to all co-ops.

I have designed my proposed rates based on my first year phase-in percentage where the billing demand is based on the lesser of 110% of the current billing demand or the average of the four highest months. This phase-in would provide limited amounts of relief for several of the co-ops with rate increases over 1%. The figure would be increased to 113% in year 2 and 116% in year 3. The year 2 and year 3 phase-ins would only apply to Mississippi County and would increase its rates by about 0.8% per year.

Q Would there need to be rate changes to offset revenue impacts of the phase-in?

A As a matter of practicality, and given that AECC is not expected to return to the Commission for any other rate change, no. If one factored the change in billing determinants due to the phase-in to design the rates, the difference between the first year of the phase-in and rates applicable at the end of the process rounds to a change in the demand charge of 1 cent per kilowatt-month. The Company would receive $265,000 (less than 0.1%) more at the end of the phase-in than at the beginning, holding billing determinants constant at hypothetical 2004 levels.

Q Will you summarize the effects of your proposed rate design?

A With very little cost impact on both the distribution co-ops and their interruptible customers, the Commission has a chance to send much better and more rational price signals through the wholesale rates charged by AECC.

The rate design recommended by the Attorney General will give decreases to half of the co-ops, small increases to six of the 16 co-ops, and raise rates for only two of the 16 co-ops by more than 2%. The increases can be mitigated through a phase-in to prevent rate shock as well as by the small reductions which the AG proposes to the Co-op's revenue requirement (as well as any cost reductions identified by Staff).[12] The AG's proposal will also reduce interruptible customers' rates in Rate classes IC-1 and IC-2 by about 1% relative to the system average.

In exchange for these relatively modest shifts, the wholesale rates will begin to send price signals that electric heat promotion is costly. While shoulder month power (April, May, October, and November) remains cheap since none of these months will ever be among the four highest, the distribution co-ops would receive price signals regarding both the summer and winter peaks. Any of the months of June-September and December-March could be one of the top 4 months (though September and March are less likely than the others). The price signal with two summer peak months and two winter peak months would be about 4.8 cents/kWh during four-month summer and winter seasons with only the shoulder having a cost signal equal to the energy cost. Since electric heat loads tend to be highly coincident with the winter peak, this rate shift would also give co-ops incentives over time to reduce or eliminate declining block rate structures that reward large winter space heating power users who use disproportionate amounts of power coincident with the monthly system peak.

Q Do you have any concluding remarks?

A Yes. The Commission has the chance to stop the unreasonable promotion of electric heat at prices well below the incremental cost of electricity. This promotion of electric heat creates a new winter peak, causes the rates charged by AECC to every distribution co-op to rise, has the potential for raising gas rates for other Arkansas customers across the state, and increases emissions of greenhouse

[12] At the AG's revenue requirement, only three of 16 co-ops would receive rate increases, and only one (Mississippi County (4.67%), would receive an increase above 1%.

gases and other pollutants. Promoting electric heat is simply unsustainable in all respects.

The simple change to the demand cost allocation method recommended by the Attorney General can promote the public interest by moving the distribution co-ops, who respond to AECC's price signals, away from the costly promotion of electric heat.

I encourage the Commission to take this simple but important step.

Q Does this complete your testimony, Mr. Marcus?

A Yes, it does. Thank you.

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS ELECTRIC CO-OPERATIVE CORPORATION FOR APPROVAL OF CHANGES IN ITS WHOLESALE POWER RATES TO ITS MEMBERS	)	Docket 04-141-U

PREPARED EXHIBITS OF WILLIAM B. MARCUS

on behalf of

THE ATTORNEY GENERAL

March 8, 2005

List of Exhibits

WBM-1	Qualifications of William B. Marcus
WBM-2	AECC Response to Staff Data Requests AUD.15.1 and AUD.15.2
WBM-3	Data and Graphs on Monthly Peak and Energy Loads for Rate 1 and Other Rate Schedules, 1998-2004
WBM-4	Impact of the Attorney General's Cost Classification and Rate Design on Individual Distribution Co-ops and Interruptible Customers
WBM-5	Distribution Co-op Web Pages Promoting Heat Pumps

Exhibit WBM-1 Qualifications of William B. Marcus

William B. Marcus

Principal Economist,
JBS Energy, Inc.

William B. Marcus, Principal Economist, has 25 years of experience in electric and gas utility issues.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July, 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the Company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation. He has analyzed restructuring and stranded cost issues in eight states and provinces for consumer, environmental, and independent power clients.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court, legislative committees in Ontario and California, the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Manitoba, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, other revenue issues, avoided cost, and electric and gas cost of service and rate design.

From 1975 to 1978, Mr. Marcus was a research analyst at the Kennedy School of Government, Harvard University.

From July, 1978 through April, 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared testimony on purchased power pricing and economic studies of transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April, 1982, through June, 1984, he was the principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics and resources.

Mr. Marcus served on the 1991-92 SMUD Rate Advisory Committee, which made cost allocation and rate design recommendations to the SMUD Board. He serves on advisory committees for Woodland Community College and the City of Woodland, California.

Exhibit WBM-2 AECC Response to Staff Data Requests AUD.15.1 and AUD.15.2

APSC DATA REQUEST
AUD-015.1
DOCKET NO. 04-141-U

Question:

Please reference the Direct Testimony of Robert Shields filed in this docket on October 15, 2004. The statement, "The (AECC) Board has decided to proceed with a change in wholesale rates and voted to file with the Commission a Rate Application and supporting Cost of Service Study," is made on page 1, lines 15-17. This statement indicates that the Board has an underlying objective in altering rates. Please outline the Board's objective in designing rates. Please include information on the Board's desired outcome as it pertains to rate design as well as the Board's reasoning behind this outcome.

AECC's Response:

Objective of the rate filing:

The decision of AECC's Board to proceed with a change in wholesale rates was a straightforward decision to increase operating revenues. AECC's Board believes that AECC's rates must be sufficient to maintain a strong margin, maintain necessary long term equity, provide for future plant, borrow at reasonable and competitive lending rates, and allocate and retire capital credits. There is nothing new in this strategy. AECC established these objectives before the Arkansas Public Service Commission in Docket 90-096-U.

AECC's rate design objectives have remained constant for over 25 years. AECC first began using a wholesale rate design based on each distribution cooperative's contribution to AECC's coincident peak(s) in 1978. During this same period, AECC has allocated fixed costs to demand and variable costs to energy. This basic rate methodology for collecting demand and energy costs has continued until the present time. With three exceptions in this proceeding (fixed hydroelectric generation, system control and load dispatch, and an approximate $12 million transfer – a transfer also occurred in Docket 90-096-U), AECC has allocated fixed costs to demand and variable costs to energy. The justification for allocating the three fixed cost items to energy has been well documented and supported in AECC's Direct Testimony and in AECC's response to numerous Data Requests.

AECC's proposed rate design accomplishes many desirable objectives and, in some similar fashion, has served AECC well since 1978. AECC's rate design objectives closely tie to many of the rate criteria established by James Bonbright in his Principles of Public Utility Rates. Some of AECC's rate design objectives are as follows:

1. To obtain adequate margins and the necessary long-term equity to provide a reliable source of self-owned wholesale power supply at a reasonable long term

cost. AECC's Board recognizes that this objective is best met through long-term economic decision-making.

2. One rate for all members.

3. Similar past rate designs have provided AECC with reasonable rate stability. AECC has not requested a wholesale rate increase since 1984.

   An additional advantage of the proposed rate design is that AECC's member cooperatives currently offer retail rates based on AECC's wholesale rate design. AECC's members are reluctant to alter AECC's rate structure because of its possible impact on their existing retail rates. If the Commission approves AECC's proposed rate design, the increase may easily be passed on to retail members through the U-2811 process without radical and upsetting changes to retail members.

4. By traditionally placing fixed costs in AECC's demand charge and variable costs in its energy charge, AECC has sent a proper, cost based, wholesale price signal. The fixed cost of generation and transmission are most radically affected when new plant is acquired. New plant investment is often mandated by the on peak demand for electricity. If demand is priced in such a way as to signal the cost of capacity, then there is a direct price signal.

   This price signal has led to extensive peak shaving efforts on the part of AECC's distribution cooperatives and in the successful offering of AECC's IC (interruptible credit) rates. These efforts have forestalled the building of peaking capacity.

   AECC's energy charge is primarily driven by costs that vary with kWh production. If AECC is not in an on peak period, it is reasonable for members to be charged the variable cost of production associated with their kWh consumption. This variable kWh charge encourages off peak load building, load factor improvement, and a lower average cost per kWh consumed.

5. The proposed or a similar rate design has provided AECC's members with a fair and equitable compromise between high load factor and low load factor distribution cooperatives. This compromise has been developed over a 25-year period. It has allowed high load factor cooperatives to take advantage of a rate design using coincident peaks. It has allowed many low load factor cooperatives (particularly cooperatives with irrigation loads) to put in place a load management system that has improved their load factors and equalized their cost of wholesale service.

   Unlike past rate increase proceedings in the late 1970s and early 1980s, there has been little controversy among AECC's Board and, to date, no distribution cooperative has intervened in this Docket.

APSC DATA REQUEST
AUD-015.2
DOCKET NO. 04-141

Question:

Please reference AECC's response to the data request AUD-005.2. With the exception of the allocation of the System Control and Load Dispatching costs, Hydro Plant costs, and the $12.2 million transfer from demand to energy, AECC has generally followed a cost accounting method of allocating between demand and energy, where fixed costs are allocated to demand and variable costs are allocated to energy. The NARUC Electric Utility Cost Allocation Manual (January 1992) has identified another method of cost classification, cost causation "attempts to determine what influences a utility's production plant investment decision." Furthermore, the NARUC Manual on pg. 57 states that considering that "energy loads are an important determinant of production plant costs," use of the average and peak demand method is one means by which to incorporate "judgmentally-established energy weighting into cost studies." Please discuss how the use of an alternative method that takes into account energy weighting such as the average and peak method would have changed AECC's final demand and energy allocations. Please discuss the magnitude of the impact such an alternative method would have on demand and energy allocations based on AECC's chosen method.

AECC's Response:

AECC's Board of Directors is aware that there is more than one way to allocate costs between demand and energy and to design a rate. Being aware of this, and having long experience in rate making (both as AECC directors and as managers and directors at their respective distribution cooperatives), AECC's Board selected the cost allocation and rate design methodology that was best for AECC. In doing this, AECC's Board made a management decision to transfer approximately $12 million from demand to energy. The reasoning behind this decision is supported in AECC's Direct Testimony and in AECC's response to AUD-005.2. No rate design is perfect, but the rate design proposed by AECC in this Docket has many advantages. These advantages are outlined in AECC's response to AUD-015.1. However, one possible short coming of AECC's proposed filed rate design is that consumers who are off line during AECC's coincident peak(s) will not pay for any capacity costs. In the view of AECC's Board, all consumers should contribute some dollars to capacity costs. The $12 million dollar transfer from demand to energy is the method chosen to accomplish this goal. While the amount transferred was a Board decision, there are at least two rate formulas which would also accomplish a transfer from demand to energy. These methodologies are called average and excess and average and peak.

The following information is being provided in response to the General Staff's Data Request AUD-015.2. This information is offered for response purposes only. It does not alter AECC's filed position and only represents approximations using certain assumptions.

