Avista Corp.
1411 East Mission PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

August 8, 2002

State of Idaho
Idaho Public Utilities Commission
Statehouse
Boise, ID 83720

Attention: Ms. Jean Jewell, Secretary

Submission of PCA Status Report and
Application for Continuation of PCA Surcharge

Enclosed for filing with the Commission is an original and seven copies of the Company's Status Report on its Power Cost Adjustment (PCA) mechanism and Application for Continuation of the existing PCA surcharge. The surcharge was authorized by the Commission in Order No. 28876 in Case No. AVU-E-01-11. Also enclosed is an original and nine copies of supporting testimony, 3 copies of associated workpapers and an electronic version of the filing on a compact disc.

The existing tariff sheet Sixth Revision Sheet 66 sets forth rates to recover power costs in excess of costs presently included in rates and represents a 19.4%% increase over present rates to all classes of retail customers. The Company requests that the current PCA tariff be authorized for another 12 months, from October 12, 2002 through October 11, 2003.

In addition to the items listed above, please find enclosed a Certificate of Service, a copy of the Press Release the Company will be issuing on August 9, 2002, as well as a copy of the Customer Notice. The Company will begin mailing the notice of the proposed surcharge continuation to all customers on August 12, 2002.

Please direct any questions regarding this filing to Don Falkner at (509) 495-4326 or Ron McKenzie at (509) 495-4320.

Sincerely,

Kelly Norwood

Kelly Norwood
Vice-President, Rates and Regulation

Enc.

Kelly O. Norwood
Vice-President, Rates and Regulation
1411 E. Mission Avenue
P. O. Box 3727
Spokane, Washington 99220
Phone: (509) 495-4267, Fax: (509) 495-8856

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE SUBMISSION OF THE STATUS REPORT OF AVISTA CORPORATION AND APPLICATION FOR A CONTINUATION OF A POWER COST ADJUSTMENT (PCA) SURCHARGE	)))))	CASE NO. AVU-E-_______

I. INTRODUCTION

Avista Corporation doing business as Avista Utilities (hereinafter Avista or Company), at 1411 East Mission Avenue, Spokane, Washington, respectfully files the status report as required by the Commission[1], and requests the Commission for an order approving recovery of power costs deferred through June 30, 2002 and granting continuation of the PCA surcharge of 19.4% currently scheduled to expire on October 11, 2002. This surcharge was authorized by this Commission in Order No. 28876 in Case No. AVU-E-01-11.

Pursuant to the above referenced Order, this filing, along with the attached testimony and associated workpapers (incorporated herein by reference), serve as the status report which was required to be filed 60 days prior to the expiration of the term of the surcharge. The Company has developed a straightforward filing and requests that the status report and continuation request be

[1] As stated by the Commission at page 1 of its Order No. 28876: "We direct the Company to file a status report 60 days prior to the expiration of the term. If that status report and our review of the actual PCA deferral balance

processed under the Commission's Modified Procedure rules. As the Company will explain in this filing, continuation of the current surcharge is not only justified by the current level of unrecovered power cost deferrals, but is essential to the continued improvement in the financial health of the Company and efforts to regain an investment grade credit rating as soon as possible.

Due to the high levels of deferred energy costs and other uncertainties, and despite approval by the Commission of the current PCA surcharge, the Company's credit ratings were lowered by credit rating agencies to below investment grade in October of 2001. Over time, the added financing costs resulting from continuing to be below investment grade would work to the detriment of customers.

Communications in reference to this Application should be addressed to:

Kelly O. Norwood
Vice-President, Rates and Regulation
Avista Corporation
1411 E. Mission Avenue
Spokane, Washington 99220
Phone: (509) 495-4267
Fax: (509) 495-8856

David J. Meyer
Senior Vice-President and General Counsel
Avista Corporation
1411 E. Mission Avenue
Spokane, Washington 99220
Phone: (509) 489-0500
Fax: (509) 495-4361

II. CONTINUATION REQUEST

On page 1 of Order 28876, the Commission directed the Company to "file a status report" 60 days prior to the expiration of the surcharge term and went on to state, "If that status report and our review of the actual PCA deferral balance supports continuation of the surcharge, we anticipate continuation of the surcharge for an additional period." The current status of the unrecovered PCA deferral balance as of June 30, 2002 is $45,600,228 for our Idaho jurisdiction.

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supports continuation of the surcharge, we anticipate continuation of the surcharge for an additional period."

Through this filing, the Company is requesting that the Commission continue the PCA surcharge for an additional 12 months, through October 11, 2003. Continuing the existing surcharge for an additional 12 months would provide recovery of an additional $23.6 million of the deferral balance. Although the June 30, 2002 deferral balance of $45.6 million indicates that the current surcharge would need to stay in place beyond October 2003, in keeping with the Commission's previous decision to keep "a period consistent with existing PCA methodology," the Company requests at this time that the surcharge stay in place for another 12-month period.

As explained in testimony by Mr. Ron McKenzie, Schedule 66 would remain unchanged. The existing Schedule 66 contains the currently effective surcharge rates that the Company is requesting be extended for an additional twelve months. Under the Special Terms and Conditions on the tariff is a statement that, "The rates set forth under this Schedule are subject to periodic review and adjustment by the IPUC based on the actual balance of deferred power costs."

Monthly reports have been filed with the Commission Staff regarding actual PCA deferral entries to date. To facilitate Staff's review, additional copies of those reports have been included with this filing and have also been provided to Potlatch Corp. who intervened in AVU-E-01-11. As already noted, the Company requests that this filing be processed under Commission's Modified Procedure rules noting that the request is for a continuation of a previously authorized surcharge under the long-standing PCA mechanism. The rates associated with this surcharge would not change as a result of this filing.

III. DEFERRED COST BALANCES AND POWER SUPPLY CONDITIONS

The deferral balance of $45.6 million at June 30, 2002 is shown below, together with the changes in the balance since June 30, 2001. Mr. McKenzie's testimony explains each of the changes in the deferral balance and Mr. Norwood's testimony provides additional explanation of the factors causing the deferral entries of $48.4 million for the period July 2001 through June 2002.

Deferral balance at June 30, 2001	$30,007,057	
Deferrals July 2001 through June 2002	48,442,371	
Transfer of under-rebate	-49,073	
Transfer of under-surcharge	342,069	
PGE monetization accelerated amortization	-20,783,521	
Interest	2,764,590	
Subtotal – Account 186.38 balance at June 30, 2002	60,723,493	
Revenues collected October 12, 2001 – June 30, 2002	-15,123,265	*
Unrecovered balance at June 30, 2002	$45,600,228	

*(8 ½ months)

As was explained in last year's PCA surcharge filing, hydroelectric generation through June 2001 for Avista was the lowest in the 73 years of record. As Mr. Norwood explains in his testimony, the Company continued to experience those very low streamflow conditions through the remainder of 2001. The record low hydroelectric conditions in 2001 required the Company to purchase energy in the forward short-term wholesale market to replace the lost generation and cover its energy deficiencies. These purchases were made at unprecedented high wholesale market prices, and caused deferral balances to increase substantially. The extraordinary power supply circumstances through mid-2001, especially the record low streamflows, continued to impact the Company's power cost deferral balances for the remainder of the year and into 2002. In fact, of the deferrals of $48.4 million recorded between July 2001 and June 2002, approximately $46 million occurred during the last half of 2001 with the remaining $2 million occurring in the first half of 2002.

Mr. Norwood will also address measures taken by the Company to mitigate the increased power costs, such as increased operation of its thermal resources, aggressively pursuing conservation and load curtailment programs. However, the costs associated with the hydroelectric conditions, the cost of short-term market purchases and increased thermal fuel costs have exceeded the benefits these measures provided.

IV. FINANCIAL IMPLICATIONS

Attachment 1 includes a chart showing the electric deferral balance for the Idaho jurisdiction for each month of the 12-month period ending June 30, 2002 and shows the $45.6 million balance at June 30, 2002. Investor concerns surrounding cash flows, deferral balances and the ability to recover costs in a timely manner have had an impact on the Company's financings that continues today.

As stated earlier, Avista's credit ratings are below investment grade and the rating agencies characterize the Company's outlook as negative. This is evidenced in Standard & Poor's July 22, 2002 listing of "U.S. Electric/Gas/Water Companies," included as Attachment 2, where Avista is ranked 304th out of 320 utilities rated by S&P. Because of Avista's present credit ratings, debt is more expensive. It is imperative for both the Company and our customers that Avista continue to improve its financial condition so that investment grade credit ratings can be restored. The Company's current credit ratings are summarized in the table below:

	Standard & Poor's	Moody's	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB+
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB

On a positive note, the Company renewed its short-term line of credit on May 21, 2002, where the Company entered into a committed line of credit with various banks in the total amount of $225.0 million. The line of credit expires on May 20, 2003 and replaces the $220.0 million line of credit that expired on May 29, 2002. It is important for the Company to regain an investment grade credit rating as soon as possible so that longer term debt can be refinanced on more reasonable terms, benefiting customers with lower debt-related costs. Credit ratings will take time to be restored and continuation of the current surcharge is one of the keys for the Company to continue to improve its financial condition.

As explained in more detail in the testimony of Mr. Ronald McKenzie, the Company requests that the carrying charge applied to the unamortized PCA deferral balance be increased from the current customer deposit rate to a level more reflective of the longer-term nature of the recovery period. The Company's embedded cost of debt as of June 30, 2002 is 8.88%, incorporating both long and short-term debt. However, the Company proposes that the carrying charge be increased to a rate of 6%, as was recently authorized for Idaho Power.

The Company needs continued access to capital on reasonable terms to continue operations, to refund maturing debt, and to pay for facilities to serve customers. Commission support and action through continuation of the surcharge is important in that regard.

V. NO TARIFF CHANGES

The rates set forth under the proposed PCA Schedule 66 reflect an annual revenue surcharge amount of $23.6 million, or 19.4%. As proposed by the Company, the Schedule 66 rates would not change. The use of the deferred credit related to the monetization of the Portland General Electric (PGE) Sale Agreement as an offset to the power cost deferral balance to reduce the overall rate impact to customers will continue through the end of 2002. After that point, the ongoing PCA deferral entries will be adjusted to reflect the fact that the PGE credit has been fully returned to customers.

The Company proposes the continuation of the surcharge for a 12-month period, beginning October 12, 2002 and continuing through October 11, 2003. The Company would again will file prior to the expiration of that term, and propose continuation of the surcharge as necessary to allow recovery of any unrecovered PCA balance at that time.

VII. REQUEST FOR RELIEF

The Company respectfully requests the Commission for an order approving recovery of power costs deferred through June 30, 2002 and granting continuation of the PCA surcharge of 19.4% through October 11, 2003. The Company also requests that the interest rate being applied to the unrecovered PCA deferral balance be increased to 6% to reflect the longer-term recovery period for these deferrals. The Company submits that this status report filing and request for the continuation of the existing surcharge is straightforward and warrants expedited processing under the Commission's Modified Procedure rules so that the surcharge would continue to allow recovery of power supply costs incurred to serve our customers, thereby reducing the size of the PCA deferral balance.

Dated at Spokane, Washington this 8th day of August 2002.

AVISTA CORPORATION

BY Kelly O. Norwood

Kelly O. Norwood
Vice-President, Rates and Regulation

VERIFICATION

STATE OF WASHINGTON)
)
County of Spokane)

Kelly O. Norwood, being first duly sworn on oath, deposes and says: That he is the Vice-President, Rates and Regulation of Avista Corporation and makes this verification for and on behalf of said corporation, being thereto duly authorized;

That he has read the foregoing filing, knows the contents thereof, and believes the same to be true.

Kelly O. Norwood

SIGNED AND SWORN to before me this 8th day of August 2002, by Kelly O. Norwood.

Anita L. Grafmiller

NOTARY PUBLIC in and for the State of Washington, residing at Spokane.

