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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	CASE NO. AVU-E-04-01
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	
AND NATURAL GAS CUSTOMER IN	)	
THE STATE OF IDAHO	)	

COEUR SILVER VALLEY

REBUTTAL TESTIMONY OF

ANTHONY J. YANKEL

July 12, 2004

Q. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My address is 29814 Lake Road, Bay Village, Ohio, 44140.

Q. ARE YOU THE SAME ANTHONY J. YANKEL THAT HAS PROVIDED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I address certain issues brought up by the Staff with respect to Schedule 25.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO THE ASSIGNMENT OF COSTS TO SCHEDULE 25 CUSTOMERS AS WELL AS THE RATE DESIGN FOR THAT CUSTOMER CLASS.

A. The Staff's cost-of-service study (like the Company's) fails to properly address the assignment/allocation of certain primary distribution related costs to Schedule 25. If data is utilized that is more reflective of cost causation, the rate of return for Schedule 25 comes out to be above the jurisdictional average.

Although the Staff's rate design is somewhat of an improvement over that proposed by the Company with respect to recognizing the benefits of load factor for Schedule 25 customers, there is still a good deal of room for improvement. I develop a rate design for Schedule 25 customers that is similar to that recently approved on the Idaho Power system, which far better reflects a rate differential between high and low load factor customers.

COST-OF-SERVICE STUDY

Q. DO YOU AGREE WITH THE STAFF'S COST-OF-SERVICE ANALYSIS?

A. No. The cost-of service study used by the Staff is simply the Company's cost study with the inclusion of the Staff's (as opposed to the Company's) revenue requirement numbers. Basically, the Staff did not challenge any of the Company's methodology. Admittedly, I did not challenge a great deal of the study either, but my review was limited to only one group of 14 customers with very specific characteristics.

In 1994, the summer peak was only 88% of the winter peak[1] while in the 2002 test year data used in this case, the summer peak is approximately 4% higher than the winter peak[2]. Primarily, this change has been brought about by an increase in air-conditioning load, which has prompted the Company to begin including cooling degree values in its load normalization calculations. It is my understanding that the load research data used in this case was gathered over 10 years ago, during a time when this system was winter peaking. I mention this because the Company's load research data impacts the residential class[3]. The Company's cost-of-service study lists the Residential class (like Schedule 25) as being significantly below cost-of-service. A lot of the disparity that the Company's cost-of-service study is showing for the Residential class could simply be an artifact of the outdated data being used by the Company that reflects a very different load profile. Like Schedule 25, a lot more review should go into the data used to develop cost-of-service studies before they are used to disproportionately raise rates for any one class of customers.

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[1] July 1994 peak was 1,270 MW while the December peak was 1,436 MW.
[2] Page TLK-78 of the workpapers provided by Tara L. Knox.
[3] It does not impact the cost-of-service for Schedule 25 as they are all measured hourly.

Q. HAS THE STAFF DISAGREED WITH YOUR POSITION WITH RESPECT TO DEVELOPING MORE OF A DIRECT ASSIGNMENT FOR CERTAIN DISTRIBUTION COSTS TO THE SCHEDULE 25 CUSTOMERS?

A. No, I assume that the lack of inclusion of direct assignment data for these distribution costs associated with Schedule 25 was more of an oversight or lack of data, than a deliberate disagreement with the treatment. Most rate analysts would agree that it is far more appropriate/accurate to directly assign costs than it is to allocate costs.

Q. CAN DISTORTIONS IN COST-OF-SERVICE RESULT IF DIRECT ASSIGNMENTS ARE NOT MADE?

A. Yes, significant distortions can occur if direct assignments are not made. Potlatch-Lewiston is a good example. This is by far the largest customer on the system and is three times the size of all Schedule 25 customers combined. The Company either allocates distribution plant on the basis of Non-Coincident Peak (NCP) or it is directly assigned. Potlatch-Lewiston's share of the Idaho NCP is 20%[4]. Potlatch-Lewiston is directly assigned only $70,921 of Account 361 costs (Structures and Improvements), but if these costs were to be simply allocated on the basis of NCP, Potlatch-Lewiston would be allocated $519,883[5] or over 7-times the actual cost incurred. Potlatch-Lewiston does not even use any Account 364 (Poles, Towers & Fixtures), but

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[4] Exhibit 16 Schedule 2 page 31 line21.
[5] $2,627,000 times 19.79% equals $519,883.

an allocation based upon NCP would place a burden upon this facility of $11,283,269[6]. Simply put, it is inappropriate to allocate costs to large customers on the basis of NCP when it is possible to directly assign or more accurately define cost causation.