Average and Excess:

The average and excess rate was first documented by W. J. Green in a 1925 article published in *Electric World* magazine. Using an average and excess methodology for calculating AECC's rate, and given the assumptions noted below, over $22 million would be transferred from demand to energy costs.

While the average and excess billing methodology would have the advantage of a demand to energy transfer, the transfer would be more than AECC's Board desires. A major disadvantage of the average and excess methodology is that it uses non-coincident peaks. A non-coincident rate design would leave no incentive for member's to avoid AECC's coincident peak. If there is no incentive to avoid AECC's coincident peak, then peak shaving efforts would be obsolete. AECC would be in the position of acquiring peaking capacity for loads that are currently being controlled, either directly by a cooperative or through a retail member's own initiative. This rate design is not desired by AECC's Board.

Note:

For the average and excess calculation, AECC defined the non-coincident billing demand as the highest monthly non-coincident demand incurred by each cooperative during the current month or the previous eleven months (December 2003 was chosen as the current month). These cooperative non-coincident peaks are then summed to form a total AECC non-coincident peak for use in the formula. In addition, AECC left the interruptible credit at $4.40. Under any new rate design, the credit would have to be reevaluated.

Average and Peak:

As applied by OG&E and Entergy in APSC Dockets 98-036-U and 96-360-U respectively, the average and peak methodology allocates a predetermined demand allocation among various customer classes using a system load factor and a system coincidence factor. Because AECC is not a fully integrated utility and has only one class of consumer (16 member cooperatives), the average and peak methodology cannot be used to assign demand costs to various classes of customer. It is possible to accomplish the same result by manipulating the average and peak methodology to increase the energy charge, however. If the average and peak methodology were applied to AECC loads, the transfer from demand to energy would be approximately $90 million.

Note:

For the average and peak calculation, AECC defined the coincident billing demand as the highest monthly coincident demand incurred by AECC during the current month or the previous eleven months (December 2003 was chosen as the current month). In addition, AECC allowed the interruptible credit to remain at $4.40. Under any new rate design, the amount of the credit would have to be reevaluated.

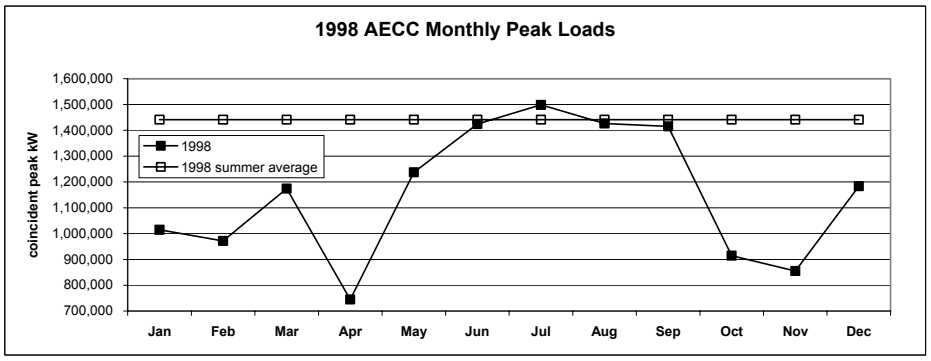
Advantages of AECC's $12 Million Transfer vs. Other Methodologies:

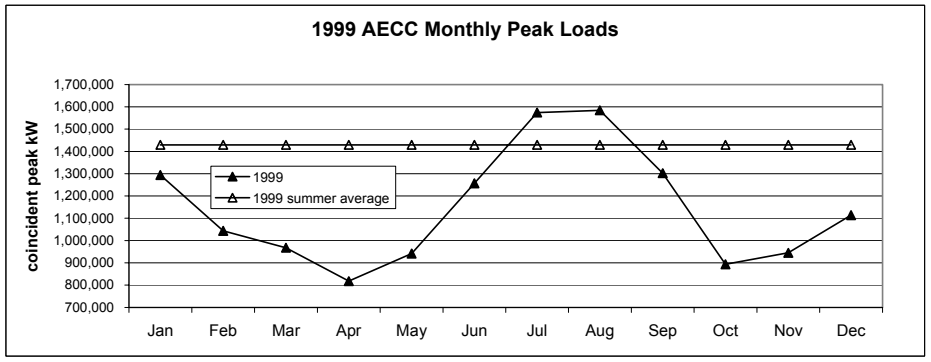
By transferring only $12 million from demand to energy, AECC stopped short of the transfer derived under the average and excess or the average and peak methodology. By transferring $12 million, AECC accomplished the benefits previously described in its Direct Testimony and in its response to AUD-005.2. AECC's proposed rate design provides a greater incentive for distribution cooperatives to improve their load factors and to minimize loads during on-peak periods than either the average and excess method or the average and peak method.

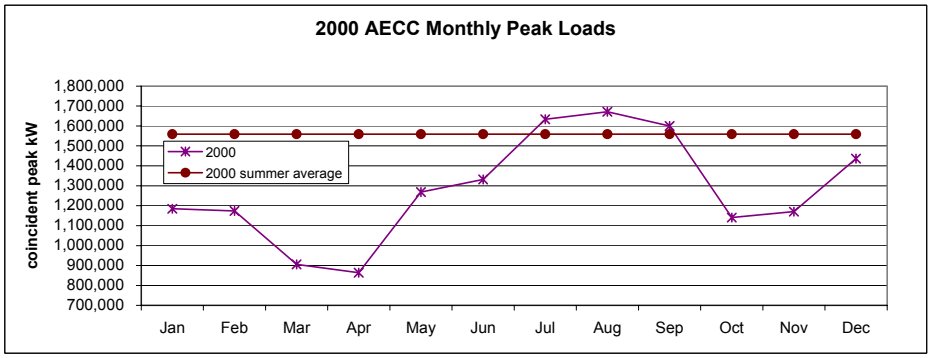
In addition, AECC's distribution cooperatives have built their retail rates around designs similar to AECC's proposed rate design for many years. By maintaining a similar rate design, the rate increase effect is minimized to the distribution cooperatives' various classes of service.

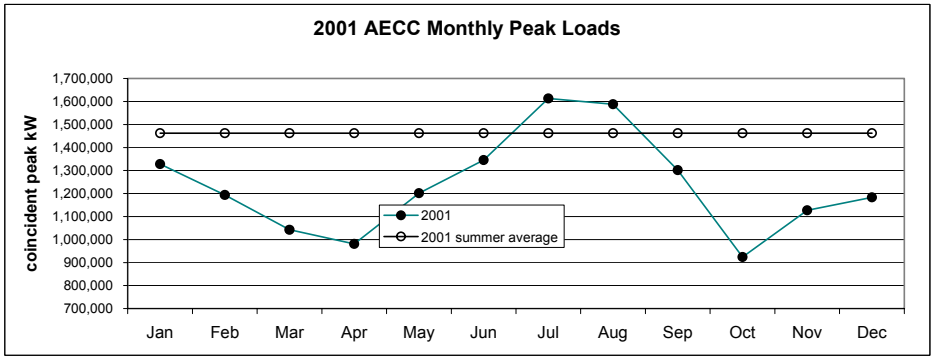
Exhibit WBM-3 **Data and Graphs on Monthly Peak and Energy Loads for Rate 1 and Other Rate Schedules, 1998-2004**