Commission Expires: 6/17/05

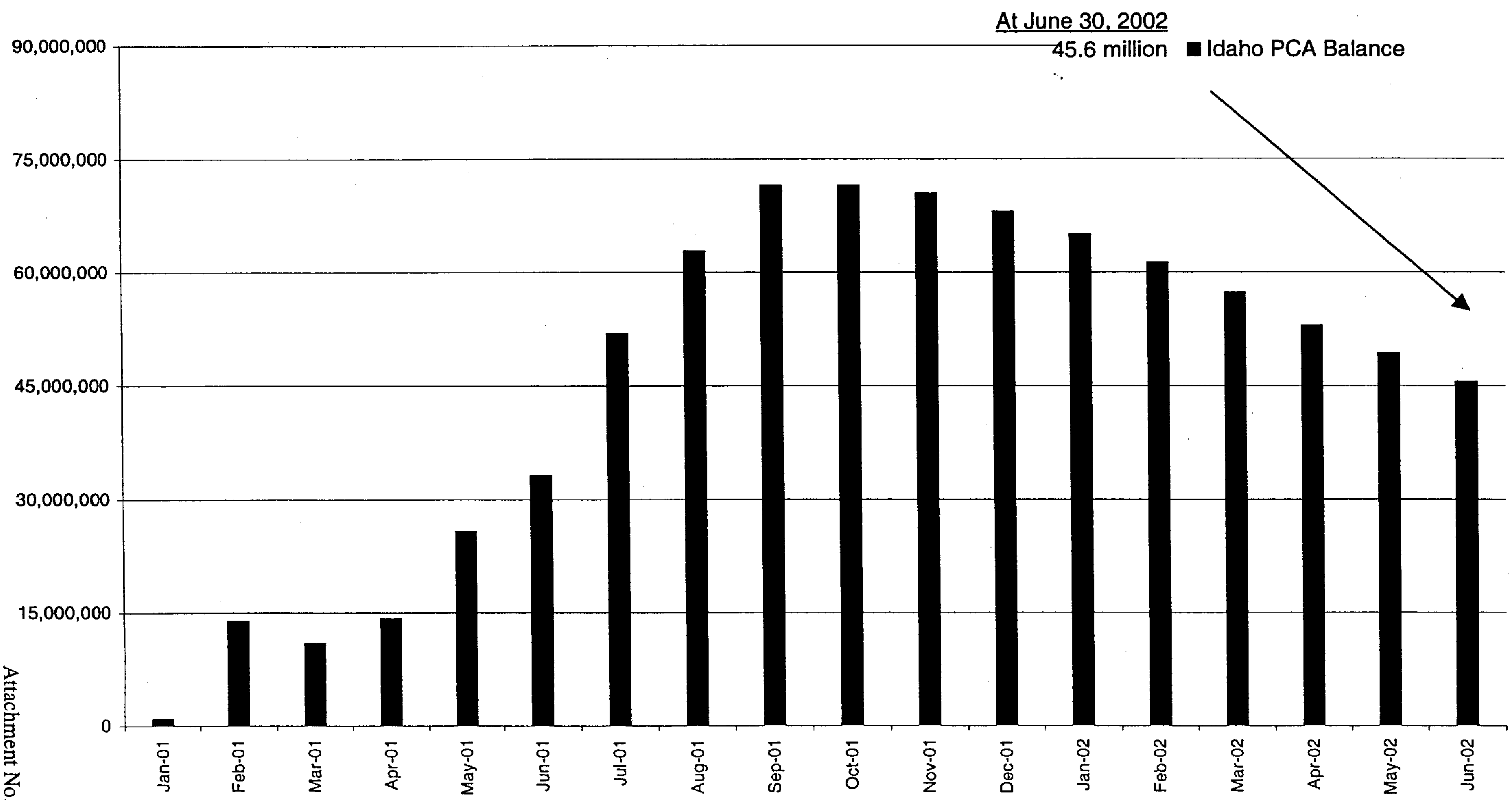
ANITA L. GRAFMILLER
NOTARY PUBLIC
STATE OF WASHINGTON
COMMISSION EXPIRES JUNE 17, 2005

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

ATTACHMENT NO. 1

Electric Deferral Balances
Actuals through June 30, 2002



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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

ATTACHMENT NO. 2

The following list contains Standard & Poor's Ratings, Outlooks, and Business Profiles for utilities. This list, dated July 18, 2002, reflects the most current ratings, rankings, and outlooks. It is arranged by corporate credit rating categories. Within corporate credit rating categories, issuers are grouped by Outlooks; and within Outlook categories, issuers are listed by RELATIVE STRENGTH, with the first being the strongest, and the last being the weakest.

A Standard & Poor's rating Outlook assesses the potential direction of an issuer's long-term debt rating over the intermediate to longer term. In determining a rating Outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An Outlook is not necessarily a precursor of a rating change or future CreditWatch action. "Positive" indicates that a rating may be raised; "Negative" means a rating may be lowered; "Stable" indicates that ratings are not likely to change; and "Developing" means ratings may be raised or lowered. N.M. means not meaningful.

Utility business profiles are categorized from 1 (strong) to 10 (weak). In order to determine a utility's business profile, Standard & Poor's analyzes the following qualitative business or operating characteristics typical of a utility: markets and service area economy; competitive position; fuel and power supply; operations; asset concentration; regulation; and management. Telecommunications companies have not been assigned business profiles. Issuer credit ratings, shown as long-term rating/outlook or CreditWatch/short-term rating, are local and foreign currency unless otherwise noted. A dash '—' indicates not rated. An asterisk '*' indicates that the utility was reviewed this week and its ranking position was updated.

U.S. Electric/Gas/Water Companies

Company	Corporate Credit Rating	Bus. Prof.
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Baton Rouge Water Works Co. (The)	AA/Stable/—	2
Madison Gas & Electric Co.	AA/Negative/A-1+	5
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
California Water Service Co.	AA-/Stable/—	3
Wisconsin Public Service Corp.	AA-/Stable/A-1	4
Peoples Gas Light & Coke Co.	AA-/Negative/A-1+	3
North Shore Gas Co.	AA-/Negative/A-1+	3
Elizabethtown Water Co.	AA-/Negative/—	3
Elizabethtown Corp.	AA-/Negative/—	4
Southern California Water Co.	A+/Stable/—	3
Southern California Gas Co.	A+/Stable/A-1	2
San Diego Gas & Electric Co.	A+/Stable/A-1	5
American States Water Co.	A+/Stable/—	3
Philadelphia Suburban Water Co.	A+/Stable/—	2
Consolidated Edison Co. of New York Inc.	A+/Stable/A-1	3
Consolidated Edison Inc.	A+/Stable/A-1	3
Orange and Rockland Utilities Inc.	A+/Stable/A-1	3
Rockland Electric Co.	A+/Stable/—	4
KeySpan Energy Delivery New York	A+/Stable/—	2
KeySpan Energy Delivery Long Island	A+/Stable/—	2
Laclede Gas Co.	A+/Stable/A-1	3
Laclede Group Inc.	A+/Stable/—	3
Otter Tail Power Co.	A+/Stable/A-1	6
WPS Resources Corp.	A+/Stable/A-1+	5
Questar Gas Co.	A+/Negative/—	2
Questar Pipeline Co.	A+/Negative/—	3
Peoples Energy Corp.	A+/Negative/A-1	4
Union Electric Co.	A+/CW-Neg/A-1	4
Central Illinois Public Service Co.	A+/CW-Neg/A-1	3
Ameren Corp.	A+/CW-Neg/A-1	5
*Duke Energy Corp.	A+/CW-Neg/A-1	5
*Duke Capital Corp.	A+/CW-Neg/A-1	6
*Texas Eastern Transmission L.P.	A+/CW-Neg/—	4
*PanEnergy Corp.	A+/CW-Neg/—	4
New Jersey-American Water Co.	A/CW-Pos/—	3
Central Hudson Gas & Electric Co.	A/Positive/—	3
New Jersey Natural Gas Co.	A/Positive/A-1	2
Aquarion Co.	A/Stable/—	3
BHC Co.	A/Stable/—	2
Middlesex Water Co.	A/Stable/—	3
Colonial Pipeline Co.	A/Stable/A-1	3
Montana-Dakota Utilities Co.	A/Stable/—	4
MDU Resources Group Inc.	A/Stable/A-1	5
Piedmont Natural Gas Co. Inc.	A/Stable/—	3
ONEOK Inc.	A/Stable/A-1	5
Boston Gas Co.	A/Stable/—	3
Colonial Gas Co.	A/Stable/—	3
Massachusetts Electric Co.	A/Stable/A-1	3
Narragansett Electric Co.	A/Stable/A-1	3
New England Power Co.	A/Stable/A-1	3
Niagara Mohawk Power Corp.	A/Stable/—	4
National Grid USA	A/Stable/A-1	3
NSTAR	A/Stable/A-1	3
Boston Edison Co.	A/Stable/A-1	3
Commonwealth Electric Co.	A/Stable/—	3
NSTAR Gas Co.	A/Stable/—	3
Cambridge Electric Light Co.	A/Stable/—	3
Buckeye Partners L.P.	A/Stable/—	4
KeySpan Generation LLC	A/Stable/—	4
KeySpan Corp.	A/Stable/A-1	3
Wisconsin Gas Co.	A/Stable/A-1	3
Wisconsin Electric Power Co.	A/Stable/A-1	4
Wisconsin Power & Light Co.	A/Stable/A-1	4
Virginia Electric & Power Co.	A/Stable/A-1	4
MidAmerican Energy Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/—	4
Georgia Power Co.	A/Stable/A-1	4
Savannah Electric & Power Co.	A/Stable/—	4
Southern Co.	A/Stable/A-1	4
Equitable Resources Inc.	A/Stable/A-1	5
Atlantic City Sewerage Co.	A/Stable/—	3
Beckley Water Co.	A/Stable/—	4
Public Service Co. of North Carolina Inc.	A/Negative/A-1	3
South Carolina Electric & Gas Co.	A/Negative/A-1	4
SCANA Corp.	A/Negative/—	4
Florida Power & Light Co.	A/CW-Neg/A-1	4
FPL Group Inc.	A/CW-Neg/—	6
FPL Group Capital	A/CW-Neg/A-1	8
Northwest Natural Gas Co.	A/CW-Neg/A-1	3
IDACORP Inc.	A-/Positive/A-2	5
Idaho Power Co.	A-/Positive/A-1	4
United Water New Jersey	A-/Stable/—	3
United Water Works	A-/Stable/—	3
NOVA Gas Transmission Ltd.	A-/Stable/—	2
TransCanada Pipelines Ltd.	A-/Stable/—	2
Atlanta Gas Light	A-/Stable/—	2
Alabama Gas Corp.	A-/Stable/—	2
Energen Corp.	A-/Stable/—	6
AGL Resources Inc.	A-/Stable/—	3
American Transmission Co.	A-/Stable/A-2	2
Interstate Power & Light Co.	A-/Stable/A-2	5