Q. IS THE DATA YOU USED TO ASSIGN/ALLOCATE COSTS TO SCHEUDLE 25 A TRUE DIRECT ASSIGNMENT?

A. No. A true direct assignment would assign only costs. As a surrogate for cost causation, I chose to use the actual miles of primary distribution line used to serve these customers and the assumption that costs per circuit mile average out to be the same. If the Company can produce actual cost figures for the 21 miles of the primary distribution lines that is used to serve all Schedule 25 customers[7] (compared to 3,857 total primary miles in Idaho), then this data should be substituted.

There should be no question that using actual miles of primary distribution line is far more accurate for this customer group than the simple choice of using NCP data to allocate these costs. The NCP data would suggest that an average of 60 miles of primary distribution line was associated with <u>each</u> of the Schedule 25 customers (including Potlatch-Lewiston) when in fact, there is only 21 miles of primary distribution (overhead plus underground) that is used to serve all Schedule 25 customers (including Potlatch-Lewiston).

Q. SHOULD SCHEDULE 25 BE SINGLED OUT TO GET MORE THAN THE AVERAGE RATE INCREASE?

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[6] $57,015,000 times 19.79% equals $11,283,269.
[7] See Exhibit 306.

A. No. The difference in the choice of reflecting the relative number of miles of primary circuits compared to the simplistic application of NCP is the sole difference that pegs the rate of return for Schedule 25 at significantly below average cost-of-service, versus slightly above average cost-of-service. It is this difference that should have been recognized in the Company's cost study, before recommendations were made to disproportionately increase rates for Schedule 25. A fluke in the cost-of-service study or the lack of quality data should not be the cause of a disproportionate increase to any class—especially, when better data is available.

RATE DESIGN

Q. DO YOU AGREE WITH THE STAFF'S OVERALL POSITION WITH RESPECT TO RATE DESIGN FOR SCHEDULE 25?

A. I have some concerns with some of the comments made by the Staff regarding the rate design for Schedule 25 customers. Specifically, I disagree with Mr. Schunke's proposal for the next case to gather additional information so that the Company can provide "a proposal to eliminate the declining block rates in Schedules 21 and 25"[8]. Although I welcome the development of additional data, I do not believe that its intended purpose should be the "elimination of the declining block rates". The data should be allowed to speak for itself and if the data suggests that there should be more declining blocks or steeper declining blocks, then so be it.

Q. DO YOU AGREE WITH THE RATE DESIGN DEVELOPED BY THE STAFF FOR SCHEDULE 25?

A. No. At the outset, I should say that I agree with Dr. Peseau's assessment that Potlatch-Lewiston should not be included in the Schedule 25 rates. This facility should be treated separately as there are no other customers that have load characteristics that are remotely similar. My comments will address rate design for only 14 customers—all but the Potlatch-Lewiston load.

[8] Schunke's direct testimony at page 4 lines 13 and 14.

My primary disagreement with the Staff's proposed rate design for Schedule 25 is that in spite of the inclusion of a declining block energy rate, it still places very little reward (via lower rates) for higher load factor usage. In my direct testimony, I attempted to address this concern in a general way. Now that a more probable revenue requirement is being addressed, it is possible to put a numerical value to the rate design concepts I proposed in order to provide some reward to higher load factor customers.

Q. HOW WOULD YOU DEVELOP A RATE DESIGN FOR SCHEDULE 25 THAT BETTER REWARDS HIGH LOAD FACTOR CUSTOMERS?

A. In my direct testimony, I proposed a ratio between demand costs and tail block energy costs of at least 120:1 in order to be somewhat consistent with the rate design for similar customers in the Idaho Power service area as recently adopted by this Commission. As you may recall, I calculated a ratio of 78:1 for the existing Schedule 25 rates and a ratio of 80:1 for the Company proposed Schedule 25 rates. The Staff proposal of a second demand block rate of $2.75 per kW and 3.268 cents per kWh for the tail block energy rate produces a ratio of 84:1—some improvement, but still a far cry from the rate design on the Idaho Power system.