Rate 1 Peak Loads

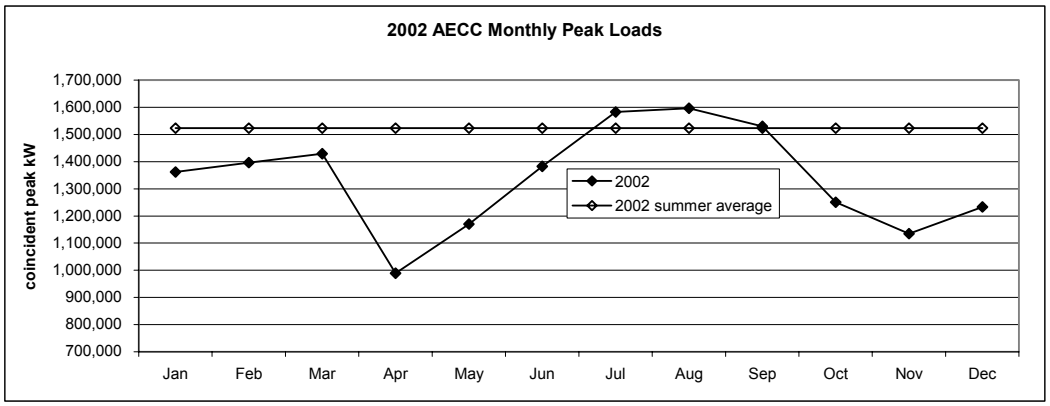


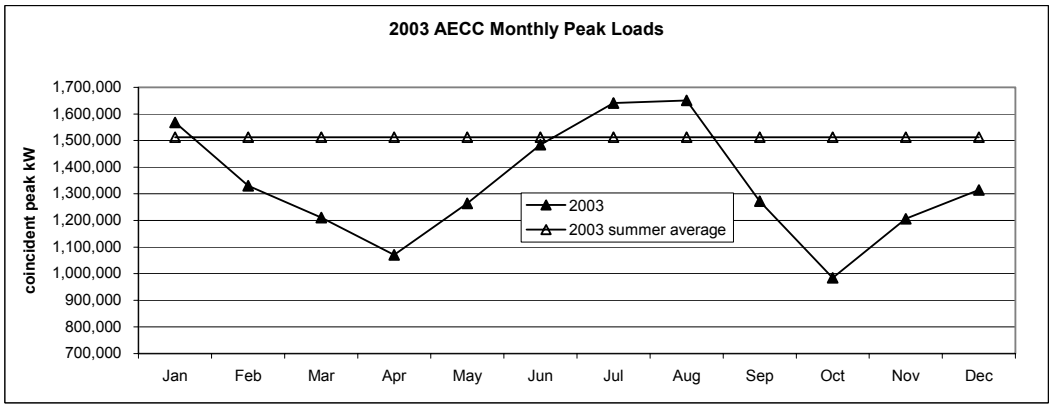


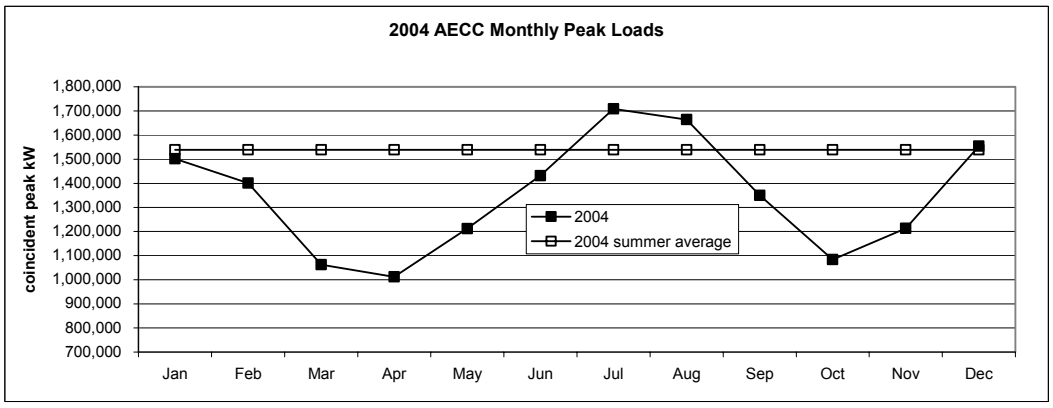




Rate 1 Peak Loads







kilowatt-hours

Rate 1	1998	1999	2000	2001	2002	2003	2004
Jan	517,715,813	574,452,167	581,579,805	679,871,211	641,398,404	726,283,713	706,750,405
Feb	445,608,424	443,590,585	492,037,179	535,895,619	566,088,860	629,338,657	658,597,395
Mar	496,836,922	490,322,141	471,943,790	538,600,943	577,095,671	555,955,860	533,531,371
Apr	395,415,724	413,294,122	427,940,344	458,053,051	486,013,541	483,357,899	492,572,109
May	514,877,863	457,667,802	512,451,741	524,157,077	516,142,658	542,508,446	588,478,041
Jun	671,522,752	597,466,318	602,991,328	640,168,813	683,865,826	623,040,232	680,249,162
Jul	786,049,976	789,766,809	786,469,259	846,006,078	813,957,077	841,643,647	791,644,918
Aug	701,281,112	772,220,438	868,027,001	799,444,202	801,463,788	838,129,280	742,302,449
Sep	605,355,047	536,968,963	616,385,153	569,670,146	649,291,815	574,418,798	648,573,267
Oct	441,944,414	462,843,350	506,941,588	498,069,018	529,838,571	519,829,109	551,611,472
Nov	435,421,163	447,440,399	554,834,579	497,257,669	561,659,964	550,554,372	552,932,563
Dec	552,441,874	558,885,992	722,860,284	601,815,331	649,685,689	678,557,111	730,340,402
Total	6,565,570,610	6,544,912,746	7,144,462,051	7,189,009,158	7,476,501,864	7,617,191,685	7,733,381,247
4 Summer	2,764,208,887	2,696,422,528	2,873,872,741	2,855,289,239	2,948,578,506	2,877,231,957	2,862,769,796
3 Winter	1,515,766,111	1,576,928,744	1,796,477,268	1,817,582,161	1,857,172,953	2,034,179,481	2,095,688,202
5 Shoulder	2,285,595,612	2,271,561,474	2,474,112,042	2,516,137,758	2,670,750,405	2,705,780,247	2,774,923,249

IC 1	1998	1999	2000	2001	2002	2003	2004
Jan	48,222,916	46,425,425	48,577,421	43,953,584	42,510,901	41,597,703	44,120,811
Feb	44,066,631	42,384,175	47,188,988	41,706,068	39,014,643	38,587,353	42,592,027
Mar	48,636,810	48,143,633	51,278,377	41,076,539	41,257,796	42,045,702	45,985,517
Apr	47,492,940	43,892,883	50,524,703	44,586,580	42,123,242	42,696,187	45,098,437
May	49,156,148	50,539,318	52,834,233	46,918,247	43,450,002	35,716,904	46,542,625
Jun	42,017,352	50,586,076	44,456,777	44,941,923	43,035,232	43,541,211	43,257,756
Jul	51,673,878	52,327,242	46,016,496	37,996,265	41,357,605	46,980,537	46,996,967
Aug	49,285,142	53,105,740	47,525,727	47,917,424	45,710,577	47,376,569	47,334,777
Sep	48,178,108	50,407,188	44,455,588	43,204,323	43,564,742	44,191,214	45,605,306
Oct	48,602,844	51,897,200	45,992,355	44,071,344	44,010,325	45,178,939	46,718,270
Nov	45,195,746	48,946,466	43,361,067	33,742,353	40,040,833	37,364,302	43,287,220
Dec	46,725,514	49,587,584	42,386,260	38,162,263	39,544,084	40,927,821	39,522,116
Total	569,254,029	588,242,930	564,597,992	508,276,913	505,619,982	506,204,442	537,061,829

IC 2	1998	1999	2000	2001	2002	2003	2004
Jan	4,671,445	4,649,996	4,446,285	4,596,225	4,263,137	4,470,047	4,882,225
Feb	4,225,395	3,946,913	3,854,122	4,225,873	3,853,058	4,064,681	4,595,083
Mar	4,647,240	4,716,356	2,314,124	4,503,219	4,317,858	4,124,128	4,445,414
Apr	4,458,394	4,635,809	2,499,950	4,543,339	4,240,453	4,199,969	4,578,989
May	4,694,100	2,540,483	4,687,910	4,693,408	4,415,426	4,331,488	4,584,244
Jun	4,621,801	4,678,642	4,594,419	4,372,693	4,248,271	4,160,842	4,454,382
Jul	4,474,231	4,356,057	4,690,587	4,713,799	4,435,604	4,838,043	4,858,699
Aug	4,529,530	4,357,221	4,677,585	4,479,957	4,435,339	4,465,756	4,903,631
Sep	4,496,558	4,448,813	4,427,707	3,519,792	4,198,020	4,315,523	4,660,542
Oct	4,576,019	4,684,083	4,750,735	4,385,702	4,353,765	4,941,865	4,757,724
Nov	4,324,577	4,592,876	4,492,981	4,175,908	4,236,947	4,783,357	4,573,805
Dec	4,551,957	4,475,688	4,572,206	4,080,667	4,224,717	4,878,862	4,502,955
Total	54,271,247	52,082,937	50,008,611	52,290,582	51,222,595	53,574,561	55,797,693

Rates 1 IC1&2	1998	1999	2000	2001	2002	2003	2004
Jan	570,610,174	625,527,588	634,603,511	728,421,020	688,172,442	772,351,463	755,753,441
Feb	493,900,450	489,921,673	543,080,289	581,827,560	608,956,561	671,990,691	705,784,505
Mar	550,120,972	543,182,130	525,536,291	584,180,701	622,671,325	602,125,690	583,962,302
Apr	447,367,058	461,822,814	480,964,997	507,182,970	532,377,236	530,254,055	542,249,535
May	568,728,111	510,747,603	569,973,884	575,768,732	564,008,086	582,556,838	639,604,910
Jun	718,161,905	652,731,036	652,042,524	689,483,429	731,149,329	670,742,285	727,961,300
Jul	842,198,085	846,450,108	837,176,342	888,716,142	859,750,286	893,462,227	843,500,584
Aug	755,095,784	829,683,399	920,230,313	851,841,583	851,609,704	889,971,605	794,540,857
Sep	658,029,713	591,824,964	665,268,448	616,394,261	697,054,577	622,925,535	698,839,115
Oct	495,123,277	519,424,633	557,684,678	546,526,064	578,202,661	569,949,913	603,087,466
Nov	484,941,486	500,979,741	602,688,627	535,175,930	605,937,744	592,702,031	600,793,588
Dec	603,719,345	612,949,264	769,818,750	644,058,261	693,454,490	724,363,794	774,365,473
Total	7,189,095,886	7,185,238,613	7,759,068,654	7,749,576,653	8,033,344,441	8,123,396,127	8,270,443,076

Nucor Yamato	1998	1999	2000	2001	2002	2003	2004
Jan	121,484,812	116,889,918	124,854,309	122,769,936	112,385,092	99,402,495	116,549,096
Feb	107,338,703	107,668,133	116,747,678	108,919,596	108,537,848	90,068,447	112,227,450
Mar	92,961,095	74,985,373	97,308,054	91,772,438	85,634,103	78,090,784	89,891,123
Apr	109,204,068	115,965,356	121,429,844	108,603,983	114,539,470	103,152,787	116,963,147
May	118,934,667	107,169,201	119,537,088	91,225,261	115,965,461	94,599,444	117,147,460
Jun	109,232,793	118,610,530	114,701,127	89,013,458	110,289,689	112,586,615	115,626,028
Jul	108,421,197	106,188,928	122,830,528	111,693,128	101,124,585	107,363,695	112,025,120
Aug	115,277,336	118,107,550	122,350,520	105,125,866	94,542,415	113,536,847	116,282,059
Sep	82,676,062	76,693,752	91,149,736	74,793,311	71,355,119	82,079,290	74,665,114
Oct	120,910,866	120,330,972	116,078,193	109,953,747	98,433,275	110,719,376	115,145,123
Nov	106,243,129	108,679,264	113,840,025	97,260,180	99,349,773	102,451,298	105,074,009
Dec	104,458,482	109,533,958	113,176,584	99,951,418	96,495,570	112,745,459	95,289,945
Total	1,297,143,210	1,280,822,935	1,374,003,686	1,211,082,322	1,208,652,400	1,206,796,537	1,286,885,674

Nucor Steel	1998	1999	2000	2001	2002	2003	2004
Jan	108,493,886	102,978,486	123,800,414	110,751,077	116,619,882	110,911,428	141,204,613
Feb	97,385,647	103,111,717	106,887,039	103,192,377	115,608,164	107,632,034	132,423,391
Mar	112,226,291	108,021,464	123,049,541	128,242,677	127,220,916	128,586,646	135,262,622
Apr	102,564,343	104,068,992	114,860,807	120,276,776	124,654,016	119,488,445	141,615,787
May	112,325,897	116,977,529	108,785,989	126,682,663	119,700,805	120,211,964	140,761,049
Jun	95,871,814	105,183,271	101,337,885	114,596,019	127,047,904	125,464,059	138,859,813
Jul	60,052,655	109,029,415	109,422,854	125,428,985	115,222,100	127,382,276	112,236,124
Aug	88,702,853	105,040,836	97,279,304	109,899,618	125,287,222	125,110,975	139,098,842
Sep	67,852,312	112,918,197	100,837,906	120,100,173	118,319,553	131,029,132	134,641,373
Oct	60,583,754	112,856,183	113,776,076	116,240,426	121,896,892	125,973,436	134,370,820
Nov	71,086,426	120,325,022	102,991,160	104,909,551	120,883,448	114,674,693	108,984,670
Dec	97,879,423	102,562,510	101,656,440	115,001,317	112,042,530	131,696,090	126,717,021
Total	1,075,025,301	1,303,073,622	1,304,685,415	1,395,321,659	1,444,503,432	1,468,161,178	1,586,176,125

	1998	1999	2000	2001	2002	2003	2004
SYSTEM							
Jan	800,588,872	845,395,992	883,258,234	961,942,033	917,177,416	982,665,386	1013507150
Feb	698,624,800	700,701,523	766,715,006	793,939,533	833,102,573	869,691,172	950435346
Mar	755,308,358	726,188,967	745,893,886	804,195,816	835,526,344	808,803,120	809116047
Apr	659,135,469	681,857,162	717,255,648	736,063,729	771,570,722	752,895,287	800828469
May	799,988,675	734,894,333	798,296,961	793,676,656	799,674,352	797,368,246	897513419
Jun	923,266,512	876,524,837	868,081,536	893,092,906	968,486,922	908,792,959	982447141
Jul	1,010,671,937	1,061,668,451	1,069,429,724	1,125,838,255	1,076,096,971	1,128,208,198	1067761828
Aug	959,075,973	1,052,831,785	1,139,860,137	1,066,867,067	1,071,439,341	1,128,619,427	1049921758
Sep	808,558,087	781,436,913	857,256,090	811,287,745	886,729,249	836,033,957	908145602
Oct	676,617,897	752,611,788	787,538,947	772,720,237	798,532,828	806,642,725	852603409
Nov	662,271,041	729,984,027	819,519,812	737,345,661	826,170,965	809,828,022	814852267
Dec	806,057,250	825,045,732	984,651,774	859,010,996	901,992,590	968,805,343	996372439
Total	9,560,164,871	9,769,141,510	10,437,757,755	10,355,980,634	10,686,500,273	10,798,353,842	11,143,504,875