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Attachment No. 2
Case No. AVU-E-____
Avista
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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Alliant Energy Corp.	A-/Stable/A-2	5
Alliant Energy Resources Inc.	A-/Stable/A-2	8
PG&E Gas Transmission-Northwest	A-/Stable/A-2	2
PPL Electric Utilities Corp.	A-/Stable/A-2	4
Baltimore Gas & Electric Co.	A-/Stable/A-1	3
Atmos Energy Corp.	A-/Stable/A-2	4
Kinder Morgan Energy Partners L.P.	A-/Stable/A-2	4
Indiana Gas Co. Inc.	A-/Stable/A-2	2
Southern Indiana Gas & Electric Co.	A-/Stable/—	5
Vectren Energy Delivery of Ohio	A-/Stable/—	4
Vectren Utility Holdings	A-/Stable/A-2	4
Vectren Corp.	A-/Stable/—	4
PECO Energy Co.	A-/Stable/A-2	4
Commonwealth Edison Co.	A-/Stable/A-2	4
Exelon Generation Co.	A-/Stable/—	8
Exelon Corp.	A-/Stable/A-2	6
Sempra Energy	A-/Stable/A-1	4
Wisconsin Energy Corp.	A-/Stable/A-2	5
Constellation Energy Group Inc.	A-/Stable/A-1	6
Delmarva Power & Light Co.	A-/Stable/A-2	3
PacifiCorp	A-/Negative/A-1	4
Oklahoma Gas & Electric Co.	A-/Negative/—	4
OGE Energy Corp.	A-/Negative/A-2	5
Enogex Inc.	A-/Negative/—	6
Northern Border Pipeline Co.	A-/Negative/—	3
Northern Border Partners L.P.	A-/Negative/—	3
National Fuel Gas Co.	A-/Negative/A-2	5
Tampa Electric Co.	A-/Negative/A-2	4
TECO Energy Inc.	A-/Negative/A-2	5
Teco Finance Inc.	A-/Negative/—	8
UGI Utilities Inc.	A-/Negative/—	4
Duke Energy Trading and Marketing LLC	A-/CW-Neg/—	8
Kern River Gas Transmission Co.	A-/CW-Neg/—	4
Louisville Gas & Electric Co.	BBB+/CW-Pos/A-2	4
Kentucky Utilities Co.	BBB+/CW-Pos/A-2	4
AmerenEnergy Generating Co.	BBB+/CW-Pos/—	7
LG&E Energy Corp.	BBB+/CW-Pos/—	6
LG&E Capital Corp.	BBB+/CW-Pos/A-2	8
South Jersey Gas Co.	BBB+/Stable/—	3
Reliant Energy Inc.	BBB+/Stable/A-2	3
Reliant Energy Resources Corp.	BBB+/Stable/A-2	3
El Paso Natural Gas Co.	BBB+/Stable/A-2	4
Tennessee Gas Pipeline Co.	BBB+/Stable/A-2	4
ANR Pipeline Co.	BBB+/Stable/—	4
Pepco Holdings Inc.	BBB+/Stable/A-2	4
Colorado Interstate Gas Co.	BBB+/Stable/—	3
Coastal Corp.	BBB+/Stable/—	6
Southern Natural Gas Co.	BBB+/Stable/—	4
El Paso Corp.	BBB+/Stable/A-2	6
El Paso Tennessee Pipeline Co.	BBB+/Stable/—	4
Cascade Natural Gas Corp.	BBB+/Stable/—	3
NorthWestern Corp.	BBB+/Stable/—	5
Connecticut Light & Power Co.	BBB+/Stable/—	4
Western Massachusetts Electric Co.	BBB+/Stable/—	4
Public Service Co. of New Hampshire	BBB+/Stable/—	5
Northeast Utilities	BBB+/Stable/—	5
Consolidated Natural Gas Co.	BBB+/Stable/A-2	5
Dominion Resources Inc.	BBB+/Stable/A-2	5
Northwestern Energy LLC	BBB+/Stable/A-2	4
Arizona Public Service Co.	BBB+/Stable/A-2	3
Maui Electric Co. Ltd.	BBB+/Stable/A-2	6
Hawaiian Electric Light Company	BBB+/Stable/A-2	6
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Central Power & Light Co.	BBB+/Stable/—	2
Appalachian Power Co.	BBB+/Stable/—	3
Columbus Southern Power Co.	BBB+/Stable/—	2
Indiana Michigan Power Co.	BBB+/Stable/—	4
Kentucky Power Co.	BBB+/Stable/—	3
Ohio Power Co.	BBB+/Stable/—	2
Public Service Co. of Oklahoma	BBB+/Stable/—	3
Southwestern Electric Power Co.	BBB+/Stable/—	3
West Texas Utilities Co.	BBB+/Stable/—	2
AEP Resources Inc.	BBB+/Stable/—	7
American Electric Power Co. Inc.	BBB+/Stable/A-2	5
West Penn Power Co.	BBB+/Stable/A-1	2
Potomac Edison Co.	BBB+/Stable/A-1	2
Monongahela Power Co.	BBB+/Stable/A-1	2
Allegheny Energy Inc.	BBB+/Stable/A-1	5
Allegheny Generating Co.	BBB+/Stable/A-2	7
Allegheny Energy Supply Co. LLC	BBB+/Stable/A-2	7
Detroit Edison Co.	BBB+/Stable/A-2	6
MCN Energy Enterprises Inc.	BBB+/Stable/A-2	8
DTE Enterprises	BBB+/Stable/—	6
DTE Energy Co.	BBB+/Stable/A-2	6
Cinergy Corp.	BBB+/Stable/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/—	4
PSI Energy Inc.	BBB+/Stable—	4
Union Light Heat & Power Co.	BBB+/Stable/—	4
Cleco Utility Group Inc.	BBB+/Stable/A-2	5
Cleco Corp.	BBB+/Stable/A-2	6
Potomac Electric Power Co.	BBB+/Stable/A-2	3
Conectiv	BBB+/Stable /A-2	4
Atlantic City Electric Co.	BBB+/Stable/A-2	3
Allete Inc.	BBB+/Stable/A-2	7
Southern Union Co.	BBB+/Stable/—	3
Providence Gas Co.	BBB+/Stable/—	3
Valley Gas Co.	BBB+/Stable/—	4
Valley Resources Inc.	BBB+/Stable/—	5
PG&E Energy Trading Holdings Co.	BBB+/Stable/—	8
Northwest Pipeline Co.	BBB+/Stable/A-2	3
TXU U.S. Holdings	BBB+/Stable/A-2	5
TXU Electric Delivery Co.	BBB+/Stable/A-2	5
TXU Energy Co.	BBB+/Stable/A-2	5
TXU Corp.	BBB+/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Negative/—	4
Midwest Independent Transmission System Operator Inc.	BBB+/Negative/—	3
Florida Power Corp.	BBB+/Negative/A-2	4
Carolina Power & Light Co	BBB+/Negative/A-2	5
Florida Progress Corp.	BBB+/Negative/A-2	5
Progress Energy Inc.	BBB+/Negative/A-2	5
Connecticut Natural Gas Corp.	BBB+/Negative/—	3
Southern Connecticut Gas Co.	BBB+/Negative/—	3
Central Maine Power Co.	BBB+/Negative/A-2	3
New York State Electric & Gas Corp.	BBB+/Negative/A-2	4
Energy East Corp.	BBB+/Negative/—	3
Rochester Gas & Electric Corp.	BBB+/Negative/—	5
RGS Energy Group Inc.	BBB+/Negative/—	5
Dayton Power & Light Co.	BBB+/Negative/A-2	4
DPL Inc.	BBB+/Negative/A-2	6
Portland General Electric Co.	BBB+/CW-Neg/A-2	4
TEPPCO Partners L.P.	BBB/Stable/—	4
TE Products Pipeline Co. L.P.	BBB/Stable/—	4
Florida Gas Transmission Co.	BBB/Stable/—	2
NUI Corp.	BBB/Stable/—	3
Kinder Morgan Inc.	BBB/Stable/A-2	5
PPL Energy Supply LLC	BBB/Stable/—	7
PPL Corp.	BBB/Stable/A-2	7
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
PSEG Power LLC	BBB/Stable/—	7

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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Public Service Enterprise Group Inc.	BBB/Stable/A-2	6
PSEG Energy Holdings, Inc.	BBB/Stable	8
Bangor Hydro-Electric Co.	BBB/Stable/—	5
Entergy Arkansas Inc.	BBB/Stable/—	6
Entergy Louisiana Inc.	BBB/Stable/—	6
Entergy Mississippi Inc.	BBB/Stable/—	7
Entergy New Orleans Inc.	BBB/Stable/—	7
Entergy Corp.	BBB/Stable/—	6
Pinnacle West Capital Corp.	BBB/Stable/—	5
Pinnacle West Energy Corp.	BBB/Stable/—	7
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Great Plains Energy Inc.	BBB/Stable/—	6
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Black Hills Power Inc.	BBB/Stable/—	5
Black Hills Corp.	BBB/Stable/A-2	7
Potomac Capital Investment Corp.	BBB/Stable/A-2	7
Empire District Electric Co.	BBB/Stable/A-2	5
Xcel Energy Inc.	BBB/Negative/A-3	6
Northern States Power Co.	BBB/Negative/A-3	4
Southwestern Public Service Co.	BBB/Negative/A-3	4
Public Service Co. of Colorado	BBB/Negative/A-3	4
NRG Energy Inc.	BBB/Negative/	9
PacifiCorp Group Holdings Co.	BBB/Negative/A-2	4
Jersey Central Power & Light Co.	BBB/Negative/A-2	4
Pennsylvania Electric Co.	BBB/Negative/A-2	5
Metropolitan Edison Co.	BBB/Negative/A-2	5
Ohio Edison Co.	BBB/Negative/—	6
Cleveland Electric Illuminating Co.	BBB/Negative/—	6
Toledo Edison Co.	BBB/Negative/—	6
FirstEnergy Corp.	BBB/Negative/—	6
GPU Inc.	BBB/Negative/A-2	5
Southwestern Energy Co.	BBB/Negative/—	8
Duquesne Light Co.	BBB/Negative/A-2	4
DQE Inc.	BBB/Negative/A-2	5
Williams Gas Pipe Line Central	BBB/Negative/A-2	3
Transcontinental Gas Pipe Line Corp.	BBB/Negative/A-2	3
Texas Gas Transmission Corp.	BBB/Negative/A-2	4
The Williams Cos. Inc.	BBB/Negative/A-2	3
NiSource Inc.	BBB/Negative/A-2	4
Columbia Energy Group	BBB/Negative/—	4
Bay State Gas Co.	BBB/Negative/—	3
Northern Indiana Public Service Co.	BBB/Negative/—	5
SEMCO Energy Inc.	BBB/Negative/—	3
Reliant Resources Inc.	BBB/CW-Neg/A-2	7
Reliant Mid-Atlantic Holding LLC	BBB/CW-Neg/—	7
Orion Power Holdings Inc.	BBB/CW-Neg/—	7
Aquila Inc.	BBB/CW-Neg/A-2	6
Aquila Merchant Services Inc.	BBB/CW-Neg/—	9
Central Illinois Light Co.	BBB-/CW-Pos/—	4
CILCORP	BBB-/CW-Pos/—	4
Green Mountain Power Corp.	BBB-/Positive/—	7
El Paso Electric Co.	BBB-/Stable/—	6
Mirant Americas Generating Inc.	BBB-/Stable/—	7
Mirant Corp.	BBB-/Stable/A-3	7
Mirant Americas Energy Marketing	BBB-/Stable/—	8
Entergy Gulf States Inc.	BBB-/Stable/—	6
System Energy Resources Inc.	BBB-/Stable/—	7
Central Vermont Public Service Corp.	BBB-/Stable/—	6
Texas-New Mexico Power Co.	BBB-/Stable/—	5
Public Service Co. of New Mexico	BBB-/Stable/—	6
Puget Sound Energy Inc.	BBB-/CW-Dev/A-3	5
Washington Natural Gas Co.	BBB-/CW-Dev/A-3	5
Puget Sound Power & Light Co.	BBB-/CW-Dev/A-3	5
Puget Energy Inc.	BBB-/CW-Dev/A-3	5
Northern Natural Gas Co.	BBB-/CW-Dev/—	3
Southwest Gas Corp.	BBB-/Negative/—	4
Indianapolis Power & Light Co.	BBB-/Negative/—	4
IPALCO Enterprises Inc.	BBB-/Negative/—	4
Illinois Power Co.	BBB-/CW-Neg/A-2	6
Dynegy Holdings Inc.	BBB-/CW-Neg/A-3	6
Illinova Corp.	BBB-/CW-Neg/—	7
Dynegy Inc.	BBB-/CW-Neg/A-3	7
El Paso Energy Partners L.P.	BB+/Positive/—	6
Market Hub Partners Storage L.P.	BB+/Stable/—	7
Sonat Energy Services Co.	BB+/Stable/—	9
Western Gas Resources Inc.	BB+/Stable/—	7
Westar Energy Inc.	BB+/Negative/—	6
Avista Corp.	BB+/Negative/—	5
AmeriGas Partners L.P.	BB+/Negative/—	5
Tucson Electric Power Co.	BB/Stable/—	6
Southern California Edison Co.	BB/CW-Dev/—	8
*Consumers Energy Co.	BB/Negative/—	6
*CMS Panhandle Pipeline Cos.	BB/Negative/—	4
*CMS Energy Corp.	BB/Negative/—	6
Heating Oil Partners L.P.	B+/Stable/—	3
Sierra Pacific Power Co.	B+/CW-Neg/B	5
Nevada Power Co.	B+/CW-Neg/B	6
Sierra Pacific Resources	B+/CW-Neg/—	5
EOTT Energy Partners L.P.	B+/CW-Neg/—	8
Edison International	B-/Developing/—	8
Transwestern Pipeline Co.	CC/CW-Dev/—	5
Pacific Gas & Electric Co.	D/—/D	9
Enron Corp.	D/—/—	6
Azurix Corp.	D/—/—	4

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-__________

DIRECT TESTIMONY OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Kelly O. Norwood. I am employed as the Vice-President of Rates and Regulation by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. Please briefly describe your educational background and professional experience.

A. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in June 1981. Over the past 21 years I have spent approximately ten years in the Rates Department with involvement in cost of service, rate design and revenue requirements. I have spent approximately eleven years in the Energy Resources Department (power supply and natural gas supply) in a variety of roles with involvement in resource planning, system operations, resource analysis, negotiation of power contracts, and risk management. I was appointed Vice-President of Rates and Regulation in August 2001.

Q. What is the scope of your testimony in this proceeding?

A. I will summarize the Company's request to extend the existing 19.4% surcharge for an additional 12-month period. I will provide a brief overview of the Company's current financial situation and provide a status report on the Company's Idaho Power Cost Adjustment ("PCA") balance. My testimony will also explain the PCA deferrals for the period July 2001 though June 2002 and the conditions that caused the Company to incur the deferred power costs.

I am sponsoring Exhibit _____ (KON-1) through Exhibit _____ (KON-5) for identification, which were prepared under my direction.

Q. Would you please summarize the Company's request in this filing?

A. Yes. Through this filing, the Company is complying with the requirement from Order No. 28876 in Case No. AVU-E-01-11 to file a status report regarding PCA deferrals. Avista is requesting that the Commission approve recovery of PCA costs deferred through June 30, 2002, and grant continuation of the existing PCA surcharge for the 12-month period ending October 11, 2003. The Company is also requesting a modification to the deferral carrying charge interest rate from 4.0% to 6.0% as explained in the testimony of Mr. McKenzie. The higher interest rate would more accurately reflect the higher cost to finance these power cost deferrals over a multi-year period.

II. FINANCIAL SITUATION

Q. Would you please provide an overview of Avista's current financial situation?

A. Yes. Avista is continuing to take the steps necessary to improve the financial health of the Company following the impacts of the adverse hydroelectric and market price conditions experienced in 2000 and 2001. Despite the efforts by the Company, and the electric rate surcharges implemented in the fall of 2001 to begin recovering deferred power costs, the Company's credit ratings dropped below investment grade in October 2001, causing increased borrowing costs to the Company and ultimately to its customers. Over time, the added interest costs resulting from being below investment grade will continue as existing debt matures and must be refinanced. It is important for Avista to regain an investment grade credit rating as soon as possible to reduce these borrowing costs.

In order to improve its financial condition, the Company has scaled back and sold subsidiary businesses, sold one-half of the Coyote Springs II generating project currently under construction, and made significant cuts to its capital and operations and maintenance (O&M) costs. In 2002 hydroelectric generation conditions have returned to more normal levels and the Company's cash-flow situation has improved. In addition, the Company was able to renew its existing short-term line of credit on May 21, 2002, where the Company entered into a committed line of credit with various banks of $225.0 million. This new line of credit expires in May 2003.

In spite of these improvements, however, Avista's credit ratings remain below investment grade and the financial analysts continue to characterize the Company's outlook as negative. In Standard & Poor's July 22, 2002 listing of "U.S. Electric/Gas/Water Companies," attached as pages 1 through 3 of Exhibit __ (KON-1), Avista is ranked 304th out of 320 utilities rated by S&P. It is important for both the Company and our customers that Avista continue to improve its financial condition so that investment grade credit ratings can be restored. The continued recovery of deferred power costs through extension of the existing PCA surcharge is a critical component, as the Company continues to work toward an investment grade credit rating.

Q. What are Avista's current credit ratings?

A. Avista's credit ratings are presented in the following table:

	Standard & Poor's	Moody's	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB+
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB

III. SUMMARY OF DEFERRED POWER COSTS

Q. Please briefly describe the power cost deferrals during the period July 2001 through June 2002.

A. The deferrals for the period July 2001 through June 2002 totaled $48,442,371 for the Company's Idaho jurisdiction. Of that total, approximately $46 million occurred during the last six months of 2001 when the Company was still experiencing the costs associated with the record-low streamflow conditions and high wholesale market prices. The Company paid high prices for power to cover energy deficiencies caused primarily by the record-low streamflow conditions, and to protect the Company against the extremely high prices predicted for the summer of 2001. Deferrals for the first six months of 2002 have totaled only $2.1 million, as compared to the $46 million for the last six months of 2001. This reflects a return to near normal hydroelectric conditions, among other changes. A summary of the deferrals for the period is shown on Exhibit ____ (KON-2).

The largest contributors to the deferrals were purchased power expenses and thermal fuel expense. The increase in purchased power expenses resulted from the increased need for power purchases due primarily to record-low hydroelectric conditions and the high power prices. The increased thermal fuel expense is due primarily to higher natural gas prices and increased generation.

The table below shows a breakdown of the major components of the deferrals during the period. We have provided as workpapers the monthly deferral reports that detail the specific accounts and other costs that contributed to the deferrals during the period.

Major Components of PCA Deferrals
July 2001 - June 2002

Purchased Power	$39,034,724
Sales for Resale	-$8,393,600
Thermal Fuel Expense	$11,100,868
Leased Small Gen Costs	$3,830,643
Buy Back Expense	$2,169,263
Centralia O&M Credit	-$2,817,996
Retail Revenue Adjustment	$4,695,328
Potlatch Contract Change	-$1,365,540
Wood Power Amortization	$412,131
Other	-$223,450
Total Deferrals	$48,442,371

IV. CONDITIONS THAT CAUSED THE DEFERRED POWER COSTS

Q. Please briefly describe the hydroelectric generation conditions during the deferral period of July 2001 through June 2002.

A. Avista experienced streamflow conditions in 2001 that produced the lowest hydroelectric generation output in the 73 years for which records have been kept. Under normal water conditions, Avista would expect to generate 554 aMW from its hydroelectric resources (owned and contracted). In a critical water year, Avista would expect hydroelectric generation of approximately 150 aMW below normal. The hydroelectric generation for 2001 was 369 aMW, which is 185 aMW below the normal level of 554 aMW. This is well below what would be expected for even the worst year in the 73 years for which records have been kept. In the first half of 2002 hydroelectric conditions returned to near normal levels. As indicated earlier, deferrals for the last six months of 2001 totaled approximately $46 million, but were only $2.1 million for the first six months of 2002. Because of the greatly reduced hydroelectric generation in 2001, the Company was required to purchase power for the second half of 2001 at high wholesale market prices. These record-low hydroelectric generation conditions and the high wholesale market prices were explained in some detail in the Company's previous PCA surcharge filing in August 2001.

V. MITIGATING MEASURES TAKEN BY AVISTA

Q. Please explain Avista's efforts to mitigate the costs incurred by the Company during the deferral period.

A. The Company implemented a variety of measures all aimed at mitigating the Company's price exposure in the face of very low streamflow conditions and very high and volatile power prices in the forward market. The Company took a portfolio approach that included acquiring both demand-side and supply-side resources to cover its energy deficiencies.

A brief description of some of the measures taken by the Company to cover its deficiencies and mitigate increased costs is provided below. Additional details related to many of these measures are included in workpapers provided with this filing.

1. Communication of market conditions and conservation messages to customers.
The Company communicated the challenges facing the electric utility industry and Avista to its customers through bill inserts, advertisements in the local newspaper, radio and TV media beginning in December 2000. Many advertisements were run in several different media including direct mail, customer education programs, radio, TV, and print. In a mid-June 2001 survey, 87% of Avista customers recalled seeing Company advertising specifically about conservation, and 73% of those customers said they had taken some action to reduce energy use as a result of the advertising messages. There are no costs in the PCA deferral account associated with this measure. Additional information related to these efforts is provided in workpapers.

2. Escalation of energy efficiency efforts.
The Company accelerated its energy efficiency efforts. The programs targeted measures that offered retail customers immediate electric savings through proven efficiency technologies. Over 688,000 compact fluorescent lamps were distributed, 8,350 rooftop HVAC units were tuned, and 952 gas water heaters were installed. These programs, and

other efficiency measures, tripled the amount of energy savings the Company would otherwise achieve on an annual basis. The costs associated with these energy efficiency measures were charged to the DSM Tariff Rider account. There are no costs in the PCA deferral account associated with this measure.

3. Retail Buy-Back Programs.

The Company received approval from the Commission to implement three "buy-back" programs, including programs for industrial customers, irrigation customers, and all other customers. The buy-back programs were designed to provide benefits to the specific customers reducing their load, as well as all other customers of the Company. At the time the programs were put into place they represented a lower-cost means to serve load requirements than purchasing additional energy in the wholesale market. The IPUC approved the Company's request to terminate the all-customer program early, because it was no longer economic. Additional information related to the programs is included in the workpapers.

4. Filed for a modification of the air permit for the Rathdrum combustion turbines.

As the Company entered 2001, it could operate the two Rathdrum units a total of 6600 hours per unit per year. Because of the high electric market prices, the Company filed to extend the hours of operation for Rathdrum to 8424 hours per unit per year. Otherwise, Avista would have had to shut the units down once the operating hour limit was reached. During the first half of 2001, the Company proceeded to operate Rathdrum at full load in anticipation of receiving the permit modification. Running the units at full load avoided making additional expensive purchases from the wholesale market. The Company received the new permit in October 2001. There are no costs in the deferral account associated with the permit modification.

5. Purchased spare parts for Rathdrum to reduce down-time during maintenance.

Because of the increased operation of the Rathdrum turbines, it was necessary to schedule maintenance on the units in the spring of 2001. Under normal conditions, the Company would ship out key parts of one unit at a time to be reconditioned while other on-site maintenance was performed on the unit. The normal maintenance schedule would have been 12 to 14 weeks. Because of the high price of power, however, the Company located and purchased a spare set of parts to reduce the down-time for maintenance to only four weeks. The Company avoided additional high-priced purchases from the wholesale market during the weeks that maintenance would have otherwise occurred. There are no costs in the deferral account associated with this measure.

6. Gained permission for increased operation of Northeast Combustion Turbines.

Under the existing air emissions permit for the Northeast Turbines, the units are allowed to run approximately 500 hours per year. On the initiative of the Company, Avista was able to successfully negotiate agreements that granted permission to run the units for additional hours. The Company received permission to run the units for additional hours in August and September 2000, and beginning again February 21, 2001 and continuing through the Governor's Energy Supply Alert. Additional information is provided in the workpapers.

8. Delayed delivery of BPA exchange obligation under the WNP-3 agreement.
Under a provision of the WNP-3 Agreement, the Bonneville Power Administration (BPA) called on over 200,000 MWh of energy for the months of January - April and June 2001, to be provided by Avista at a price based on the operating costs of the Northeast Combustion Turbines. Through negotiations initiated by Avista, BPA agreed to delay the delivery of energy until the fourth quarter of 2001, and relieve Avista of further obligations under the Settlement Agreement for the 2000/2001 operating year. At the time of the transaction, the estimated benefits to Avista's customers by delaying the deliveries was \$6.1 million. Additional information is provided in the workpapers.

9. Inter-Month Exchanges: Purchase and sale.
In April 2001 Avista was near load/resource balance for the third quarter of 2001, but was deficient energy in July and surplus in September. On April 18, 2001, the Company entered into an exchange transaction, where Avista purchased 50 aMW from a third party for July 2001 at \$490/MWH, and sold 50 aMW to the same party for September at \$480/MWH. The difference in price was caused by the difference in market prices for the two months. The simultaneous sale of energy in September preserved, or hedged, the value of the surplus, as compared to a simple purchase of energy in July to cover the deficiency.

