BEFORE THE WASHINGTON UTILITIES
AND
TRANSPORTATION COMMISSION

DOCKET NO. UE-010395
AVISTA CORPORATION

DIRECT TESTIMONY
OF
DONALD W. SCHOENBECK

ON BEHALF
OF
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

AUGUST 24, 2001

Prepared Direct Testimony of Donald W. Schoenbeck
August 24, 2001

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Exhibits

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 1000, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved in the electric and gas utility industries for over 25 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters before numerous state commissions, public utility governing boards, governmental agencies, state and federal courts, the National Energy Board of Canada and the Federal Energy Regulatory Commission ("FERC"). I have appeared before the Washington Utilities and Transportation Commission ("WUTC" or "Commission") at least 20 times since 1982. A further description of my educational background and work experiences is summarized in Exhibit DWS-2.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Avista Utilities ("the Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As noted in the accompanying testimony of ICNU witness Mr. John Thornton and the ICNU legal brief, it is ICNU's position that Avista's request for a surcharge is unjustified and should be denied. However, should the Commission decide a surcharge is warranted, ICNU requested that I determine the maximum level of rate surcharge that the

Commission should impose.

Q. PLEASE BRIEFLY SUMMARIZE AVISTA'S PROPOSED SURCHARGE.

A. The Company's filing proposes a temporary rate surcharge of 36.9% (subject to refund) to be in place for a 27 month period. This level of increase would collect $87.4 million *per year* from the Company's ratepayers. In addition, the Company is proposing an accelerated amortization of the Portland General Electric ("PGE") monetization balance over the 15 month period of October 2001 through December 2002. Taken together, these two mechanisms will offset $245.9 million of the Company's cost deferrals through December 2003. It is important to note that substantial sums associated with the Company's projected deferral balances are associated with new generating assets and speculative forecasts of future events. So, in essence, the Company is seeking recovery of resources yet to be put into service and short-term power costs that would not be reflected in traditional normalized ratemaking.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. My testimony recommends that if the Commission grants interim rate relief, it should be based upon the actual power cost deferrals the Company has experienced for the period from July 2000 through June 2001, adjusted for the normal level of risk borne by the Company as part of the rate normalization process. Further, the accelerated amortization of the PGE deferral should be used first to offset a portion of the deferred costs. To the extent the Commission believes additional relief is needed, this can be accomplished through a limited rate surcharge. Of course, at a latter date—such as the next general rate case—the Company must prove that its deferred power costs were prudent and that recovery of such cost through deferral is appropriate.

Based upon the analysis I have performed, I recommend the maximum temporary surcharge should be no greater than 11.9% imposed for a period not to exceed 15 months (October 2001 through December 2002). This level of surcharge would increase Company revenues by about $28.3 million per year. Taken together, this "two step" approach of using an accelerated amortization of the PGE monies coupled with the rate surcharge would offset $91.0 million of deferred cost over the 15 month period.

PROCEDURAL HISTORY

Q. PLEASE BRIEFLY EXPLAIN THE EVENTS THAT HAVE LED TO THE COMPANY FILING THIS APPLICATION BEFORE THE COMMISSION.

A. On June 22, 2000, the Company filed an application with the Commission seeking the ability to defer power supply-related costs due to the unprecedented level of wholesale market prices. Re Avista Corp., WUTC Docket No. UE-000972, Petition of Avista Corporation (June 22, 2000). The Commission granted the Company the ability to defer costs for the one year period of July 1, 2000 through June 30, 2001, subject to several conditions and requirements. Among the conditions was that the Company would not be able to recover the deferred amounts " . . . until the showing of prudence, including a demonstration that Company-owned resources were optimized to the benefit of retail ratepayers." *See* Re Avista Corp., WUTC Docket No. UE-000972, Order Granting Deferral of Power Cost Expenses Pending Demonstration of Prudence (Aug. 9, 2000). On December 21, 2000, the Company filed with the Commission a request to modify the deferral mechanism to take into account changes in retail load levels and the manner in which the monthly deferral was calculated. The Commission accepted the proposal effective December 2000, subject to the Company filing to review the prudency of the power costs and other matters by March 20, 2001. *See* Re Avista Corp., WUTC Docket

No. UE-000972 Order Granting Request to Modify Power Cost Deferral Mechanism (Jan. 24, 2001).