Exhibit WBM-3

kilowatt-months coincident peak demand

Rate 1	1998	1999	2000	2001	2002	2003	2004
Jan	1,014,682	1,293,815	1,184,625	1,328,079	1,361,962	1,573,931	1,507,863
Feb	971,805	1,043,537	1,173,900	1,193,769	1,396,105	1,336,709	1,406,925
Mar	1,174,432	968,078	905,633	1,042,602	1,429,163	1,216,604	1,069,709
Apr	745,006	817,983	864,217	980,668	988,812	1,076,318	1,018,711
May	1,237,363	941,633	1,267,998	1,201,722	1,169,878	1,270,157	1,218,044
Jun	1,424,101	1,257,084	1,331,802	1,345,867	1,382,514	1,490,659	1,437,638
Jul	1,498,666	1,574,160	1,633,352	1,613,407	1,582,951	1,647,168	1,715,071
Aug	1,426,547	1,584,575	1,671,132	1,588,516	1,596,694	1,657,089	1,670,387
Sep	1,415,111	1,302,335	1,600,062	1,301,989	1,530,275	1,278,098	1,356,899
Oct	914,727	893,551	1,140,352	923,899	1,250,120	991,346	1,090,641
Nov	855,257	945,171	1,170,036	1,126,968	1,134,984	1,212,801	1,219,741
Dec	1,183,505	1,113,597	1,436,539	1,183,515	1,233,556	1,320,497	1,559,871
Total	13,861,202	13,735,519	15,379,648	14,831,001	16,057,014	16,071,377	16,271,500
4 Summer	5,764,425	5,718,154	6,236,348	5,849,779	6,092,434	6,073,014	6,179,995
3 Winter	3,169,992	3,450,949	3,795,064	3,705,363	3,991,623	4,231,137	4,474,659
5 Shoulder	4,926,785	4,566,416	5,348,236	5,275,859	5,972,957	5,767,226	5,616,846

IC 1	1998	1999	2000	2001	2002	2003	2004
Jan	70,630	63,467	66,721	67,758	63,472	59,314	62,234
Feb	68,463	60,650	64,577	63,550	60,513	53,162	59,426
Mar	68,552	60,595	64,705	39,724	56,497	61,313	58,514
Apr	63,872	70,063	58,901	63,876	60,560	56,405	60,476
May	56,313	66,066	81,670	70,933	62,157	58,978	63,841
Jun	64,119	72,732	58,236	66,397	62,584	67,777	51,103
Jul	74,508	73,665	67,674	44,443	66,381	68,176	67,905
Aug	66,130	76,750	66,293	66,357	58,533	67,213	63,225
Sep	69,280	61,133	55,336	56,891	65,167	73,478	68,482
Oct	61,996	80,829	64,855	57,965	61,658	56,971	66,597
Nov	63,063	71,507	63,283	49,747	53,232	37,476	57,838
Dec	63,307	69,012	66,960	38,712	55,366	61,390	52,982
Total	790,233	826,469	779,211	686,353	726,120	721,653	732,623

IC 2	1998	1999	2000	2001	2002	2003	2004
Jan	6,234	6,355	179	6,248	5,862	6,198	6,540
Feb	6,262	5,919	164	6,305	5,712	6,148	6,554
Mar	6,283	6,383	6,312	6,283	5,883	6,033	6,769
Apr	6,362	6,412	164	6,533	5,969	5,755	6,347
May	6,476	6,405	6,340	6,369	5,983	5,919	5,698
Jun	6,455	6,296	6,405	6,098	5,955	5,998	6,183
Jul	6,476	135	6,412	6,526	6,048	6,569	6,647
Aug	4,241	213	6,469	6,055	6,012	6,033	6,669
Sep	6,219	6,169	6,426	6,062	6,040	5,998	6,626
Oct	6,319	6,326	6,426	5,962	6,026	6,676	6,469
Nov	6,133	6,355	6,226	5,841	5,869	6,583	6,383
Dec	6,355	6,412	6,212	5,783	6,012	6,159	6,033
Total	73,815	63,380	57,735	74,065	71,371	74,069	76,918

Rates 1 IC1&2	1998	1999	2000	2001	2002	2003	2004
Jan	1,091,546	1,363,637	1,251,525	1,402,085	1,431,296	1,633,245	1,570,097
Feb	1,046,530	1,110,106	1,238,641	1,263,624	1,462,330	1,389,871	1,466,351
Mar	1,249,267	1,035,056	976,650	1,088,609	1,491,543	1,277,917	1,128,223
Apr	815,240	894,458	923,282	1,051,077	1,055,341	1,132,723	1,079,187
May	1,300,152	1,014,104	1,356,008	1,279,024	1,238,018	1,329,135	1,281,885
Jun	1,494,675	1,336,112	1,396,443	1,418,362	1,451,053	1,558,436	1,488,741
Jul	1,579,650	1,647,960	1,707,438	1,664,376	1,655,380	1,715,344	1,782,976
Aug	1,496,918	1,661,538	1,743,894	1,660,928	1,661,239	1,724,302	1,733,612
Sep	1,490,610	1,369,637	1,661,824	1,364,942	1,601,482	1,351,576	1,425,381
Oct	983,042	980,706	1,211,633	987,826	1,317,804	1,048,317	1,157,238
Nov	924,453	1,023,033	1,239,545	1,182,556	1,194,085	1,250,277	1,277,579
Dec	1,253,167	1,189,021	1,509,711	1,228,010	1,294,934	1,381,887	1,612,853
Total	14,725,250	14,625,368	16,216,594	15,591,419	16,854,505	16,793,030	17,004,123

Exhibit WBM-3

Nucor Yamato	1998	1999	2000	2001	2002	2003	2004
Jan	169,939	179,118	183,344	16,727	176,184	106,236	182,349
Feb	165,454	164,032	178,519	188,870	191,052	78,643	98,988
Mar	139,057	164,089	17,380	165,494	114,179	123,107	185,606
Apr	174,843	181,776	191,924	193,718	121,200	172,508	178,059
May	117,871	165,163	192,183	182,026	102,260	185,403	96,281
Jun	110,187	154,910	110,930	183,432	99,804	81,762	122,824
Jul	171,498	36,918	123,874	103,909	112,627	162,844	147,476
Aug	115,269	88,064	177,162	124,674	102,883	137,311	180,943
Sep	130,250	146,305	188,345	118,654	112,724	135,703	9,858
Oct	147,581	180,127	165,083	170,205	114,122	185,137	189,589
Nov	166,876	176,589	178,027	186,753	194,736	149,173	167,425
Dec	163,168	180,289	193,637	189,427	185,267	191,868	164,185
Total	1,771,993	1,817,380	1,900,408	1,823,889	1,627,038	1,709,695	1,723,583

Nucor Steel	1998	1999	2000	2001	2002	2,003	2004
Jan	176,098	185,686	178,684	33,801	196,813	149,727	220,700
Feb	110,260	166,205	17,279	112,297	158,909	198,904	110,330
Mar	29,578	15,889	166,644	108,440	153,749	193,390	218,414
Apr	170,126	126,770	16,357	195,424	197,884	212,080	188,294
May	166,663	171,070	13,069	110,899	183,753	191,850	201,707
Jun	87,141	181,087	-	180,274	184,808	206,305	123,006
Jul	12,366	4,514	107,970	115,561	26,217	82,900	120,472
Aug	19,224	10,972	16,383	103,073	185,542	211,222	131,382
Sep	96,800	175,529	106,241	170,632	184,826	140,954	212,112
Oct	96,648	168,089	173,548	196,105	146,104	118,510	225,532
Nov	89,738	176,408	184,482	184,811	126,486	216,334	139,188
Dec	160,365	112,531	159,627	158,820	26,731	142,265	132,273
Total	1,215,007	1,494,750	1,140,284	1,670,137	1,771,822	2,064,441	2,023,410

SYSTEM							
Jan	1,437,583	1,728,441	1,613,553	1,452,613	1,804,293	1,889,208	1973146
Feb	1,322,244	1,440,343	1,434,439	1,564,791	1,812,291	1,667,418	1675669
Mar	1,417,902	1,215,034	1,160,674	1,362,543	1,759,471	1,594,414	1532243
Apr	1,160,209	1,203,004	1,131,563	1,440,219	1,374,425	1,517,311	1445540
May	1,584,686	1,350,337	1,561,260	1,571,949	1,524,031	1,706,388	1579873
Jun	1,692,003	1,672,109	1,507,373	1,782,068	1,735,665	1,846,503	1734571
Jul	1,763,514	1,689,392	1,939,282	1,883,846	1,794,224	1,961,088	2050924
Aug	1,631,411	1,760,574	1,937,439	1,888,675	1,949,664	2,072,835	2045937
Sep	1,717,660	1,691,471	1,956,410	1,654,228	1,899,032	1,628,233	1647351
Oct	1,227,271	1,328,922	1,550,264	1,354,136	1,578,030	1,351,964	1572359
Nov	1,181,067	1,376,030	1,602,054	1,554,120	1,515,307	1,615,784	1584192
Dec	1,576,700	1,481,841	1,862,975	1,576,257	1,506,932	1,716,020	1909311
Total	17,712,250	17,937,498	19,257,286	19,085,445	20,253,365	20,567,166	20,751,116

kilowatt-hours

Rate 1	Growth 98-99	Growth 99-00	Growth 00-01	Growth 01-02	Growth 02-03	Growth 03-04
Jan	11.0%	1.2%	16.9%	-5.7%	13.2%	-2.7%
Feb	-0.5%	10.9%	8.9%	5.6%	11.2%	4.6%
Mar	-1.3%	-3.7%	14.1%	7.1%	-3.7%	-4.0%
Apr	4.5%	3.5%	7.0%	6.1%	-0.5%	1.9%
May	-11.1%	12.0%	2.3%	-1.5%	5.1%	8.5%
Jun	-11.0%	0.9%	6.2%	6.8%	-8.9%	9.2%
Jul	0.5%	-0.4%	7.6%	-3.8%	3.4%	-5.9%
Aug	10.1%	12.4%	-7.9%	0.3%	4.6%	-11.4%
Sep	-11.3%	14.8%	-7.6%	14.0%	-11.5%	12.9%
Oct	4.7%	9.5%	-1.8%	6.4%	-1.9%	6.1%
Nov	2.8%	24.0%	-10.4%	13.0%	-2.0%	0.4%
Dec	1.2%	29.3%	-16.7%	8.0%	4.4%	7.6%
Total	-0.3%	9.2%	0.6%	4.0%	1.9%	1.5%
June-Sep	-2.5%	6.6%	-0.6%	3.3%	-2.4%	-0.5%
Dec-Feb	4.0%	13.9%	1.2%	2.2%	9.5%	3.0%
Shoulder Months	-0.6%	8.9%	1.7%	6.1%	1.3%	2.6%

kilowatt-months coincident peak demand

Rate 1	Growth 98-99	Growth 99-00	Growth 00-01	Growth 01-02	Growth 02-03	Growth 03-04
Jan	27.5%	-8.4%	12.1%	2.6%	15.6%	-4.2%
Feb	7.4%	12.5%	1.7%	16.9%	-4.3%	5.3%
Mar	-17.6%	-6.5%	15.1%	37.1%	-14.9%	-12.1%
Apr	9.8%	5.7%	13.5%	0.8%	8.8%	-5.4%
May	-23.9%	34.7%	-5.2%	-2.6%	8.6%	-4.1%
Jun	-11.7%	5.9%	1.1%	2.7%	7.8%	-3.6%
Jul	5.0%	3.8%	-1.2%	-1.9%	4.1%	4.1%
Aug	11.1%	5.5%	-4.9%	0.5%	3.8%	0.8%
Sep	-8.0%	22.9%	-18.6%	17.5%	-16.5%	6.2%
Oct	-2.3%	27.6%	-19.0%	35.3%	-20.7%	10.0%
Nov	10.5%	23.8%	-3.7%	0.7%	6.9%	0.6%
Dec	-5.9%	29.0%	-17.6%	4.2%	7.0%	18.1%
Total	-0.9%	12.0%	-3.6%	8.3%	0.1%	1.2%
June-Sep	-0.8%	9.1%	-6.2%	4.1%	-0.3%	1.8%
Dec-Feb	8.9%	10.0%	-2.4%	7.7%	6.0%	5.8%
Shoulder Months	-7.3%	17.1%	-1.4%	13.2%	-3.4%	-2.6%