10. Inter-Month Exchange: Exchange of energy.
On April 12, 2001, the Company entered into an exchange transaction, where Avista agreed to deliver 60 aMW to a third party in September 2001, in exchange for receipt of 50 aMW from the same party in July 2001. Avista was energy deficient in July, but surplus in September. The market price was higher in July than in September, which accounted for the difference in the energy deliveries. The agreement to exchange energy in this manner, preserved, or hedged, the value of the surplus in September, as compared to a simple purchase of energy in July at a cost of approximately \$490/MWH to cover the deficiency.

11. Leased temporary generation resources (30 MW of capability).
The Company selected a variety of generation projects that could be installed quickly and run on natural gas or diesel fuel. The Company leased 20 diesel units (20 megawatts) and located them at Avista's Devil's Gap substation, and also leased six units (10 megawatts) that run on a combination of natural gas and diesel, and located them at Avista's Kettle Falls generating station site. These units were dispatchable and did not have to run if purchasing energy in the short-term market was less costly. The decision to pursue these projects allowed the Company to avoid additional high-cost purchases of energy from the short-term wholesale market, and represented a "call option" to the Company for the

amount of energy available from the units.

12. Purchased additional small generation resources.
In addition to the leased projects, the Company acquired generation sites and equipment, and initiated permitting on new generation to be owned by Avista. Projects were selected that could be installed quickly. The Company completed the Boulder Park project that includes six gas-fired reciprocating engines for a total of 25 MW. The Company also initiated plans to install a 23 MW combustion turbine at Othello, Washington and two gas-fired reciprocating engines at the Spokane Industrial Park (SIP). Subsequent to the drop in the electric power market in the second half of 2001, the Othello project was cancelled. The SIP Project was also cancelled, however the Company is currently evaluating the possible installation of the two units at the Boulder Park site. The decision to pursue these projects allowed the Company to avoid additional high-cost purchases of energy from the short-term wholesale market, and represented a "call option" to the Company for the amount of energy available from the units.

As is evident from the list above, the Company implemented a wide variety of measures, involving both demand-side and supply-side resources, to cover its energy deficiencies caused primarily by the record-low streamflow conditions, and to mitigate the costs associated with the high and volatile power prices. Again, many of these mitigating measures, among others, were explained in the Company's previous PCA surcharge filing in August 2001.

VI. POWER PURCHASES

Q. How did power purchases contribute to the deferrals during the period?

A. The cost of purchasing power for the period greatly exceeded the normalized level of power purchase expense. As indicated earlier, this was due primarily to the record-low streamflow conditions and the extremely high wholesale market prices. Higher power purchase expenses account for $39 million, or 81%, of deferrals during the period.

Q. Would you please describe the specific short-term purchases made by the Company?

A. Yes. The Company entered into a mix of short-term wholesale transactions ranging in terms from one-hour to one-year to balance the Company's resources with its load requirements. The Company layered in purchases over time, including heavy-load, light-load, and flat products, as needed to meet the specific requirements of the Company's system. The Company also entered into various inter-month exchanges (see mitigating measures explained earlier) to balance out its loads and resources across months.

In early 2001, as the Company was looking forward to the summer and fall of 2001, power prices were high and indications were that they would get even higher. The Company choose to purchase sufficient power ahead of time to meet load obligations rather than risk going into the summer in a short position with the possibility of paying potentially much higher prices or being in a position of not being able to serve loads.

Q. Why did the Company make purchases to cover summer deficiencies?

A. As stated earlier, indications were that the electricity shortage situation was only going to get worse as the hottest summer weather arrived. During the spring months of 2001, Avista's hydroelectric generation forecasts continued to decline significantly, forward market prices continued to climb, California warned of a large number of potential rolling black-outs for the upcoming summer, and federal policy-makers in Washington D.C. were persistent that price caps would not be imposed as a solution to the high market prices in the West.

Given these conditions, the Company chose to cover its deficiencies in the summer months in advance rather than risk the potential for even higher prices as the summer drew nearer. As an example, Northwest market prices in December 2000 for daily purchases traded as high as $5,000/MWh, as shown in an excerpt from the December 11, 2000 Megawatt Daily, attached as page 1 of Exhibit ____ (KON-3). Page 2 of the Exhibit includes an excerpt from the same report and states that "balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day." Pages 3 - 5 of Exhibit ____ (KON-3) include references to statements by federal policymakers, as late as June 14, 2001, related to their refusal to implement price caps in the West to mitigate wholesale market prices.

Thus, in light of the high volatility of market prices, the warnings of impending summer rolling blackouts in California, and the persistent refusal of federal policy-makers to mitigate market prices, the Company believed it was necessary to cover the energy deficiencies in the spring and summer months of 2001 caused by the continued deterioration of hydroelectric generation conditions.

In reviewing the Company's previous PCA surcharge filing of August 2001, the Commission Staff requested, and Avista provided, copies of all firm contractual commitments for electricity purchases for the period July through December 2001.

VII. THERMAL FUEL COSTS

Q. What is included in thermal fuel costs in the PCA deferral?

A. Thermal fuel costs consist of three primary components, including the costs of coal, wood fuel and natural gas. Coal and wood fuel costs are included in FERC Account 501. Natural gas fuel that is consumed for generation is included in Account 547, CT Fuel. The purchase cost of natural gas fuel not consumed for generation but resold is reflected in Account 557, and the revenue from the sale of the gas is included in Account 446. The decision to burn natural gas purchased for generation or to sell the gas is generally based on a simple comparison of the cost of the gas-fired generation, versus the sale of the natural gas together with a purchase of an equivalent amount of electricity from the wholesale market. If it is less expensive to sell the gas and buy the electricity than to generate with the gas, then the gas would be sold and electricity would be purchased.

Q. Please provide an overview of what the Company considers in purchasing natural gas for its combustion turbines.

A. As part of optimizing the use of its natural gas combustion turbines, the Company may choose to secure fixed price gas supply in forward months depending on the spread ("implied heat rate[1]") between the price of natural gas and the price of electric power in those forward months. Two examples are provided below for the Rathdrum turbines. For simplicity the non-fuel variable costs of operating the turbines is ignored.

1) The heat rate of the Company's two Rathdrum combustion turbines is approximately 12,000 BTU/kWh. If the forward price for electricity is $200/MWh and the natural gas price is $5.00/MMBTU, this represents an implied heat rate of 40,000BTU/kWh. The implied heat rate is well above the 12,000 BTU/kWh heat rate. Therefore, in this example, the Company is better off to purchase gas at $5.00/MMBTU for the Rathdrum combustion turbine at the 12,000 BTU/kWh heat rate, and to generate electricity at $60.00/kWh, compared to purchasing power in the market for $200/MWh.

2) If the forward price for power is $30/MWh and the price for natural gas for the same period is $3.10/MMBTU, this represents an implied heat rate of 9,677 BTU/kWh. This implied heat rate is below the 12,000 BTU/kWh heat rate of the Rathdrum combustion turbine. Therefore, it is more economic to purchase electric power for $30/MWh than to purchase natural gas for the Rathdrum turbine. The cost to generate electricity would be $37.20/MWh at a natural gas price of $3.10/MMBTU.

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[1] "Implied Heat Rate" identifies the marginal turbine that is supported by the markets for natural gas and electricity. The calculation of implied heat rate is performed by dividing the electricity price by the natural gas price and multiplying by 1000. For example, where the Mid-C price is $30 per MWh and the price of natural gas is $3.00 per dekatherm, the marginal operating unit would have a heat rate of 10,000 British thermal units per kilowatt-hour (Btu/kWh).

Prior to year 2000, the forward implied heat rate between electric power prices and natural gas prices was not often high enough to warrant purchasing natural gas for future electric power generation given the 12,000 BTU/kWh heat rate of the Rathdrum plant. To the extent that Company did not purchase natural gas in advance, it would then later, on a daily basis, evaluate whether to run the combustion turbines depending on the natural gas and electric price spread for that day.

In the period May 2000 through August 2001, the implied heat rate between natural gas and electric prices for a rolling one-year forward period, for example, (using monthly prices) averaged 28,229 BTU/kWh. Because this latter period implied heat rate was substantially greater than the 12,000 BTU/kWh, the Company acquired some forward natural gas for fueling the Rathdrum, Northeast, Boulder Park and Coyote Springs generation projects.

Q. Please explain these natural gas purchases?

A. In March 2001 the Company contracted for firm natural gas deliveries, including firm transportation, on the PG&E GTN line from the Canadian border to the California-Oregon border at Malin, for varying volumes for the period November 2001 through October 2004. The natural gas could be delivered at several points on the interstate natural gas pipeline between the Canadian border and Malin. The Malin delivery point is an active marketing point where the Company can sell natural gas when the generating units are not running. The combination of these factors gives flexibility in the use of the gas. The term of one transaction for 28,000 Dth/day is November 1, 2001 through October 31, 2004. The term of the second transaction for 20,000 Dth/day is June 1, 2002 through October 31, 2003. During the period November 1, 2001 through May 31, 2002, gas supplies were available for use either at peaking projects, such as the

Rathdrum or Northeast CT projects, or for use as CSII test gas. Once CSII began operation, it would have the best heat rate of the natural gas generation available to the Company, and gas supplies would be most efficiently used at that project.

In April and May 2001, the Company hedged, or fixed the price, for varying natural gas volumes for the period November 2001 through October 2004. The hedges fixed the price on approximately 29% of the total natural gas that would be necessary to run the Company's gas-fired projects. The hedges were performed through fixed-for-floating price transactions. The weighted average hedge prices, including index adder, were: $5.99/Dth for 20,000 Dth/day for the June 1, 2002 through October 31, 2003 period; and $6.45/Dth for 20,000 Dth/day the November 1, 2001 through October 31, 2004 period. The calculated variable cost of generation, resulting from using the natural gas in generation units with different heat rates, was compared to the forward electric power prices available in the same forward period. In each case, hedging the price of natural gas was less expensive than purchasing power at prices available in the forward market.

The hedges allowed the Company to fix varying portions of the natural gas supply that would be necessary to run the Rathdrum, Northeast CT, Boulder Park, and CSII natural gas fired generation cost at prices lower than the comparable electric power prices available at the time. Additional information regarding these natural gas purchases and hedges is provided in the workpapers.

VIII. 2001 SMALL GENERATION RESOURCES

Q. Please explain the acquisition of small generation resources by the Company.

A. As explained earlier the Company undertook a variety of measures to mitigate the increased costs to the Company from the record-low hydroelectric generation conditions and the high wholesale market prices. The installation of small generation projects distributed on Avista's electric grid is just one component of the portfolio of resources that the Company chose to cover load requirements, including load variations, unscheduled generation outages, variability in hydroelectric generation, etc., and to mitigate costs. The Company selected 86 MW of small generation projects that could be installed quickly, would include the necessary pollution control equipment, and could operate using natural gas, diesel fuel, or a combination of those fuel types. Those projects consisted of 30 MW of temporary leased units, that could be easily removed at a later time, and 56 MW of Company-owned units. In addition, the Company completed one contract with a third party to purchase output from a 3 MW small generation project. The following table summarizes the above projects:

Site	MW Output	Type	Fuel	Dispatchable	Ownership	Status
Boulder Park	25	Reciprocating Engine	Natural Gas	Yes	Avista	On-line.
Spokane Industrial Park	8	Reciprocating Engine	Natural Gas	Yes	Avista	SIP project is cancelled. Assessing installation of units at Boulder Park.
Kettle Falls	10	Reciprocating Engine	Bi-fuel: Natural Gas & Diesel	Yes	Leased	Temporary air permit expired 7-25-02.

Devil's Gap	20	Reciprocating Engine	Diesel	Yes	Leased	Cancelled due to decline in energy prices.
Othello	23	Combustion Turbine	Diesel	Yes	Avista	Cancelled due to decline in energy prices.
Small Butte Power	3	Reciprocating Engine	Diesel	No	Third-party	No power generated due to decline in energy prices

With the decline in wholesale power prices in the second half of 2001, two of the projects (Othello and Devil's Gap), totaling 43 MW were cancelled. The SIP project was also cancelled, however the Company is currently evaluating the possible installation of these units at the Boulder Park site.

The acquisition of these small generation projects, with the exception of the Small Butte Power Project, were also explained in the Company's previous PCA surcharge filing in August 2001.