Pursuant to the Commission order, the Company made the required filing in March. This filing was docketed as UE-010395. Shortly thereafter, the Company proposed a creative solution of using surplus power sale revenue to offset the deferred balance without a change in retail rates. This proposal was incorporated into a Settlement Stipulation ("Stipulation") entered into on April 26, 2001. This Stipulation was filed with the Commission on May 2, 2001, and was approved by the Commission on May 23, 2001. <u>In re Avista Corp.</u>, WUTC Docket No. UE-010395, First Supp. Order Approving and Adopting Settlement Stipulation (May 23, 2001). In accepting the Stipulation, the Commission extended the deferral mechanism through February 28, 2003, or until the deferral balance became zero. The Stipulation allows the Company "to alter, amend or terminate" the Stipulation "should the deferral balance increase or be reasonably anticipated to increase substantially due to unanticipated or uncontrollable events…." Stipulation at ¶4.

<u>IMMEDIATE COMPANY REQUEST</u>

Q. WHAT IS THE COMPANY SEEKING IN ITS JULY 17, 2001 FILING IN THIS DOCKET?

A. In its July 17, 2001 filing, the Company alleges that due to changes in hydroelectric generation conditions and wholesale market prices since the Commission's adoption of the Stipulation, the projected deferral balances will continue to accumulate. In other words, the Company now projects that the wholesale market sale opportunities are inadequate to offset the deferred balance it projects it will have in Washington. The Company's projection indicates a deferred balance of over $217 million (excluding interest) by the end of 2003. Consequently, the Company now seeks immediate implementation of a proposal to recover the deferred balance, including the projected costs through December 2003.

The Company's proposal to recover the anticipated deferred generation-related costs consists of two steps. First, the Company proposes to reduce the remaining PGE monetization amortization period from 27 months (October 2001 to December 2003), to 15 months (October 2001 to December 2002). This would reduce the deferred balance by $53.8 million. Second, the Company proposes to implement a rate surcharge of 36.9%, subject to refund, to recover the remaining deferred balance. This substantial surcharge would raise customer rates by $87.4 million per year. Based upon the Company's projections of going forward hydro conditions, generating unit availability, fuel costs, purchase power costs and wholesale market prices, the deferred balance would be reduced to zero by December 2003. In total, these two devices will provide the Company with $245.9 million over the period of October 2001 through December 2003.

Q. IF THE COMMISSION ALLOWS A SURCHARGE TO BE PUT IN PLACE, SHOULD IT BE SUBJECT TO REFUND?

A. Absolutely. While the Company has acknowledged the monies recovered from ratepayers through the surcharge would be subject to refund due to the numerous projections upon which the deferral forecast was compiled, there is another important point to be made. Very simply, under the accelerated hearing schedule adopted by the Commission for consideration of the Company's proposal, there was no time to conduct a prudence review of the Company's actual or historical deferred balance as of June 2001. Further, over 50% of the projected deferred balance has to do with the recovery of costs—both fixed and variable—related to new generating resources such as Coyote

Springs II. It is impossible to determine in such an abbreviated time period if the Company's actions and decisions to acquire these resources were appropriate. Therefore, should the Commission implement a surcharge, it should be made clear that all costs that have been deferred since June 2000 must be justified by the Company in a subsequent filing. The appropriate forum to conduct this review would be the next general rate case. The Company anticipates it will file a rate case in November 2001. In the event of a disallowance in the future, the Company should be required to pay refunds with interest.

CHANGED CIRCUMSTANCES

Q. DO YOU AGREE WITH THE COMPANY THAT FURTHER DETERIORATION IN HYDRO CONDITIONS AND WHOLESALE MARKET PRICES HAS CAUSED THE COMPANY TO FILE FOR THE RATE SURCHARGE?

A. Based upon my review, I can agree that the change in the Company's forward price forecast coupled with some very untimely and possibly imprudent purchases subsequent to the Stipulation have caused a substantial rise in the projected balance of the deferral account. I cannot, however, agree that the hydro conditions had a similar impact.