Rate 1 Growth 1998-2004

	Peak Growth	Energy Growth
Jan	6.8%	5.3%
Feb	6.4%	6.7%
Mar	-1.5%	1.2%
Apr	5.4%	3.7%
May	-0.3%	2.3%
Jun	0.2%	0.2%
Jul	2.3%	0.1%
Aug	2.7%	1.0%
Sep	-0.7%	1.2%
Oct	3.0%	3.8%
Nov	6.1%	4.1%
Dec	4.7%	4.8%
Total	2.7%	2.8%
June-Sep	1.2%	0.6%
Dec-Feb	5.9%	5.5%
Shoulder Months	2.2%	3.3%

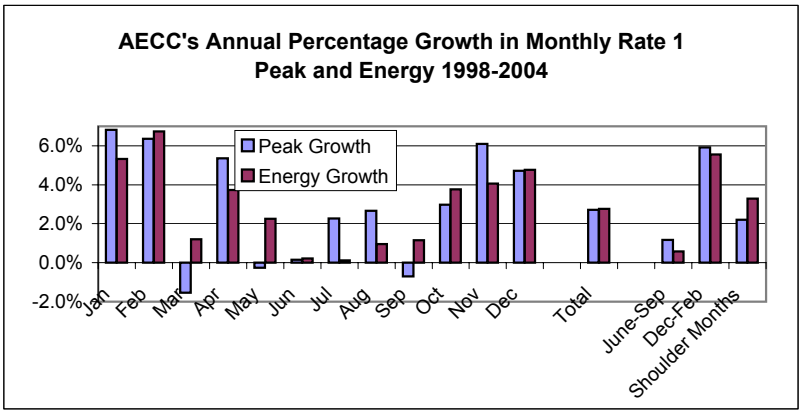


Exhibit WBM-4 **Impact of the Attorney General's Cost Classification and Rate Design on Individual Distribution Co-ops and Interruptible Customers**

Organization of Exhibit WBM-4

The next six pages contain actual coincident demand and billing demand calculations for each co-op.

The remainder of the exhibit contains rate comparisons between the Attorney General's proposed rates and AECC's proposed rates using the billing demand calculations developed on the first six pages.

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	North Ark
2004 Data									
Billing demands (current co-op)	636,183	221,704	869,876	3,316,614	497,596	1,160,365	3,362,020	245,376	1,343,474
Billing demands (AG full implementation)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	292,313	1,478,601
Billing demands (year 1 phase-in 10%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,578,774	269,914	1,474,239
Billing demands (year 2 phase-in 13%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	277,275	1,478,601
Billing demands (year 3 phase-in 16%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	284,636	1,478,601
Billing energy	244,589,238	90,868,148	348,949,006	1,349,190,238	201,283,241	463,964,907	1,327,771,070	227,296,208	575,161,443
Co-op proposed rates									
demand	$ 8.40								
energy	$ 0.02230								
demand	$ 5,343,937	$ 1,862,313	$ 7,306,957	$ 27,859,553	$ 4,179,803	$ 9,747,063	$ 28,240,969	$ 2,061,158	$ 11,285,177
energy	$ 5,454,340	$ 2,026,360	$ 7,781,563	$ 30,086,942	$ 4,488,616	$ 10,346,417	$ 29,609,295	$ 5,068,705	$ 12,826,100
total	$ 10,798,277	$ 3,888,673	$ 15,088,520	$ 57,946,496	$ 8,668,419	$ 20,093,480	$ 57,850,264	$ 7,129,864	$ 24,111,278
AG rates, co-op revenue requirement year 1 phase in				**Current or 110% of old demand billing determinants, whichever is less**					
demand	7.55								
energy	0.02343								
demand	$ 5,091,963	$ 1,672,548	$ 6,788,703	$ 26,318,801	$ 3,679,440	$ 9,082,764	$ 27,019,740	$ 2,037,848	$ 11,130,502
energy	$ 5,730,726	$ 2,129,041	$ 8,175,875	$ 31,611,527	$ 4,716,066	$ 10,870,698	$ 31,109,676	$ 5,325,550	$ 13,476,033
total	$ 10,822,689	$ 3,801,588	$ 14,964,578	$ 57,930,328	$ 8,395,507	$ 19,953,462	$ 58,129,417	$ 7,363,398	$ 24,606,535
increase over co-op rates	0.23%	-2.24%	-0.82%	-0.03%	-3.15%	-0.70%	0.48%	3.28%	2.05%
increase=1, decrease=0	1	0	0	0	0	0	1	1	1
AG rates, co-op revenue requirement year 2 phase in				**Current or 113% of old demand billing determinants, whichever is less**					
demand	7.55								
energy	0.02343								
demand	$ 5,091,963	$ 1,672,548	$ 6,788,703	$ 26,318,801	$ 3,679,440	$ 9,082,764	$ 27,036,709	$ 2,093,425	$ 11,163,439
energy	$ 5,730,726	$ 2,129,041	$ 8,175,875	$ 31,611,527	$ 4,716,066	$ 10,870,698	$ 31,109,676	$ 5,325,550	$ 13,476,033
total	$ 10,822,689	$ 3,801,588	$ 14,964,578	$ 57,930,328	$ 8,395,507	$ 19,953,462	$ 58,146,385	$ 7,418,975	$ 24,639,471
increase over co-op rates	0.23%	-2.24%	-0.82%	-0.03%	-3.15%	-0.70%	0.51%	4.05%	2.19%
increase=1, decrease=0	1	0	0	0	0	0	1	1	1

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	North Ark	Ouachita
Actual Coincident Demands										
Jan-03	55,377	16,641	74,900	281,772	33,000	99,019	316,496	33,359	136,605	42,549
Feb-03	50,270	12,534	60,457	238,140	26,056	77,548	273,978	27,361	121,405	34,346
Mar-03	43,599	11,865	58,352	227,595	25,614	71,052	229,499	27,514	101,895	35,531
Apr-03	38,774	11,453	52,496	194,263	22,975	58,936	195,194	27,523	85,124	35,151
May-03	46,618	16,617	64,712	226,661	26,239	64,393	241,690	26,547	82,552	39,883
Jun-03	51,961	18,175	74,510	270,360	41,828	97,327	276,013	19,744	107,349	46,949
Jul-03	57,398	24,002	81,555	297,462	46,270	110,091	306,974	22,841	126,537	49,962
Aug-03	58,535	20,643	78,472	315,200	46,112	105,433	299,977	22,760	126,187	48,173
Sep-03	45,060	16,933	66,852	218,593	35,998	81,405	238,987	17,141	85,259	43,694
Oct-03	33,261	11,752	51,791	166,177	30,629	62,411	171,411	27,848	64,838	32,082
Nov-03	43,099	12,227	59,871	205,575	27,871	72,007	234,843	32,424	94,008	37,120
Dec-03	47,530	13,007	61,125	251,620	28,550	77,185	246,162	32,280	95,243	40,110
Jan-04	54,987	14,684	68,866	275,465	31,281	91,003	292,641	31,697	130,735	43,373
Feb-04	52,183	14,323	65,221	264,015	25,164	81,141	273,804	32,189	123,868	38,790
Mar-04	36,863	11,073	51,570	194,980	25,130	67,512	207,678	20,112	52,196	34,297
Apr-04	34,983	10,233	46,695	186,176	22,478	59,221	177,685	28,562	83,865	32,549
May-04	41,312	12,779	58,287	225,141	32,628	74,684	215,902	28,911	92,541	39,262
Jun-04	52,666	16,283	64,411	272,214	40,185	86,709	274,862	19,444	110,107	40,244
Jul-04	59,425	20,372	84,207	307,837	46,020	114,429	329,419	22,664	128,809	52,632
Aug-04	59,187	19,912	80,447	311,453	44,314	107,152	313,272	22,821	122,243	49,810
Sep-04	48,279	17,307	72,458	233,257	39,485	90,423	265,477	29,807	89,432	45,938
Oct-04	37,954	11,716	57,159	181,399	25,701	63,820	192,549	32,369	74,942	38,107
Nov-04	44,520	10,233	52,719	233,637	28,336	69,130	217,054	27,182	92,903	34,766
Dec-04	54,576	13,352	72,006	291,099	32,523	101,723	307,083	25,149	125,325	40,706
Current billing demand (minimum of 4 month average or 90% of peak month)										
Jan-04	52,682	18,579	70,625	275,404	41,501	94,890	269,979	20,484	111,333	43,356
Feb-04	52,682	18,579	70,625	275,404	41,501	94,890	269,979	20,484	111,333	43,356
Mar-04	52,682	18,579	70,625	275,404	41,501	94,890	269,979	20,484	111,333	43,356
Apr-04	52,682	18,579	70,625	275,404	41,501	94,890	269,979	20,484	111,333	43,356
May-04	52,682	18,579	70,625	275,404	41,501	94,890	269,979	20,484	111,333	43,356
Jun-04	52,682	18,579	70,625	275,867	41,501	94,890	269,979	20,484	112,023	43,356
Jul-04	52,682	18,558	70,625	278,461	41,501	94,890	269,979	20,484	112,591	43,356
Aug-04	53,483	18,335	73,979	277,053	41,418	97,424	289,135	20,398	111,605	46,595
Sep-04	53,483	18,335	75,381	277,053	41,418	99,678	295,758	20,398	112,648	47,156
Oct-04	53,483	18,335	75,381	277,053	41,418	99,678	295,758	20,398	112,648	47,156
Nov-04	53,483	18,335	75,381	277,053	41,418	99,678	295,758	20,398	112,648	47,156
Dec-04	53,483	18,335	75,381	277,053	41,418	99,678	295,758	20,398	112,648	47,156
TOTAL	636,183	221,704	869,876	3,316,614	497,596	1,160,365	3,362,020	245,376	1,343,474	538,709