Q. Please explain why the new small generation resources were necessary.

A. As explained earlier, in the first quarter of 2001 the Company began to experience the worst year for hydroelectric generation in 73 years of recorded history. In February 2001, as the Company was evaluating alternatives to purchasing high-priced replacement energy to cover the reductions in its hydroelectric generation, it began to consider the alternative of small generation projects that might be third-party owned, Company owned, or leased.

Small generation was considered as one component of a portfolio of resource options to fill the Company's supply deficiencies because the units could be brought on-line quickly, were dispatchable, had fixed and variable components to their cost structure, and were lower cost than the energy market purchases. Other utilities throughout the northwest were putting small generation projects in place to avoid purchasing power at high prices, to cover lower hydroelectric generation conditions, and to meet load obligations reliably under a variety of conditions. Given the high power market prices and the high volatility of power prices, there was a need to plan not only to cover average load obligations, but also to have some degree of coverage for load variability, hydroelectric generation variability, and unplanned outages of generation units. In the July 2001 publication of "NWPPC News," (see workpapers) the Power Planning Council indicated that there were approximately 68 temporary generation projects that were either operating or planned.

Q. Why were the specific small generation resources selected?

A. The small generation projects selected were shown to be cost-effective on a total cost basis when compared to market purchases at the time of the decisions to proceed. The initial economic evaluations for the Kettle Falls Bi-Fuel and Devil's Gap projects are provided as pages 1 through 8 of Exhibit __ (KON-4). The Kettle Falls Bi-Fuel and Devil's Gap projects were lease projects. The year-ahead energy market prices were high and initial analysis showed these units would operate with positive total economics in almost all months of their lease. The economic analysis performed showed that the units would operate at a 90% and 92% plant factor respectively, and the analyses showed positive benefits for these projects over their lease terms.

These generation projects also provided the additional benefit of dispatchability. Because of the fixed and variable cost components of these projects, they are similar to purchasing a "call option." A call option is essentially like buying insurance in that one pays a premium for the right to receive a benefit in the future under certain conditions. In this case, that condition is the

Company's right to generate at the incremental or variable cost of fuel, when the market price for electricity is higher than that cost of fuel. As an example, the analysis on Page 3 of Exhibit ____ (KON-4) shows that the fixed cost to generate with the Kettle Falls Bi-Fuel units was projected to be $53/MWh, compared with the cost to purchase power from the wholesale market at $265/MWh for the same time period.

Q. How did the Company incorporate a range of views about an uncertain future in its decision to acquire small generation?

A. The Company selected small generation resources as a portion of its overall portfolio approach to dealing with the record-low hydroelectric generation, and unprecedented high forward electric prices. Selecting these resources allowed the Company to secure a portion of its needed supply to serve average expected load and to be prepared to serve load under variable load conditions. The dispatchable nature of these resources allowed more adaptability to changes in energy prices than a fixed price energy purchase from the wholesale market. <u>Only the cost of the equipment or lease was fixed. The variable costs of the projects, including variable fuel costs, would be incurred only when the power market prices were higher. Acquiring this type of resource allowed the Company to avoid a major portion of the cost of the power if the market price later declined, which it ultimately did. Alternatively, if the Company had purchased an equivalent amount of power from the wholesale market, the full cost of that purchase would be fixed even if the market declined.</u> Therefore, this portion of the Company's portfolio of resources acquired to fill the resource gap allowed for more flexibility and lower comparable cost. This resulted in lower costs in the PCA deferral account, and ultimately to customers, than the alternative to purchase firm power from the high-priced wholesale market.

Q. Were the small generation projects re-evaluated as power market conditions changed?

A. Yes. On June 19, 2001 a review of the small generation projects was conducted. Attached as pages 9 and 10 of Exhibit __ (KON-4) are tables summarizing the results of the updated modeling. Also included in the table on page 9 are summaries of the original economic analyses, at the time projects were selected, as well as analyses on June 4, 2001 and June 11, 2001.

The June 19th study, for example, showed that the costs to complete the Kettle Falls Bi-Fuel and the Devil's Gap projects were either below or approximately equal to the premium for the one-year call option. Therefore, those projects were continued. By September 2001, projections showed that the Devil's Gap Project was no longer economic to operate. Given that projection, and because of the Company's tight cash situation, the Company decided to negotiate termination with the equipment lessor. The Company and the lessor of the equipment subsequently met and agreed on a settlement cost of $7.1 million which was a $3.4 million savings compared to following the terms of the original lease to conclusion. Therefore, in this case, by selecting the small generation project instead of purchasing power from the wholesale market, the Company was able to not only avoid the variable costs of the amount of power the generator would have produced, but was also able to avoid part of the fixed cost of the power.

IX. POTLATCH CONTRACT CHANGE

Q. Please briefly summarize the change in the Potlatch contract.

A. A ten-year purchase and sale agreement related to the Potlatch facilities in Lewiston, Idaho expired at the end of December 2001. The regulatory treatment associated with that contract allowed for a jurisdictional sharing (Idaho and Washington) of the sales revenue to match with the long-term PURPA purchase expense and the cost of market-priced interruptible energy Avista sold to Potlatch. The costs included in the Company's last general rate case reflect this jurisdictional sharing and the authorized production-transmission ratio was calculated excluding the Idaho usage associated with the allocated revenue. Beginning in January 2002 Potlatch has self-generated the equivalent of the prior long-term PURPA purchase and receives service at Schedule 25 rates for the remainder of their load.

Q. In the PCA calculations, beginning in January 2002 the cost of 25 aMw of power is removed from actual system costs and directly assigned to the Idaho Jurisdiction. Please explain the purpose of this direct assignment entry in the PCA deferrals.

A. The direct assignment of the cost of 25 aMW reflects the elimination of the market priced interruptible energy in the prior contract that is now firm Idaho Schedule 25 usage not accounted for in the production transmission ratio.

The Potlatch direct assignment entries remove the cost of 25 aMW from actual system costs each month and directly assigns the same cost directly to the Idaho jurisdiction. This is necessary because of the expiration of the long-term sale and power purchase contract with Potlatch on December 31, 2001, and the current arrangement with Potlatch to serve their net load requirements at their Lewiston facilities. The direct assignment of the cost of 25 aMw serves the same purpose as the prior allocation of Potlatch revenue between the Idaho and Washington jurisdictions in the previous 10-year Potlatch/Avista Agreement that ended December 31, 2001.

That is, to mitigate the impact on the Washington jurisdiction customers related to the costs to serve the Potlatch load.

Q. What is the net impact of the change in arrangements with Potlatch on the PCA deferrals since the expiration of the prior purchase and sale agreement on December 31, 2001?

A. The direct assignment credit entries together with the retail revenue adjustment for Potlatch, has reduced the Idaho PCA surcharge deferrals by $1,365,540 from January to June 2002. Exhibit ____ (KON-5) shows how this value is derived.

Q. How is the revenue associated with Potlatch reflected in the PCA?

A. Potlatch revenue is included in the retail revenue credit and calculated separately from the retail revenue adjustment based on the change in load. Until December 2001, the Potlatch revenue adjustment was calculated by comparing the Idaho share of actual Potlatch allocated and direct revenue to the Idaho share of authorized Potlatch revenue. Beginning in January 2002, total Potlatch actual base revenue (exclusive of PCA surcharge, DSM rider, and Centralia Gain credit) is compared to the Idaho share of the authorized Potlatch revenue.

X. SUMMARY

Q. Would you please summarize your testimony?

A. Yes. The majority of the PCA deferrals for the period July 2001 through June 2002 occurred during the last half of 2001, and were driven primarily by the continuation of record-low hydroelectric generation and purchases of high-priced power to cover the resulting energy deficiencies. Deferrals for the last half of 2001 totaled approximately $46 million, compared with the deferrals in the first half of 2002 of approximately $2 million.

The Company implemented a wide variety of measures, involving both demand-side and supply-side resources, to cover its energy deficiencies and to mitigate the costs associated with continuing to serve its load requirements. The hydroelectric conditions experienced by the Company in 2001, the extraordinarily high market prices that occurred during that time, and many of the mitigating measures taken by the Company were previously explained in the Company's PCA surcharge filing in August 2001.

The continued recovery of deferred power costs through extension of the existing PCA surcharge is a critical component, as the Company continues to work toward regaining an investment grade credit rating.

The Company requests that the Commission approve recovery of PCA costs deferred through June 30, 2002, and grant continuation of the existing PCA surcharge for the12-month period ending October 11, 2003. Additionally, the Company requests that the carrying charge interest rate on the deferral balance be increased from 4.0% to 6.0%, as explained in Mr. McKenzie's testimony.

Q. Does that conclude your pre-filed direct testimony?

A. Yes it does.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (KON-1) OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

The following list contains Standard & Poor's Ratings, Outlooks, and Business Profiles for utilities. This list, dated July 18, 2002, reflects the most current ratings, rankings, and outlooks. It is arranged by corporate credit rating categories. Within corporate credit rating categories, issuers are grouped by Outlooks; and within Outlook categories, issuers are listed by RELATIVE STRENGTH, with the first being the strongest, and the last being the weakest.

A Standard & Poor's rating Outlook assesses the potential direction of an issuer's long-term debt rating over the intermediate to longer term. In determining a rating Outlook, consideration is given to any changes in the economic and/or fundamental business conditions. An Outlook is not necessarily a precursor of a rating change or future CreditWatch action. "Positive" indicates that a rating may be raised; "Negative" means a rating may be lowered; "Stable" indicates that ratings are not likely to change; and "Developing" means ratings may be raised or lowered. N.M. means not meaningful.

Utility business profiles are categorized from 1 (strong) to 10 (weak). In order to determine a utility's business profile, Standard & Poor's analyzes the following qualitative business or operating characteristics typical of a utility: markets and service area economy; competitive position; fuel and power supply; operations; asset concentration; regulation; and management. Telecommunications companies have not been assigned business profiles. Issuer credit ratings, shown as long-term rating/outlook or CreditWatch/short-term rating, are local and foreign currency unless otherwise noted. A dash '—' indicates not rated. An asterisk '*' indicates that the utility was reviewed this week and its ranking position was updated.