Q. WHY NOT?

A. The Company's filing, including both the petition and prefiled testimony, emphasizes that the Stipulation was based upon hydro generation being 135 average megawatts (aMW) below normal, that critical water conditions equate to 150 aMW below normal, and that current expectations are 194 aMW below normal. Thus, the Company states the 59 aMW difference in projected 2001 hydro generation at the time of the Stipulation and its current estimate of hydro supply is a significant factor contributing to the need for immediate rate relief. However, this representation is very misleading. Since at least May 4, 2001, the Company had projected hydro generation to be 172 aMW below normal. PS-67. Despite these projections, the Company's deferred balance forecast still showed the deferral balance would be less than $10 million by September 2002 without the imposition of a rate surcharge. PS-67. Thus, at best, the Company can only assert a hydro loss of just 22 aMW of generation since the Stipulation was submitted to the Commission for approval. Furthermore, even this estimate is highly dependent upon the forecast of hydro generation for the remainder of the year.

Q. HOW MUCH HYDRO GENERATION HAS THE COMPANY ASSUMED FOR THE REMAINDER OF THE YEAR?

A. The Company is predicting that its hydro generation will be 74 aMW below the critical water level for the second half of this year. The Company's actual and projected hydro generation for 2001 is contained on a workpaper provided with the filing labeled "PS_3." For ease of review, the following table shows the comparison between the previous critical water year's actual generation by the Company (January through June), and the projected generation for the remainder of the year taken from this workpaper.

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Hydro Generation 2001
(AMW)

Month	Critical Generation	Actual & **Projected**	Below Critical
Jan	318	392	-74
Feb	305	277	28
Mar	298	314	-15
Apr	344	382	-37
May	681	682	-2
June	752	609	143
July	365	**338**	**27**
Aug	389	**246**	**143**
Sep	260	**228**	**32**
Oct	272	**237**	**36**
Nov	353	**283**	**69**
Dec	471	**334**	**137**
Average	402	361	41
Jan-Jun	450	443	7
Jul-Dec	352	278	**74**

Note that the actual generation to date for the months of January through June was only 7 aMW below the previous critical water level for the Company. It is the Company's projection of hydro generation for the remaining months—July through December (indicated by the bold font in the above table)—that causes the overall water year to be 41 aMW worse than critical. It is likely that the actual hydro generation for the months of July, August and September should be relatively close to the Company's projection due to the historic limited precipitation that occurs during this period of the year. However, there is greater uncertainty with regard to the accuracy of the forecast for the months of October, November and December since one cannot readily predict how much rain will fall in these months. Certainly, December's forecast of only 334 aMW seems highly suspect, since it is below the previous lowest generating level the Company has ever experienced in that particular month.

Thus, the primary reason the Company is seeking the immediate rate surcharge is due to the market price decline that occurred subsequent to the Stipulation. Basically, the Company entered into several high priced spot market purchase power contracts near the time of, or subsequent to, the Stipulation, but prior to the June 19, 2001 FERC order imposing price caps on the Western power market. As a result, with the institution of the West-wide price caps, the Company is no longer anticipating sufficient wholesale market revenue to offset the deferrals. The likelihood of the FERC action was rumored and reported several days before the actual order was issued. Thus, a critical element of the prudence investigation covering this period will be analyzing the day-to-day activity and actions by the Company.

<u>AVISTA'S DEFERRED BALANCE PROJECTION</u>

Q. HAVE YOU HAD THE OPPORTUNITY TO REVIEW THE COMPANY'S DEFERRED BALANCE PROJECTION?

A. Yes. Although I would have liked more time to thoroughly analyze the underlying assumptions that were used to derive the forecast, I have a good understanding of the composition of the historical (or actual) deferred balance as of June 2001. In addition, I also understand the major cost elements comprising the future (or projected) period from July 2001 through December 2003.

Q. PLEASE DESCRIBE THE MAJOR ELEMENTS OF THE COMPANY'S DEFERRED POWER COST.

A. I have prepared Schedule 1 of Exhibit DWS-3 to present a simple summary of the components of the Company's power cost deferrals. I should note at the outset that the costs presented in Schedule 1 do not include any carrying cost or interest on the specific items. I will present this aspect of the deferral calculation later in the testimony.

For the actual balance booked from July 2000 through June 30, 2001, Schedule 1 shows the vast majority of deferrals are directly related to the turbulent wholesale market and near critical hydro conditions that characterized this period. This relation is readily apparent from reviewing line 1 of Schedule 1. Line 1 presents the difference between the actual net power costs incurred by the Company for such items as fuel and purchase power, less opportunity sales, versus the "authorized" level contained in the Company's recently established rates. For this period, the deferred balance for the Washington jurisdiction is $105.2 million (line 15 under the "Actual Deferral" column). As shown by line 16 of Schedule 1, it is also noteworthy that only 48% of the deferral recovery the Company is seeking is associated with this extraordinary market period. The remaining 52% of the deferred balance is a direct result of the Company's forecast of the market conditions that will occur during the next thirty months.