	Ozarks	Petit Jean	Rich Mountain	South Central	Southwest Arkansas	Woodruff	Rate 1
Actual Coincident Demands							
Jan-03	147,050	68,216	27,808	49,558	118,116	*67,065*	1,567,531
Feb-03	126,484	58,385	24,870	39,498	104,378	*52,574*	1,328,284
Mar-03	124,482	50,445	21,563	41,199	91,235	*48,962*	1,210,402
Apr-03	111,079	43,632	19,352	37,710	92,636	*44,495*	1,070,793
May-03	148,838	44,241	22,917	40,091	113,084	*61,004*	1,266,087
Jun-03	176,918	51,638	26,435	44,361	119,909	*64,020*	1,487,497
Jul-03	194,798	61,184	28,666	46,676	121,225	*67,982*	1,643,623
Aug-03	205,593	63,464	28,648	45,657	122,872	*65,188*	1,652,914
Sep-03	150,965	46,514	21,978	39,762	106,369	*58,739*	1,274,249
Oct-03	117,608	36,494	15,618	33,036	85,830	*44,881*	985,667
Nov-03	117,899	48,508	22,255	39,907	107,328	*53,024*	1,207,966
Dec-03	137,418	53,744	23,409	41,161	111,070	*54,130*	1,313,744
Jan-04	148,454	62,381	26,262	46,351	122,382	*60,761*	1,539,313
Feb-04	135,801	58,486	26,357	42,998	114,234	*51,797*	1,438,392
Mar-04	112,723	44,838	19,788	36,919	89,724	*48,537*	1,091,990
Apr-04	107,144	40,475	18,427	35,240	86,472	*42,189*	1,050,475
May-04	145,378	41,485	18,777	35,692	100,985	*48,582*	1,250,457
Jun-04	181,905	53,701	23,992	38,114	95,279	*61,359*	1,469,617
Jul-04	206,106	64,022	29,953	46,900	122,096	*73,533*	1,746,596
Aug-04	203,980	61,921	29,791	46,273	122,590	*67,552*	1,700,921
Sep-04	165,763	46,467	23,822	38,973	98,803	*63,582*	1,407,507
Oct-04	127,615	39,852	18,563	35,952	101,667	*44,807*	1,122,436
Nov-04	148,253	46,781	22,054	37,523	101,909	*46,358*	1,251,653
Dec-04	174,808	66,196	26,706	43,092	112,534	*65,680*	1,590,883
Current billing demand (minimum of 4 month average or 90% of peak month)							
Jan-04	182,069	55,700	25,783	41,091	110,585	*58,669*	1,510,718
Feb-04	182,069	55,700	25,783	41,091	110,585	*58,669*	1,510,749
Mar-04	182,069	55,700	25,783	41,091	110,585	*58,669*	1,510,778
Apr-04	182,069	55,700	25,783	41,091	110,585	*58,669*	1,510,809
May-04	182,069	55,700	25,783	41,091	110,585	*58,669*	1,510,839
Jun-04	183,315	56,216	25,783	41,091	110,585	*58,669*	1,513,786
Jul-04	185,034	56,925	25,783	41,091	110,585	*58,669*	1,519,385
Aug-04	185,495	56,540	26,429	42,210	109,886	*65,296*	1,553,482
Sep-04	185,495	56,528	26,890	42,210	109,692	*66,180*	1,566,535
Oct-04	185,495	56,528	26,890	42,210	109,692	*66,180*	1,566,565
Nov-04	185,495	56,528	26,890	42,210	109,692	*66,180*	1,566,596
Dec-04	185,495	56,528	26,890	42,210	109,692	*66,180*	1,566,626
TOTAL	2,206,168	674,292	314,469	498,689	1,322,748	*740,699*	18,406,868

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	North Ark	Ouachita
Proposed Billing Demands based on 4 highest months of total co-op coincident demand in the current and previous 11 months										
Jan-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	24,261	122,702	47,114
Feb-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	24,261	122,702	47,114
Mar-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	24,261	122,702	47,114
Apr-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	24,261	122,702	47,114
May-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	24,261	122,702	47,114
Jun-04	56,119	18,323	71,611	281,714	39,245	95,934	291,492	24,661	122,460	44,526
Jul-04	56,403	17,996	73,989	292,679	40,900	99,394	299,225	24,141	123,960	46,106
Aug-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	24,157	122,974	46,515
Sep-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	24,157	122,974	46,515
Oct-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	24,157	122,974	46,515
Nov-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	24,157	122,974	46,515
Dec-04	57,044	17,080	76,382	296,464	38,535	103,577	310,604	25,583	126,778	46,630
TOTAL	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	292,313	1,478,601	558,892
4 highest month billing demands versus current billing demands										
	106.0%	99.9%	103.4%	105.1%	97.9%	103.7%	106.5%	119.1%	110.1%	103.7%
[THE NEXT 3 CASES REPRESENT A PHASE-IN SCENARIO. NUMBERS IN ***BOLD*** ARE LOWER BECAUSE OF THE PHASE-IN.]										
Billing Demands based on 4 highest months or 110% of previous billing determinants (first year phase in)										
Jan-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**22,532**	**122,466**	47,114
Feb-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**22,532**	**122,466**	47,114
Mar-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**22,532**	**122,466**	47,114
Apr-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**22,532**	**122,466**	47,114
May-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**22,532**	**122,466**	47,114
Jun-04	56,119	18,323	71,611	281,714	39,245	95,934	291,492	**22,532**	**122,460**	44,526
Jul-04	56,403	17,996	73,989	292,679	40,900	99,394	**296,977**	**22,532**	**123,850**	46,106
Aug-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**22,437**	**122,765**	46,515
Sep-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**22,437**	122,974	46,515
Oct-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**22,437**	122,974	46,515
Nov-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**22,437**	122,974	46,515
Dec-04	57,044	17,080	76,382	296,464	38,535	103,577	310,604	**22,437**	**123,913**	46,630
	674,432	221,530	899,166	3,485,934	487,343	1,203,015	**3,578,774**	**269,914**	**1,474,239**	558,892
4 highest month billing demands with 10% phase in cap versus current billing demands										
	106.0%	99.9%	103.4%	105.1%	97.9%	103.7%	106.4%	110.0%	109.7%	103.7%

	Ozarks	Petit Jean	Rich Mountain	South Central	Southwest Arkansas	Woodruff	Rate 1
Proposed Billing Demands based on 4 highest months of total co-op coincident demand in the current and previous 11 months							
Jan-04	181,441	59,667	27,503	45,761	121,597	*64,488*	1,609,329
Feb-04	181,441	59,667	27,503	45,761	121,597	*64,488*	1,609,360
Mar-04	181,441	59,667	27,503	45,761	121,597	*64,488*	1,609,389
Apr-04	181,441	59,667	27,503	45,761	121,597	*64,488*	1,609,420
May-04	181,441	59,667	27,503	45,761	121,597	*64,488*	1,609,450
Jun-04	175,052	59,089	26,307	43,714	112,962	*63,367*	1,564,718
Jul-04	185,515	60,892	27,214	44,256	115,657	*65,210*	1,611,706
Aug-04	185,111	60,506	27,500	44,410	115,587	*65,801*	1,614,188
Sep-04	185,111	60,506	27,500	44,410	115,587	*65,801*	1,614,219
Oct-04	185,111	60,506	27,500	44,410	115,587	*65,801*	1,614,249
Nov-04	185,111	60,506	27,500	44,410	115,587	*65,801*	1,614,280
Dec-04	183,337	63,630	28,178	45,654	119,901	*66,882*	1,644,581
	2,191,553	723,969	329,210	540,067	1,418,852	*781,103*	19,324,890
4 highest month billing demands versus current billing demands							
	99.3%	107.4%	104.7%	108.3%	107.3%	*105.5%*	104.99%
[THE NEXT 3 CASES REPRESENT A PHASE-IN SCENARIO. NUMBERS IN ***BOLD*** ARE LOWER BECAUSE OF THE PHASE-IN.]							
Billing Demands based on 4 highest months or 110% of previous billing determinants (first year phase in)							
Jan-04	181,441	59,667	27,503	**45,200**	121,597	64,488	1,606,805
Feb-04	181,441	59,667	27,503	**45,200**	121,597	64,488	1,606,836
Mar-04	181,441	59,667	27,503	**45,200**	121,597	64,488	1,606,865
Apr-04	181,441	59,667	27,503	**45,200**	121,597	64,488	1,606,896
May-04	181,441	59,667	27,503	**45,200**	121,597	64,488	1,606,926
Jun-04	175,052	59,089	26,307	43,714	112,962	63,367	1,562,589
Jul-04	185,515	60,892	27,214	44,256	115,657	**64,536**	1,607,066
Aug-04	185,111	60,506	27,500	44,410	115,587	65,801	1,612,260
Sep-04	185,111	60,506	27,500	44,410	115,587	65,801	1,612,500
Oct-04	185,111	60,506	27,500	44,410	115,587	65,801	1,612,530
Nov-04	185,111	60,506	27,500	44,410	115,587	65,801	1,612,561
Dec-04	183,337	**62,181**	28,178	45,654	119,901	66,882	1,637,120
	2,191,553	**722,520**	329,210	**537,263**	1,418,852	**780,429**	19,290,952
4 highest month billing demands with 10% phase in cap versus current billing demands							
	99.3%	107.2%	104.7%	107.7%	107.3%	*105.4%*	104.803%

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	North Ark	Ouachita
Billing Demands based on 4 highest months or 113% of previous billing determinants 2nd year phase in)										
Jan-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,147**	122,702	47,114
Feb-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,147**	122,702	47,114
Mar-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,147**	122,702	47,114
Apr-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,147**	122,702	47,114
May-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,147**	122,702	47,114
Jun-04	56,119	18,323	71,611	281,714	39,245	95,934	291,492	**23,147**	122,460	44,526
Jul-04	56,403	17,996	73,989	292,679	40,900	99,394	299,225	**23,147**	123,960	46,106
Aug-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,049**	122,974	46,515
Sep-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,049**	122,974	46,515
Oct-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,049**	122,974	46,515
Nov-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,049**	122,974	46,515
Dec-04	57,044	17,080	76,382	296,464	38,535	103,577	310,604	**23,049**	126,778	46,630
	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	**277,275**	1,478,601	558,892
4 highest month billing demands with 13% phase in cap versus current billing demands										
	106.0%	99.9%	103.4%	105.1%	97.9%	103.7%	106.5%	113.0%	110.1%	103.7%
Billing Demands based on 4 highest months or 116% of previous billing determinants 3rd year phase in)										
Jan-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,761**	122,702	47,114
Feb-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,761**	122,702	47,114
Mar-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,761**	122,702	47,114
Apr-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,761**	122,702	47,114
May-04	55,720	19,376	75,851	289,622	41,373	100,964	293,901	**23,761**	122,702	47,114
Jun-04	56,119	18,323	71,611	281,714	39,245	95,934	291,492	**23,761**	122,460	44,526
Jul-04	56,403	17,996	73,989	292,679	40,900	99,394	299,225	**23,761**	123,960	46,106
Aug-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,661**	122,974	46,515
Sep-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,661**	122,974	46,515
Oct-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,661**	122,974	46,515
Nov-04	56,566	17,813	74,483	291,742	40,450	99,823	302,549	**23,661**	122,974	46,515
Dec-04	57,044	17,080	76,382	296,464	38,535	103,577	310,604	**23,661**	126,778	46,630
	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	**284,636**	1,478,601	558,892
4 highest month billing demands with 16% phase in cap versus current billing demands										
	106.0%	99.9%	103.4%	105.1%	97.9%	103.7%	106.5%	116.0%	110.1%	103.7%