U.S. Electric/Gas/Water Companies

Company	Corporate Credit Rating	Bus. Prof.
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Baton Rouge Water Works Co. (The)	AA/Stable/—	2
Madison Gas & Electric Co.	AA/Negative/A-1+	5
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
California Water Service Co.	AA-/Stable/—	3
Wisconsin Public Service Corp.	AA-/Stable/A-1	4
Peoples Gas Light & Coke Co.	AA-/Negative/A-1+	3
North Shore Gas Co.	AA-/Negative/A-1+	3
Elizabethtown Water Co.	AA-/Negative/—	3
Elizabethtown Corp.	AA-/Negative/—	4
Southern California Water Co.	A+/Stable/—	3
Southern California Gas Co.	A+/Stable/A-1	2
San Diego Gas & Electric Co.	A+/Stable/A-1	5
American States Water Co.	A+/Stable/—	3
Philadelphia Suburban Water Co.	A+/Stable/—	2
Consolidated Edison Co. of New York Inc.	A+/Stable/A-1	3
Consolidated Edison Inc.	A+/Stable/A-1	3
Orange and Rockland Utilities Inc.	A+/Stable/A-1	3
Rockland Electric Co.	A+/Stable/—	4
KeySpan Energy Delivery New York	A+/Stable/—	2
KeySpan Energy Delivery Long Island	A+/Stable/—	2
Laclede Gas Co.	A+/Stable/A-1	3
Laclede Group Inc.	A+/Stable/—	3
Otter Tail Power Co.	A+/Stable/A-1	6
WPS Resources Corp.	A+/Stable/A-1+	5
Questar Gas Co.	A+/Negative/—	2
Questar Pipeline Co.	A+/Negative/—	3
Peoples Energy Corp.	A+/Negative/A-1	4
Union Electric Co.	A+/CW-Neg/A-1	4
Central Illinois Public Service Co.	A+/CW-Neg/A-1	3
Ameren Corp.	A+/CW-Neg/A-1	5
*Duke Energy Corp.	A+/CW-Neg/A-1	5
*Duke Capital Corp.	A+/CW-Neg/A-1	6
*Texas Eastern Transmission L.P.	A+/CW-Neg/—	4
*PanEnergy Corp.	A+/CW-Neg/—	4
New Jersey-American Water Co.	A/CW-Pos/—	3
Central Hudson Gas & Electric Co.	A/Positive/—	3
New Jersey Natural Gas Co.	A/Positive/A-1	2
Aquarion Co.	A/Stable/—	3
BHC Co.	A/Stable/—	2
Middlesex Water Co.	A/Stable/—	3
Colonial Pipeline Co.	A/Stable/A-1	3
Montana-Dakota Utilities Co.	A/Stable/—	4
MDU Resources Group Inc.	A/Stable/A-1	5
Piedmont Natural Gas Co. Inc.	A/Stable/—	3
ONEOK Inc.	A/Stable/A-1	5
Boston Gas Co.	A/Stable/—	3
Colonial Gas Co.	A/Stable/—	3
Massachusetts Electric Co.	A/Stable/A-1	3
Narragansett Electric Co.	A/Stable/A-1	3
New England Power Co.	A/Stable/A-1	3
Niagara Mohawk Power Corp.	A/Stable/—	4
National Grid USA	A/Stable/A-1	3
NSTAR	A/Stable/A-1	3
Boston Edison Co.	A/Stable/A-1	3
Commonwealth Electric Co.	A/Stable/—	3
NSTAR Gas Co.	A/Stable/—	3
Cambridge Electric Light Co.	A/Stable/—	3
Buckeye Partners L.P.	A/Stable/—	4
KeySpan Generation LLC	A/Stable/—	4
KeySpan Corp.	A/Stable/A-1	3
Wisconsin Gas Co.	A/Stable/A-1	3
Wisconsin Electric Power Co.	A/Stable/A-1	4
Wisconsin Power & Light Co.	A/Stable/A-1	4
Virginia Electric & Power Co.	A/Stable/A-1	4
MidAmerican Energy Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/—	4
Georgia Power Co.	A/Stable/A-1	4
Savannah Electric & Power Co.	A/Stable/—	4
Southern Co.	A/Stable/A-1	4
Equitable Resources Inc.	A/Stable/A-1	5
Atlantic City Sewerage Co.	A/Stable/—	3
Beckley Water Co.	A/Stable/—	4
Public Service Co. of North Carolina Inc.	A/Negative/A-1	3
South Carolina Electric & Gas Co.	A/Negative/A-1	4
SCANA Corp.	A/Negative/—	4
Florida Power & Light Co.	A/CW-Neg/A-1	4
FPL Group Inc.	A/CW-Neg/—	6
FPL Group Capital	A/CW-Neg/A-1	8
Northwest Natural Gas Co.	A/CW-Neg/A-1	3
IDACORP Inc.	A-/Positive/A-2	5
Idaho Power Co.	A-/Positive/A-1	4
United Water New Jersey	A-/Stable/—	3
United Water Works	A-/Stable/—	3
NOVA Gas Transmission Ltd.	A-/Stable/—	2
TransCanada Pipelines Ltd.	A-/Stable/—	2
Atlanta Gas Light	A-/Stable/—	2
Alabama Gas Corp.	A-/Stable/—	2
Energen Corp.	A-/Stable/—	6
AGL Resources Inc.	A-/Stable/—	3
American Transmission Co.	A-/Stable/A-2	2
Interstate Power & Light Co.	A-/Stable/A-2	5

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Exhibit No.___ (KON-1)
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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Alliant Energy Corp.	A-/Stable/A-2	5
Alliant Energy Resources Inc.	A-/Stable/A-2	8
PG&E Gas Transmission-Northwest	A-/Stable/A-2	2
PPL Electric Utilities Corp.	A-/Stable/A-2	4
Baltimore Gas & Electric Co.	A-/Stable/A-1	3
Atmos Energy Corp.	A-/Stable/A-2	4
Kinder Morgan Energy Partners L.P.	A-/Stable/A-2	4
Indiana Gas Co. Inc.	A-/Stable/A-2	2
Southern Indiana Gas & Electric Co.	A-/Stable/—	5
Vectren Energy Delivery of Ohio	A-/Stable/—	4
Vectren Utility Holdings	A-/Stable/A-2	4
Vectren Corp.	A-/Stable/—	4
PECO Energy Co.	A-/Stable/A-2	4
Commonwealth Edison Co.	A-/Stable/A-2	4
Exelon Generation Co.	A-/Stable/—	8
Exelon Corp.	A-/Stable/A-2	6
Sempra Energy	A-/Stable/A-1	4
Wisconsin Energy Corp.	A-/Stable/A-2	5
Constellation Energy Group Inc.	A-/Stable/A-1	6
Delmarva Power & Light Co.	A-/Stable/A-2	3
PacifiCorp	A-/Negative/A-1	4
Oklahoma Gas & Electric Co.	A-/Negative/—	4
OGE Energy Corp.	A-/Negative/A-2	5
Enogex Inc.	A-/Negative/—	6
Northern Border Pipeline Co.	A-/Negative/—	3
Northern Border Partners L.P.	A-/Negative/—	3
National Fuel Gas Co.	A-/Negative/A-2	5
Tampa Electric Co.	A-/Negative/A-2	4
TECO Energy Inc.	A-/Negative/A-2	5
Teco Finance Inc.	A-/Negative/—	8
UGI Utilities Inc.	A-/Negative/—	4
Duke Energy Trading and Marketing LLC	A-/CW-Neg/—	8
Kern River Gas Transmission Co.	A-/CW-Neg/—	4
Louisville Gas & Electric Co.	BBB+/CW-Pos/A-2	4
Kentucky Utilities Co.	BBB+/CW-Pos/A-2	4
AmerenEnergy Generating Co.	BBB+/CW-Pos/—	7
LG&E Energy Corp.	BBB+/CW-Pos/—	6
LG&E Capital Corp.	BBB+/CW-Pos/A-2	8
South Jersey Gas Co.	BBB+/Stable/—	3
Reliant Energy Inc.	BBB+/Stable/A-2	3
Reliant Energy Resources Corp.	BBB+/Stable/A-2	3
El Paso Natural Gas Co.	BBB+/Stable/A-2	4
Tennessee Gas Pipeline Co.	BBB+/Stable/A-2	4
ANR Pipeline Co.	BBB+/Stable/—	4
Pepco Holdings Inc.	BBB+/Stable/A-2	4
Colorado Interstate Gas Co.	BBB+/Stable/—	3
Coastal Corp.	BBB+/Stable/—	6
Southern Natural Gas Co.	BBB+/Stable/—	4
El Paso Corp.	BBB+/Stable/A-2	6
El Paso Tennessee Pipeline Co.	BBB+/Stable/—	4
Cascade Natural Gas Corp.	BBB+/Stable/—	3
NorthWestern Corp.	BBB+/Stable/—	5
Connecticut Light & Power Co.	BBB+/Stable/—	4
Western Massachusetts Electric Co.	BBB+/Stable/—	4
Public Service Co. of New Hampshire	BBB+/Stable/—	5
Northeast Utilities	BBB+/Stable/—	5
Consolidated Natural Gas Co.	BBB+/Stable/A-2	5
Dominion Resources Inc.	BBB+/Stable/A-2	5
Northwestern Energy LLC	BBB+/Stable/A-2	4
Arizona Public Service Co.	BBB+/Stable/A-2	3
Maui Electric Co. Ltd.	BBB+/Stable/A-2	6
Hawaiian Electric Light Company	BBB+/Stable/A-2	6
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2	6
Central Power & Light Co.	BBB+/Stable/—	2
Appalachian Power Co.	BBB+/Stable/—	3
Columbus Southern Power Co.	BBB+/Stable/—	2
Indiana Michigan Power Co.	BBB+/Stable/—	4
Kentucky Power Co.	BBB+/Stable/—	3
Ohio Power Co.	BBB+/Stable/—	2
Public Service Co. of Oklahoma	BBB+/Stable/—	3
Southwestern Electric Power Co.	BBB+/Stable/—	3
West Texas Utilities Co.	BBB+/Stable/—	2
AEP Resources Inc.	BBB+/Stable/—	7
American Electric Power Co. Inc.	BBB+/Stable/A-2	5
West Penn Power Co.	BBB+/Stable/A-1	2
Potomac Edison Co.	BBB+/Stable/A-1	2
Monongahela Power Co.	BBB+/Stable/A-1	2
Allegheny Energy Inc.	BBB+/Stable/A-1	5
Allegheny Generating Co.	BBB+/Stable/A-2	7
Allegheny Energy Supply Co. LLC	BBB+/Stable/A-2	7
Detroit Edison Co.	BBB+/Stable/A-2	6
MCN Energy Enterprises Inc.	BBB+/Stable/A-2	8
DTE Enterprises	BBB+/Stable/—	6
DTE Energy Co.	BBB+/Stable/A-2	6
Cinergy Corp.	BBB+/Stable/A-2	5
Cincinnati Gas & Electric Co.	BBB+/Stable/—	4
PSI Energy Inc.	BBB+/Stable—	4
Union Light Heat & Power Co.	BBB+/Stable/—	4
Cleco Utility Group Inc.	BBB+/Stable/A-2	5
Cleco Corp.	BBB+/Stable/A-2	6
Potomac Electric Power Co.	BBB+/Stable/A-2	3
Conectiv	BBB+/Stable /A-2	4
Atlantic City Electric Co.	BBB+/Stable/A-2	3
Allete Inc.	BBB+/Stable/A-2	7
Southern Union Co.	BBB+/Stable/—	3
Providence Gas Co.	BBB+/Stable/—	3
Valley Gas Co.	BBB+/Stable/—	4
Valley Resources Inc.	BBB+/Stable/—	5
PG&E Energy Trading Holdings Co.	BBB+/Stable/—	8
Northwest Pipeline Co.	BBB+/Stable/A-2	3
TXU U.S. Holdings	BBB+/Stable/A-2	5
TXU Electric Delivery Co.	BBB+/Stable/A-2	5
TXU Energy Co.	BBB+/Stable/A-2	5
TXU Corp.	BBB+/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Negative/—	4
Midwest Independent Transmission System Operator Inc.	BBB+/Negative/—	3
Florida Power Corp.	BBB+/Negative/A-2	4
Carolina Power & Light Co	BBB+/Negative/A-2	5
Florida Progress Corp.	BBB+/Negative/A-2	5
Progress Energy Inc.	BBB+/Negative/A-2	5
Connecticut Natural Gas Corp.	BBB+/Negative/—	3
Southern Connecticut Gas Co.	BBB+/Negative/—	3
Central Maine Power Co.	BBB+/Negative/A-2	3
New York State Electric & Gas Corp.	BBB+/Negative/A-2	4
Energy East Corp.	BBB+/Negative/—	3
Rochester Gas & Electric Corp.	BBB+/Negative/—	5
RGS Energy Group Inc.	BBB+/Negative/—	5
Dayton Power & Light Co.	BBB+/Negative/A-2	4
DPL Inc.	BBB+/Negative/A-2	6
Portland General Electric Co.	BBB+/CW-Neg/A-2	4
TEPPCO Partners L.P.	BBB/Stable/—	4
TE Products Pipeline Co. L.P.	BBB/Stable/—	4
Florida Gas Transmission Co.	BBB/Stable/—	2
NUI Corp.	BBB/Stable/—	3
Kinder Morgan Inc.	BBB/Stable/A-2	5
PPL Energy Supply LLC	BBB/Stable/—	7
PPL Corp.	BBB/Stable/A-2	7
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
PSEG Power LLC	BBB/Stable/—	7

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Exhibit No.___ (KON-1)
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U.S. Electric/Gas/Water Companies continued