More troubling to me in viewing Schedule 1 are the new resource cost categories that the Company seeks to immediately recover under the "Projected Deferral" column. As is readily apparent, the Company has included all the fixed capital, operations, and maintenance expenses associated with a host of new generating resources. Typically, costs such as these would not be granted "pre-recovery" until a prudence review had been completed or the units had actually passed commercial viability performance testing. These resource decisions should be thoroughly analyzed in a general rate case or a proceeding specifically focusing on their prudence. The Commission should also assess whether it is prudent to complete construction of these generating resources given current market conditions. As presented by line 17 of Schedule 1, the new resource fixed costs represent 54% of the projected deferral. After adding this value to the variable costs associated with these resources, such as substantial prices for Coyote Springs II fuel cost (included on Line 1), the projected resource-related deferral percentage would be even higher.

RECOMMENDATION IF THE COMMISSION GRANTS A SURCHARGE

Q. IF THE COMMISSION DECIDES A TEMPORARY SURCHARGE IS APPROPRIATE AT THIS TIME, SHOULD IT BE FOR THE ENTIRE AMOUNT THE COMPANY HAS PROPOSED?

A. No. If that were to occur, the Company would receive ratepayer capital based upon speculative forecast assumptions, highly questionable power purchase transactions and fuel costs. These types of items should never be allowed in rates and certainly not included in a temporary surcharge, even if it is subject to refund. In addition, it would essentially allow immediate recovery of new resource-related costs without any review as to the prudence of the Company's actions. Accordingly, I recommend that if the Commission authorizes the Company to recover any of the deferred costs through an interim rate surcharge, the focus should be on the appropriate amount of the actual costs that have been deferred through June 2001.

In determining the amount of the surcharge, if any, the Commission should consider what amount would likely be authorized after a reasonableness review in a general rate case.

Q. HOW CAN THIS VALUE BE APPROXIMATED?

A. I believe that there is a straightforward method to determine a reasonable "placeholder" value. This value would be used as the starting point in determining whether a ratepayer surcharge is needed at this time. The approach would start with all of the Company's reported cost and sales transactions, and the Commission approved deferral calculation methods would be used (but subject to the outcome of the prudence review). However, whereas the Company's deferral calculation has compared these costs to its authorized recovery level, I would compare the actual costs to the "risk adjusted" authorized rate level.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY RISK ADJUSTED AUTHORIZED RATE LEVEL.

A. In the traditional rate setting process, both ratepayers and Company shareholders take on certain risks. With regard to power-related costs, the Company assumes the risk that market prices and/or hydro generation could deviate from the expected level and cause a power cost increase and utility earning decrease. On the other hand, the Company's customers take on the risk that actual power costs could be below "authorized" levels due to better than anticipated market or hydro conditions. This risk sharing mechanism is implemented by establishing rates based on a normalized test year. While no one could have reasonably anticipated the extraordinary market conditions that occurred from July 2000 through June 2001, the Company's 60 year power cost simulation reflects the Company's acceptance of a certain amount of market and hydro risk in establishing rates. I recommend that the Commission adjust the "authorized" power cost used in the deferral calculation to reflect the explicit risk that the Commission adopted in establishing the authorized rates for the Company. Any additional market risk resulting from the Company's actual cost being above this "risk adjusted authorized" level during this period would be the responsibility of the Company's ratepayers.

Q. HOW CAN THIS RISK ADJUSTMENT BE QUANTIFIED?

A. I recommend that a "placeholder" adjustment be calculated using the results taken directly from the Company's dispatch model. The adjustment can be determined by comparing the average short-term net power cost projected by the model under all water conditions to the cost incurred under the lowest water conditions. The following table presents the summary results of the Company's dispatch model by month for the average of the sixty water years, along with the two lowest water years—1937 and 1988.