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	*North Ark*
2004 Data									
Billing demands (current co-op)	636,183	221,704	869,876	3,316,614	497,596	1,160,365	3,362,020	245,376	*1,343,474*
Billing demands (AG full implementation)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	292,313	*1,478,601*
Billing demands (year 1 phase-in 10%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,578,774	269,914	*1,474,239*
Billing demands (year 2 phase-in 13%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	277,275	*1,478,601*
Billing demands (year 3 phase-in 16%)	674,432	221,530	899,166	3,485,934	487,343	1,203,015	3,581,021	284,636	*1,478,601*
Billing energy	244,589,238	90,868,148	348,949,006	1,349,190,238	201,283,241	463,964,907	1,327,771,070	227,296,208	*575,161,443*
Co-op proposed rates									
demand	$ 8.40								
energy	$ 0.02230								
demand	$ 5,343,937	$ 1,862,313	$ 7,306,957	$ 27,859,553	$ 4,179,803	$ 9,747,063	$ 28,240,969	$ 2,061,158	*$ 11,285,177*
energy	$ 5,454,340	$ 2,026,360	$ 7,781,563	$ 30,086,942	$ 4,488,616	$ 10,346,417	$ 29,609,295	$ 5,068,705	*$ 12,826,100*
total	$ 10,798,277	$ 3,888,673	$ 15,088,520	$ 57,946,496	$ 8,668,419	$ 20,093,480	$ 57,850,264	$ 7,129,864	*$ 24,111,278*
AG rates, co-op revenue requirement year 1 phase in				**Current or 110% of old demand billing determinants, whichever is less**					
demand	7.55								
energy	0.02343								
demand	$ 5,091,963	$ 1,672,548	$ 6,788,703	$ 26,318,801	$ 3,679,440	$ 9,082,764	$ 27,019,740	$ 2,037,848	*$ 11,130,502*
energy	$ 5,730,726	$ 2,129,041	$ 8,175,875	$ 31,611,527	$ 4,716,066	$ 10,870,698	$ 31,109,676	$ 5,325,550	*$ 13,476,033*
total	$ 10,822,689	$ 3,801,588	$ 14,964,578	$ 57,930,328	$ 8,395,507	$ 19,953,462	$ 58,129,417	$ 7,363,398	*$ 24,606,535*
increase over co-op rates	0.23%	-2.24%	-0.82%	-0.03%	-3.15%	-0.70%	0.48%	3.28%	*2.05%*
increase=1, decrease=0	1	0	0	0	0	0	1	1	*1*
AG rates, co-op revenue requirement year 2 phase in				**Current or 113% of old demand billing determinants, whichever is less**					
demand	7.55								
energy	0.02343								
demand	$ 5,091,963	$ 1,672,548	$ 6,788,703	$ 26,318,801	$ 3,679,440	$ 9,082,764	$ 27,036,709	$ 2,093,425	*$ 11,163,439*
energy	$ 5,730,726	$ 2,129,041	$ 8,175,875	$ 31,611,527	$ 4,716,066	$ 10,870,698	$ 31,109,676	$ 5,325,550	*$ 13,476,033*
total	$ 10,822,689	$ 3,801,588	$ 14,964,578	$ 57,930,328	$ 8,395,507	$ 19,953,462	$ 58,146,385	$ 7,418,975	*$ 24,639,471*
increase over co-op rates	0.23%	-2.24%	-0.82%	-0.03%	-3.15%	-0.70%	0.51%	4.05%	*2.19%*
increase=1, decrease=0	1	0	0	0	0	0	1	1	*1*

	Ouachita	Ozarks	Petit Jean	Rich Mountain	South Central	Southwest Ark	Woodruff	Rate 1 TOTAL
2004 Data								
Billing demands (current co-op)	538,709	2,206,168	674,292	314,469	498,689	1,322,748	740,699	17,948,980
Billing demands (AG full implementation)	558,892	2,191,553	723,969	329,210	540,067	1,418,852	781,103	18,867,002
Billing demands (year 1 phase-in 10%)	558,892	2,191,553	722,520	329,210	537,263	1,418,852	780,429	18,833,064
Billing demands (year 2 phase-in 13%)	558,892	2,191,553	723,969	329,210	540,067	1,418,852	781,103	18,851,963
Billing demands (year 3 phase-in 16%)	558,892	2,191,553	723,969	329,210	540,067	1,418,852	781,103	18,859,325
Billing energy	261,195,738	862,159,335	289,432,007	127,588,025	255,264,202	676,741,471	376,519,276	7,677,973,553
Co-op proposed rates								
demand								
energy								
demand	$ 4,525,155	$ 18,531,815	$ 5,664,049	$ 2,641,539	$ 4,188,988	$ 11,111,083	$ 6,221,871	$ 150,771,432
energy	$ 5,824,665	$ 19,226,153	$ 6,454,334	$ 2,845,213	$ 5,692,392	$ 15,091,335	$ 8,396,380	$ 171,218,810
total	$ 10,349,820	$ 37,757,968	$ 12,118,382	$ 5,486,752	$ 9,881,380	$ 26,202,418	$ 14,618,251	$ 321,990,242
AG rates, co-op revenue requirem								
demand								
energy								
demand	$ 4,219,637	$ 16,546,222	$ 5,455,026	$ 2,485,537	$ 4,056,338	$ 10,712,331	$ 5,892,237	$ 142,189,636
energy	$ 6,119,816	$ 20,200,393	$ 6,781,392	$ 2,989,387	$ 5,980,840	$ 15,856,053	$ 8,821,847	$ 179,894,920
total	$ 10,339,453	$ 36,746,615	$ 12,236,417	$ 5,474,924	$ 10,037,178	$ 26,568,383	$ 14,714,083	$ 322,084,557
increase over co-op rates	-0.10%	-2.68%	0.97%	-0.22%	1.58%	1.40%	0.66%	0.03%
increase=1, decrease=0	0	0	1	0	1	1	1	8
AG rates, co-op revenue requirement yea								
demand								
energy								
demand	$ 4,219,637	$ 16,546,222	$ 5,465,969	$ 2,485,537	$ 4,077,509	$ 10,712,331	$ 5,897,326	$ 142,332,324
energy	$ 6,119,816	$ 20,200,393	$ 6,781,392	$ 2,989,387	$ 5,980,840	$ 15,856,053	$ 8,821,847	$ 179,894,920
total	$ 10,339,453	$ 36,746,615	$ 12,247,361	$ 5,474,924	$ 10,058,349	$ 26,568,383	$ 14,719,173	$ 322,227,244
increase over co-op rates	-0.10%	-2.68%	1.06%	-0.22%	1.79%	1.40%	0.69%	0.07%
increase=1, decrease=0	0	0	1	0	1	1	1	8

	Ark Valley	Ashley Chicot	C&L	Carroll	Clay	Craighead	First Electric	Mississippi	*North Ark*
AG rates, co-op revenue requirement year 3 phase in				**Current or 116% of old demand billing determinants, whichever is less**					
demand	$ 7.55								
energy	$ 0.02343								
demand	$ 5,091,963	$ 1,672,548	$ 6,788,703	$ 26,318,801	$ 3,679,440	$ 9,082,764	$ 27,036,709	$ 2,149,003	*$ 11,163,439*
energy	$ 5,730,726	$ 2,129,041	$ 8,175,875	$ 31,611,527	$ 4,716,066	$ 10,870,698	$ 31,109,676	$ 5,325,550	*$ 13,476,033*
total	$ 10,822,689	$ 3,801,588	$ 14,964,578	$ 57,930,328	$ 8,395,507	$ 19,953,462	$ 58,146,385	$ 7,474,553	*$ 24,639,471*
increase over co-op rates	0.23%	-2.24%	-0.82%	-0.03%	-3.15%	-0.70%	0.51%	4.83%	*2.19%*
increase=1, decrease=0	1	0	0	0	0	0	1	1	*1*
AG rates, co-op revenue requirement complete implementation									
demand	$ 7.37								
energy	$ 0.02326								
demand	$ 4,970,566	$ 1,632,672	$ 6,626,853	$ 25,691,333	$ 3,591,719	$ 8,866,221	$ 26,392,125	$ 2,154,348	*$ 10,897,291*
energy	$ 5,689,146	$ 2,113,593	$ 8,116,554	$ 31,382,165	$ 4,681,848	$ 10,791,824	$ 30,883,955	$ 5,286,910	*$ 13,378,255*
total	$ 10,659,711	$ 3,746,266	$ 14,743,407	$ 57,073,498	$ 8,273,567	$ 19,658,045	$ 57,276,080	$ 7,441,258	*$ 24,275,546*
increase over co-op rates	-1.28%	-3.66%	-2.29%	-1.51%	-4.56%	-2.17%	-0.99%	4.37%	*0.68%*
increase=1, decrease=0	0	0	0	0	0	0	0	1	*1*
AG rates, AG revenue requirement 10% phase-in				**Current or 110% of old demand billing determinants, whichever is less**					
demand	$ 7.37								
energy	$ 0.02326								
demand	$ 4,970,566	$ 1,632,672	$ 6,626,853	$ 25,691,333	$ 3,591,719	$ 8,866,221	$ 26,375,561	$ 1,989,263	*$ 10,865,139*
energy	$ 5,689,146	$ 2,113,593	$ 8,116,554	$ 31,382,165	$ 4,681,848	$ 10,791,824	$ 30,883,955	$ 5,286,910	*$ 13,378,255*
total	$ 10,659,711	$ 3,746,266	$ 14,743,407	$ 57,073,498	$ 8,273,567	$ 19,658,045	$ 57,259,516	$ 7,276,173	*$ 24,243,394*
increase over co-op rates	-1.28%	-3.66%	-2.29%	-1.51%	-4.56%	-2.17%	-1.02%	2.05%	*0.55%*
increase=1, decrease=0	0	0	0	0	0	0	0	1	*1*

	Ouachita	Ozarks	Petit Jean	Rich Mountain	South Central	Southwest Ark	Woodruff	Rate 1 TOTAL
AG rates, co-op revenue requirement yea								
demand								
energy								
demand	$ 4,219,637	$ 16,546,222	$ 5,465,969	$ 2,485,537	$ 4,077,509	$ 10,712,331	$ 5,897,326	$ 142,387,901
energy	$ 6,119,816	$ 20,200,393	$ 6,781,392	$ 2,989,387	$ 5,980,840	$ 15,856,053	$ 8,821,847	$ 179,894,920
total	$ 10,339,453	$ 36,746,615	$ 12,247,361	$ 5,474,924	$ 10,058,349	$ 26,568,383	$ 14,719,173	$ 322,282,822
increase over co-op rates	-0.10%	-2.68%	1.06%	-0.22%	1.79%	1.40%	0.69%	0.09%
increase=1, decrease=0	0	0	1	0	1	1	1	8
AG rates, co-op revenue requirem								
demand								
energy								
demand	$ 4,119,036	$ 16,151,743	$ 5,335,655	$ 2,426,279	$ 3,980,297	$ 10,456,937	$ 5,756,728	$ 139,049,802
energy	$ 6,075,413	$ 20,053,826	$ 6,732,188	$ 2,967,697	$ 5,937,445	$ 15,741,007	$ 8,757,838	$ 178,589,665
total	$ 10,194,449	$ 36,205,569	$ 12,067,843	$ 5,393,976	$ 9,917,742	$ 26,197,944	$ 14,514,566	$ 317,639,467
increase over co-op rates	-1.50%	-4.11%	-0.4170%	-1.69%	0.37%	-0.02%	-0.71%	-1.35%
increase=1, decrease=0	0	0	0	0	1	0	0	3
AG rates, AG revenue requirement 10% pl								
demand								
energy								
demand	$ 4,119,036	$ 16,151,743	$ 5,324,972	$ 2,426,279	$ 3,959,631	$ 10,456,937	$ 5,751,760	$ 138,799,685
energy	$ 6,075,413	$ 20,053,826	$ 6,732,188	$ 2,967,697	$ 5,937,445	$ 15,741,007	$ 8,757,838	$ 178,589,665
total	$ 10,194,449	$ 36,205,569	$ 12,057,160	$ 5,393,976	$ 9,897,076	$ 26,197,944	$ 14,509,598	$ 317,389,349
increase over co-op rates	-1.50%	-4.11%	-0.51%	-1.69%	0.16%	-0.02%	-0.74%	-1.43%
increase=1, decrease=0	0	0	0	0	1	0	0	3

Exhibit WBM-5 Distribution Co-op Web Pages Promoting Heat Pumps

Main Office
P.O. Box 1619
3190 N. Washington
Forrest City, AR
72336-1619

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Forrest City, AR

Comparing Heating Costs

When comparing heating costs, you have to compare "apples to apples."