Instead of the Staff's proposal of $9,000 for the first 3,000 kW and $2.75 per kW for each additional kW, I propose that the initial 3,000 kW be priced at $10,500 and that each additional kW be priced at $3.25 per kW. This demand charge is still less than half of the demand cost calculated by the Company of $7.02 per kW per month for Schedule 25 customers and it serves several purposes: 1) It is a rate that is similar[9] to the rate being charged to Idaho Power Schedule

[9] Idaho Power's Schedule 19 rate has a $3.21 demand charge in the summer and a $2.64 demand charge in the winter, but additionally has a Basic Load Capacity charge of an additional $0.37 per kW of annual peak

19 customers of $3.21 per kW; 2) It places more charges on the demand component so that higher load factor customers will receive more of a benefit; and 3) It allows a ratio of the demand charge to the tail block energy rate to be sufficiently larger without forcing the tail block energy rate itself to be significantly reduced. The net impact of this rate design would be to place approximately half of the increase upon the demand component.

The Staff's tail block energy rate is 3.268 cents per kWh. Using the ratio I previously recommended between demand and tail block energy rates of 120, my proposed tail block energy rate becomes 2.710 cents per kWh. Although there is not a huge difference between these two tail block rates, there is sufficient difference to cause the ratio of demand to energy charges (120) to be similar to the emphasis that is placed upon load factor in the Idaho Power system. This proposed tail block rate is about 6%[10] below the current energy rate for Schedule 25—meaning that the tail block rate would have a slight decrease. If desired, a higher tail block could be developed, but in order to maintain the ratio of demand to tail block energy rate of 120, this would entail raising the demand charge further. It cannot be forgotten that all customers will pay the demand rate as well as the initial and tail block energy rate, so just because one proportion of the rate is going down, it does not mean that the overall bill is being reduced—just the price signals will be arranged differently.

The last rate component to be addressed is the initial energy block. The last rate component must do two things: 1) it must make sense; and 2) it must result in a rate such that when taken in total, all of the rate components produce the revenue requirement for the schedule. I have targeted the average rate increase calculated by the Staff of 15.78% because I believe that

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demand that that effectively increases both the demand an winter demand charges by more than $0.37 per monthly billing demand—depending upon the difference between the monthly billing demand and annual peak demand.

[10] 2.710 cents divided by 2.874 cents equals 94.3%.

Schedule 25 should get no more than the average rate increase. In order to get this percentage increase from Schedule 25 with the above proposed rate components, an initial energy block rate of 4.33 cents per kWh is required. This rate is well within the realm of reason and is 12% greater than the initial block rate proposed by the Staff.

Q. PLEASE SUMMARIZE YOUR RATE DESIGN FOR SCHEDULE 25 AND WHY YOU BELIEVE THAT IT IS BETTER THAN THAT PROPOSED BY EITHER THE COMPANY OR THE STAFF.

A. There is hardly any reward under the present Schedule 25 rate design for high load factor customers. The days of the energy constrained utility in Idaho are numbered. More emphasis should be placed upon demand charges in the Avista service territory compared to the past. I believe that Idaho Power's new rates can serve as a model for rate design in the Avista service area. The demand charge that I have proposed is essentially the same as that for Idaho Power's Schedule 19 and the tail block energy rate is designed to hit a target ratio that is representative of rate design on the Idaho Power system. In some respects, the proposal I am making may seem radical, but the perceived change is more a result of where we have been as opposed to where we should be going—the historical rate design was greatly lacking in its ability to reward high load factor customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

EXHIBIT 306

CONFIDENTIAL

COMPARISON OF PROPOSED RATES FOR SCHEDULE 25

	Billing Determinants	Present Rates	Present Revenue	Staff Proposed Rates	Staff Proposed Revenue	Coeur Proposed Rates	Coeur Proposed Revenue
Bills 3,000 or less kW	168	$7,500	$1,260,000	$9,000	$1,512,000	$10,500	$1,764,000
Greater than 3,000 kW	285,493	$2.25	$642,359	$2.75	$785,106	$3.25	$927,852
Block 1 per kWh	84,000,000	$0.02874	$2,414,160	$0.03873	$3,253,320	$0.04330	$3,637,200
Block 2 per kWh	219,707,481	$0.02874	$6,314,393	$0.03268	$7,180,040	$0.02710	$5,954,073
Primary Voltage Discount			-$155,810		-$155,810		-$155,810
			$10,475,102		$12,574,656		$12,127,315
				Percentage Increase	20.04%		15.77%

Exhibit 307

Certificate of Service

I HEREBY CERTIFY that on this 9th day of July 2004, I caused to be served a true and correct copy of the foregoing document to the individual addressed below:

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