Net Power Cost Comparison
(1000 Dollars)

Month	60 Yr Avg	1937	1988	1937 -Avg	1988 -Avg
July	$3,468	$9,675	$9,155	$6,209	$5,688
Aug	4,171	5,794	6,226	1,623	2,055
Sep	5,743	8,541	8,214	2,798	2,471
Oct	5,763	8,514	7,706	2,751	1,943
Nov	4,212	7,250	7,654	3,038	3,441
Dec	3,894	6,983	7,035	3,090	3,142
Jan	4,467	9,372	8,122	4,905	3,655
Feb	2,501	6,881	5,870	4,380	3,368
Mar	3,532	8,556	7,566	5,024	4,034
Apr	4,318	11,565	4,536	7,247	219
May	-366	2,488	1,636	2,854	2,002
Jun	1,247	3,565	7,421	2,318	6,174
Total	$42,948	$89,185	$81,139	$46,237	$38,191
WASH	$28,771	$59,745	$54,355	$30,974	$25,584

As indicated by the above table, the Company's short-term net power cost under the 1937 water condition is over twice the 60 year average ($89.2 million versus $42.9 million), equating to a Washington jurisdictional difference of $31.0 million. Similarly, the power cost under the 1988 water condition reflects a $38.2 million total system increase and $25.6 million for Washington. In recognition of the dispute among the parties over the correct number of water years to employ in deriving the expected power costs, I recommend that the Commission adopt a jurisdictional risk adjustment of $25.6 million based upon the 1988 water condition since it falls within the most recent 40 years of water record.

Q. HAVE YOU DETERMINED WHAT IS THE APPROPRIATE PORTION OF THE COMPANY'S DEFERRAL BALANCE THAT SHOULD BE BORNE BY RATEPAYERS?

A. Yes. I have prepared a series of schedules contained in Exhibit DWS-3 to summarize and replicate the mechanics used by the Company in order to determine the appropriate "starting point" or deferral value under my recommendation. Schedules 2 and 3 of Exhibit DWS-3 set forth the calculation of the deferred cost that should be assigned to the Company's ratepayers. These schedules essentially replicate the calculations presented on pages 3 and 4 of Exhibit ___(KON-6). Schedule 2 calculates the deferral for the July 2000 through November 2000 period, with an additional line (designated as 34a) for the 1988 market/water risk adjustment. I have also added line 40a to this schedule to indicate the accumulated deferred balance for Washington, excluding interest. Schedule 3 performs the deferral calculation for the months of December 2000 through June 2001. Line 12a contains the 1988 market/water risk adjustment while line 18a continues to accumulate the Washington deferral from line 40a of Schedule 2. I have also added line 16a denoting the jurisdictional customer buyback cost that was separately recorded in the Company's deferral calculations. As can be seen under the June column, the accumulated deferral is $81.3 million. In my view, this is the maximum amount of cost deferral from this period which should be considered by the Commission for possible recovery from the Company's ratepayers.

Schedule 4 of Exhibit DWS-3 presents the application of interest to the monthly deferrals. The top half of the schedule shows the interest assignment using the Company's deferrals while the bottom half applies the same interest calculation to my recommended recoverable balances. With the inclusion of interest, my "starting point" deferral balance is $83.1 million as of June 30, 2001, compared to the Company's value of $109.4 million.

Q. HOW CAN THIS AMOUNT BE RECOVERED FROM THE COMPANY'S RATEPAYERS?

A. The Company's proposed two step method should be used. First, accelerating the amortization of the PGE monetization over a 15 month period should offset a portion of the deferral. This amount is $53.8 million. The remaining balance should be recovered through a rate surcharge over a reasonable period of time.

By further replication of the Company's analytical methods, I was able to determine that a 15 month surcharge of 11.9% would be required to reduce the June 30, 2001 risk adjusted balance to zero by December 2002. This results in an additional $28.3 million per year from the Company's ratepayers. Schedule 5 of Exhibit DWS-3 compares the Company's proposed surcharge with my surcharge percentage recommendation. A chart indicating the successful recovery of the June 30, 2000 recoverable balance by December 2002 is presented as Schedule 6 of Exhibit DWS-3. Schedules 5 and 6 of Exhibit DWS-3 essentially replicate pages 1 and 2 of Exhibit ___(DMF-1).

Finally, Schedule 7 of Exhibit DWS-3 compares the class specific assignment of the Company's and my recommended rate surcharge using an equal percentage method. As presented by this schedule, I recommend that the Company's surcharge amount be reduced by $59.1 million per year. In addition, I recommend that the surcharge remain in place for 15 months as compared to the Company's 27 month period.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.