How do you compare the actual cost of heat produced by the different types of heating systems?

Electricity is sold in kilowatt-hours. Propane is sold in gallons. Natural gas is sold in units of hundred-cubic-feet.

How do you compare the cost to heat?

In order to make this comparison, you must first bring all the fuel types and types of heating systems to a common unit. That unit is British Thermal Units.

Before we get started, you need to know that Woodruff Electric's rates are structured by considering many factors. Those factors include the price paid by Woodruff Electric for wholesale electricity. The wholesale electricity charge is based on how much electricity is used and when it is used. It is also based on how much it costs to generate that electricity.

What you may not know is that most of the electricity you use as a Woodruff Electric member is generated with coal. After coal, approximately 10% is generated with hydroelectric energy. Because the fuel prices for coal and water vary only slightly, your electricity prices have remained very stable, even during times of increasing natural gas prices and volatile oil prices.

Please study Woodruff Electric's residential electric rate to see what a great deal electricity is for winter heating. In winter, every house will have an electric bill, but only those homes with gas heat will have a gas bill. The cheap electricity starts after 500 kilowatt-hours each month, and almost every home will use at least 500, no matter what fuel is used for heating.

You do the math:

$$\frac{\text{100,000 BTUs}}{\text{BTUs per unit of fuel}} \div \text{efficiency of system} \times \text{cost per unit of fuel} = \text{cost per 100,000 BTUs}$$

Heating System	System Efficiency	Fuel Cost	Energy (BTUs) per unit of fuel	Cost of 100,000 BTU's of Heat

site developed and maintained by INTERWERK

Electric Resistance	100%	$.04/KWH	3,413 BTU/KWH	$1.17
Propane	80%	$1.20/gal	91,600 BTU/gal	$1.64
Natural Gas	80%	$.74/100 cu. ft.	100,000 BTU /100 cu. ft.	$.92
Elec. Heat Pump	220%	$.04/KWH	3,413 BTU/KWH	$.53
Geothermal Elec. Heat Pump	400%	$.04/KWH	3,413 BTU/KWH	$.29

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Carroll Electric
COOPERATIVE CORPORATION
Your Local Energy Partner

Powering Northwest Arkansas and Southwest Missouri since 1937

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HEAT PUMP FINANCING

Low-interest financing available
to qualifying customers for
high-efficiency heat pumps

- 0% down
- 5% annual percentage rate
- 84-months to pay


Heat your home
in the winter


Cool it
in the summer


Save
all year round

If you're thinking of making some improvements, keep in mind a high-efficiency electric heat pump will keep your home comfortable year round. And, low-interest financing will keep your budget comfortable, too. Carroll Electric may be able to assist you with financing of a heat pump system in your existing home. Five-percent interest loans are available to qualifying customers of the cooperative. If you are interested in finding out more about this low-interest financing program, please call the cooperative's member services department. We'll be glad to answer your questions.

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info@carrollecc.com

1-800-432-9720

ZARKS
ELECTRIC COOPERATIVE CORPORATION
3641 Wedington Dr.
P.O. Box 848
Fayetteville, AR 72702
A Touchstone Energy® Cooperative · (800) 521-6144 ·

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ENERGY EFFICIENT LOAN REQUIREMENTS

Click here for the Ozarks Electric Credit Application.

1. **Applicant must be a member of Ozarks Electric Cooperative Corporation.**
2. **Structure must pass inspection by qualified Ozarks Electric employee.**
3. **Ozarks Electric will finance the installation of heat pumps and related material that meet the following criteria:**

   A) Heat Pumps

      1. Must be new
      2. Must have an HSPF rating of 7.0 or more
      3. Must have a SEER rating of 12.0 or more
      4. Along with electrical upgrade must constitute at least 50% of total amount of loan request

   B) Weatherization Material

      1. Insulation

         Walls: R-13
         Ceilings: R-38
         Floors (crawl space): R-19

      2. Storm windows or replacement windows with double glass
      3. Storm doors or metal insulated door with weatherstripping
      4. Must be well-sealed, insulated metal duct
      5. **NO FLEX DUCT!**

4. **The member's credit must meet the following criteria.**

   A) Receive a satisfactory report from local credit bureau

   B) Have no more than 2 late payments on electric bills to Ozarks Electric within the last 12 months

5. **Details of Loan:**

- The maximum amount of any loan will be $5,000 unless approved by the Board of Directors
- A 3-person committee composed of any one board member and two employees will approve loan amounts up to $5,000.
- Loans are available on existing structures only.

- A lien will be filed on the equipment and related weatherization materials.
- The loans will be for a maximum period of 7 years.
- Loans will not be processed without signed contracts between homeowner and any contractors submitting bids for loan approval.

6. **The member must be gainfully employed or have other source(s) of sufficient income.**
7. **All applicable filing fees shall be at the borrower's expense.**

Email us for more information.

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1-800-489-7405

Home Improvement Loans

Energy Efficiency Loans For Your Home

With First Electric Cooperative's Home Improvement Loan Program, you don't to put off upgrading the energy efficiency of your home any longer. The Home Improvement Loan program will allow you to finance the following energy sav items at a competitive, fixed interest rate:

- **Heat pumps** - and related improvements associated with heat pump installation
  - Duct systems
  - Duct Sealing
  - Thermal improvements - insulation, caulking and ventilation
  - Windows and doors
  - Electric service upgrades
- **First Electric Products** - purchases under $500 may be applied to y electric bill and paid in 3 monthly installments
  - Marathon electric water heaters
  - Surge and lightning protection equipment
- **Portable home generators**

First Electric's Home Improvement Loans have many attractive feature

- Borrow as little as $500 or as much as $15,000
- Terms from 12 to 60 months
- Fixed interest rate for the life of the loan
- No pre-payment penalty
- Payments included on monthly electric bill

Other Loan terms and features

- Borrower must own and occupy the property and demonstrate adequa credit history
- Eligible property includes only single-family dwellings that are primary secondary residences and are served electric power by FECC
- Loans between $500 and $2500 secured with an equipment lien
- Loans over $2500 secured with a property mortgage and equipment li
- $35.00 filling fee for loans over $2500

For more information or to apply for First Electric Cooperative's Home Improvement Loan Program, contact your local First Electric office at (800)-48

Home Improvment Loans

7405 and ask for a Member Services Representative or click here. We have provided an online application that you can print, fill-out, and mail in. You mu have Adobe Acrobat to view and print the application. If you dont have Adobe Acrobat simply click here.

Click here to print application

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Southwest Arkansas Electric Cooperative

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Automated Response Center
1-888-265-2743 (Toll Free)

General Office
Response Center
1-800-782-2743 (Toll Free)

Texarkana Office
2904 E. 9th St.
Texarkana, AR 71854
(870) 772-2743

Bradley Office
Highway 29
Bradley, AR 71826
(870) 894-3329

DeQueen Office
110 Crosstrail Rd.
DeQueen, AR 71832
(870) 642-2737

Nashville Office
1665 So. 4th St.
Nashville, AR 71852
(870) 845-1313

5% ERC LOAN PROGRAM

Southwest Arkansas Electric REA's Energy Resources Conservation (ERC) Loan Program provides low cost financing for high efficiency hear pumps and other energy conservation improvements needed to make your home energy efficient.

With approved credit and completion of the home survey, REA will loan up to $5,000 per member per residential structure at 5% interest for up to 84 months. These loans are to finance energy conservation measures including heat pumps (including water source), caulking, weather stripping, insulation, storm or thermal doors and windows, etc. Loans for more than $5,000 will need Board of Director approval. Loans, which do not include a heat pump, will be limited to $3,000.

To qualify all conservation measures must save enough energy within 10 years to pay for the improvements. The Cooperative's Home Survey determines payback estimates. Because loan funds are limited, loans will be made on a first come, first served basis.

QUALIFICATIONS
To qualify for the loan you must have a good credit history with Southwest Arkansas Electric Cooperative and a good national credit rating. A three-member loan committee will check the member's credit before approving the loan. Loans will only be made for existing homes or buildings. The program is not for homes under construction. Also you must own the property being improved.

The cooling capacity of the heat pump should not exceed 125% of the calculated design load. The heat pump must also meet minimum efficiency ratings to qualify. The SEER rating must be 12.0 or above and the HSPF must be 7.0 or higher. For package systems the SEER rating must be at least 9.5 and the HSPF must be at least 6.60. All duct work, including all supply and return air duct work, must be installed with a minimum of 2" duct insulation or rigid fiberglass board and must be sized properly for noise reduction and air flow.

HOME SURVEY
Before a loan can be made, a home energy survey must be completed. This is a questionnaire concerning your existing and proposed energy efficiency.

CONTACT YOUR DEALER
We advise, but do not require, you to contact more than one qualified dealer or contractor for cost estimates to install a heat pump and making other improvements such as storm windows or insulation if they are advised. **To qualify for the ERC Loan, a member of the Arkansas HVACR Association must install the unit.**

SUBMIT APPLICATION FOR ERC LOAN
Your application will be submitted to our load committee for consideration and we will notify you in writing of their decision. Once your credit is approved we will need a copy of your property deed. A copy of your deed is required for proof of ownership and a legal description. To secure the load a lien will be filed on the improvements financed.

PROCESSING LOAN DOCUMENTS
After the work is completed, please schedule a final inspection of the work with our office. If you have not already done so at that time, please furnish a copy of your deed

and any bills or receipts so that loan papers can be completed for your signature. Once the loan papers are completed we will make an appointment with you to come to our Texarkana office to sign the loan papers and have them notarized. All checks will be two party checks made out to both you and the contractor or contractors.

Note: Cost of equipment and installation are to be negotiated between you and your contractor. You will be responsible for getting the invoices to us for processing and for making payment to your contractor. A two party check will be written to both you and the dealer. Sign the check only after work is completed.

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