Company	Corporate Credit Rating	Bus. Prof.
Public Service Enterprise Group Inc.	BBB/Stable/A-2	6
PSEG Energy Holdings, Inc.	BBB/Stable	8
Bangor Hydro-Electric Co.	BBB/Stable/—	5
Entergy Arkansas Inc.	BBB/Stable/—	6
Entergy Louisiana Inc.	BBB/Stable/—	6
Entergy Mississippi Inc.	BBB/Stable/—	7
Entergy New Orleans Inc.	BBB/Stable/—	7
Entergy Corp.	BBB/Stable/—	6
Pinnacle West Capital Corp.	BBB/Stable/—	5
Pinnacle West Energy Corp.	BBB/Stable/—	7
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Great Plains Energy Inc.	BBB/Stable/—	6
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Black Hills Power Inc.	BBB/Stable/—	5
Black Hills Corp.	BBB/Stable/A-2	7
Potomac Capital Investment Corp.	BBB/Stable/A-2	7
Empire District Electric Co.	BBB/Stable/A-2	5
Xcel Energy Inc.	BBB/Negative/A-3	6
Northern States Power Co.	BBB/Negative/A-3	4
Southwestern Public Service Co.	BBB/Negative/A-3	4
Public Service Co. of Colorado	BBB/Negative/A-3	4
NRG Energy Inc.	BBB/Negative/	9
PacifiCorp Group Holdings Co.	BBB/Negative/A-2	4
Jersey Central Power & Light Co.	BBB/Negative/A-2	4
Pennsylvania Electric Co.	BBB/Negative/A-2	5
Metropolitan Edison Co.	BBB/Negative/A-2	5
Ohio Edison Co.	BBB/Negative/—	6
Cleveland Electric Illuminating Co.	BBB/Negative/—	6
Toledo Edison Co.	BBB/Negative/—	6
FirstEnergy Corp.	BBB/Negative/—	6
GPU Inc.	BBB/Negative/A-2	5
Southwestern Energy Co.	BBB/Negative/—	8
Duquesne Light Co.	BBB/Negative/A-2	4
DQE Inc.	BBB/Negative/A-2	5
Williams Gas Pipe Line Central	BBB/Negative/A-2	3
Transcontinental Gas Pipe Line Corp.	BBB/Negative/A-2	3
Texas Gas Transmission Corp.	BBB/Negative/A-2	4
The Williams Cos. Inc.	BBB/Negative/A-2	3
NiSource Inc.	BBB/Negative/A-2	4
Columbia Energy Group	BBB/Negative/—	4
Bay State Gas Co.	BBB/Negative/—	3
Northern Indiana Public Service Co.	BBB/Negative/—	5
SEMCO Energy Inc.	BBB/Negative/—	3
Reliant Resources Inc.	BBB/CW-Neg/A-2	7
Reliant Mid-Atlantic Holding LLC	BBB/CW-Neg/—	7
Orion Power Holdings Inc.	BBB/CW-Neg/—	7
Aquila Inc.	BBB/CW-Neg/A-2	6
Aquila Merchant Services Inc.	BBB/CW-Neg/—	9
Central Illinois Light Co.	BBB-/CW-Pos/—	4
CILCORP	BBB-/CW-Pos/—	4

Company	Corporate Credit Rating	Bus. Prof.
Green Mountain Power Corp.	BBB-/Positive/—	7
El Paso Electric Co.	BBB-/Stable/—	6
Mirant Americas Generating Inc.	BBB-/Stable/—	7
Mirant Corp.	BBB-/Stable/A-3	7
Mirant Americas Energy Marketing	BBB-/Stable/—	8
Entergy Gulf States Inc.	BBB-/Stable/—	6
System Energy Resources Inc.	BBB-/Stable/—	7
Central Vermont Public Service Corp.	BBB-/Stable/—	6
Texas-New Mexico Power Co.	BBB-/Stable/—	5
Public Service Co. of New Mexico	BBB-/Stable/—	6
Puget Sound Energy Inc.	BBB-/CW-Dev/A-3	5
Washington Natural Gas Co.	BBB-/CW-Dev/A-3	5
Puget Sound Power & Light Co.	BBB-/CW-Dev/A-3	5
Puget Energy Inc.	BBB-/CW-Dev/A-3	5
Northern Natural Gas Co.	BBB-/CW-Dev/—	3
Southwest Gas Corp.	BBB-/Negative/—	4
Indianapolis Power & Light Co.	BBB-/Negative/—	4
IPALCO Enterprises Inc.	BBB-/Negative/—	4
Illinois Power Co.	BBB-/CW-Neg/A-2	6
Dynegy Holdings Inc.	BBB-/CW-Neg/A-3	6
Illinova Corp.	BBB-/CW-Neg/—	7
Dynegy Inc.	BBB-/CW-Neg/A-3	7
El Paso Energy Partners L.P.	BB+/Positive/—	6
Market Hub Partners Storage L.P.	BB+/Stable/—	7
Sonat Energy Services Co.	BB+/Stable/—	9
Western Gas Resources Inc.	BB+/Stable/—	7
Westar Energy Inc.	BB+/Negative/—	6
Avista Corp.	BB+/Negative/—	5
AmeriGas Partners L.P.	BB+/Negative/—	5
Tucson Electric Power Co.	BB/Stable/—	6
Southern California Edison Co.	BB/CW-Dev/—	8
*Consumers Energy Co.	BB/Negative/—	6
*CMS Panhandle Pipeline Cos.	BB/Negative/—	4
*CMS Energy Corp.	BB/Negative/—	6
Heating Oil Partners L.P.	B+/Stable/—	3
Sierra Pacific Power Co.	B+/CW-Neg/B	5
Nevada Power Co.	B+/CW-Neg/B	6
Sierra Pacific Resources	B+/CW-Neg/—	5
EOTT Energy Partners L.P.	B+/CW-Neg/—	8
Edison International	B-/Developing/—	8
Transwestern Pipeline Co.	CC/CW-Dev/—	5
Pacific Gas & Electric Co.	D/—/D	9
Enron Corp.	D/—/—	6
Azurix Corp.	D/—/—	4

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Case No. AVU-E-____
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (KON-2) OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

Exhibit KON-2
Idaho PCA
Summary of Idaho Power Cost Deferrals

Line No.			Total Jul-01 - Jun 02	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
	Actual Less Authorized - System														
1	555 Purchased Power		$130,717,023	$68,330,911	$35,522,614	$36,800,565	$6,881,217	$7,385,938	$10,002,294	-$4,484,142	-$5,604,393	-$5,080,931	-$7,399,411	-$6,594,811	-$5,042,828
2	501 Thermal Fuel		-19,794,594	-1,120,183	-1,938,624	-1,973,689	-2,120,772	-2,680,577	-1,999,019	-714,947	-1,016,917	-1,651,497	-1,234,444	-1,661,377	-1,682,548
3	547 CT Fuel		17,604,786	5,885,890	4,322,740	3,066,979	3,187,691	-583,123	132,802	-603,055	47,927	1,630,853	45,152	118,413	352,517
4	447 Sale for Resale		-12,341,597	-11,897,363	-3,986,853	-12,142,500	-7,776,677	-5,686,606	-6,393,361	6,156,674	6,090,362	5,174,150	6,255,212	7,423,527	4,441,838
5	PGE Capacity Revenue True-up		-15,766,350	-1,145,450	-1,145,450	-1,145,450	-1,386,000	-1,386,000	-1,386,000	-1,362,000	-1,362,000	-1,362,000	-1,362,000	-1,362,000	-1,362,000
6	Potlatch Direct Assignment Credit to ID		-3,257,250							-558,000	-504,000	-558,000	-539,250	-558,000	-540,000
7	Subtotal		97,162,018	60,053,805	32,774,427	24,605,905	-1,214,541	-2,950,368	356,716	-1,565,470	-2,349,021	-1,847,425	-4,234,741	-2,634,248	-3,833,021
8	Northeast CT Emissions/Lease Expense		121,628	81,695	35,968	4,239	3,776	0	0	-4,050	0	0	0	0	0
9	Devil's Gap		8,736,214			1,555,052	7,181,162	0	0	0	0	0	0	0	0
10	Kettle Falls Bi-Fuel		1,110,021			164,968	36,469	110,036	117,757	116,456	95,035	115,432	118,725	119,300	115,843
	Actual Less Authorized - ID Allocation	33.18%													
11	555 Purchased Power		43,371,909	22,672,197	11,786,403	12,210,427	2,283,187	2,450,654	3,318,761	-1,487,838	-1,859,538	-1,685,852	-2,455,123	-2,188,158	-1,673,211
12	501 Thermal Fuel		-6,567,846	-371,677	-643,235	-654,870	-703,672	-889,415	-663,275	-237,219	-337,413	-547,967	-409,589	-551,245	-558,269
13	547 CT Fuel		5,841,267	1,952,938	1,434,285	1,017,624	1,057,676	-193,480	44,064	-200,094	15,902	541,117	14,981	39,289	116,965
14	447 Sale for Resale		-4,094,943	-3,947,545	-1,322,838	-4,028,882	-2,580,301	-1,886,816	-2,121,317	2,042,784	2,020,782	1,716,783	2,075,479	2,463,126	1,473,802
15	PGE Capacity Revenue True-up		-5,231,277	-380,060	-380,060	-380,060	-459,875	-459,875	-459,875	-451,912	-451,912	-451,912	-451,912	-451,912	-451,912
16	Potlatch Direct Assignment Credit to ID		-1,080,754	0	0	0	0	0	0	-185,144	-167,227	-185,144	-178,923	-185,144	-179,172
17	Potlatch Direct Assignment to ID		3,257,250							558,000	504,000	558,000	539,250	558,000	540,000
18	Northeast CT Emissions/Lease Expense		40,356	27,106	11,934	1,407	1,253	0	0	-1,344	0	0	0	0	0
19	Devil's Gap		2,898,676	0	0	515,966	2,382,710	0	0	0	0	0	0	0	0
20	Kettle Falls Bi-Fuel		368,305	0	0	54,736	12,100	36,510	39,072	38,640	31,533	38,300	39,393	39,584	38,437
21	Subtotal		38,802,943	19,952,959	10,886,489	8,736,348	1,993,078	-942,422	157,430	75,873	-243,873	-16,675	-826,444	-276,460	-693,360
22	Idaho Retail Revenue Adjustment		1,523,271	524,337	32,534	-395,827	-114,402	487,398	384,792	827,509	19,681	91,718	-67,814	29,196	-295,851
23	Wood Power Inc. Amortized Expense		457,925								327,261	32,666	32,666	32,666	32,666
24	Net Fuel Expense not incl in Acct 547		13,060,877	236,579	877,974	1,096,573	861,814	2,810,446	2,298,762	33,012	910,887	668,612	842,089	891,798	1,532,331
25	Subtotal		53,845,016	20,713,875	11,796,997	9,437,094	2,740,490	2,355,422	2,840,984	936,394	1,013,956	776,321	-19,503	677,200	575,786
	Customer Share	90%													
26	555 Purchased Power		39,034,724	20,404,978	10,607,762	10,989,385	2,054,868	2,205,589	2,986,885	-1,339,053	-1,673,584	-1,517,266	-2,209,610	-1,969,340	-1,505,890
27	501 Thermal Fuel		-5,911,063	-334,509	-578,912	-589,383	-633,305	-800,474	-596,948	-213,497	-303,672	-493,170	-368,630	-496,121	-502,442
28	547 CT Fuel		5,257,141	1,757,644	1,290,857	915,862	951,908	-174,132	39,658	-180,085	14,312	487,005	13,483	35,360	105,269
29	447 Sale for Resale		-3,685,448	-3,552,791	-1,190,554	-3,625,994	-2,322,271	-1,698,134	-1,909,185	1,838,506	1,818,704	1,545,105	1,867,931	2,216,813	1,326,422
30	PGE Capacity Revenue True-up		-4,708,152	-342,054	-342,054	-342,054	-413,888	-413,888	-413,888	-406,721	-406,721	-406,721	-406,721	-406,721	-406,721
31	Potlatch Direct Assignment Credit to ID		-972,680							-166,630	-150,504	-166,630	-161,031	-166,630	-161,255
32	Potlatch Direct Assignment to ID		2,931,525							502,200	453,600	502,200	485,325	502,200	486,000
33	Northeast CT Emissions/Lease Expense		36,320	24,395	10,741	1,266	1,128	0	0	-1,210	0	0	0	0	0
34	Devil's Gap		2,608,808	0	0	464,369	2,144,439	0	0	0	0	0	0	0	0
35	Kettle Falls Bi-Fuel		331,475	0	0	49,262	10,890	32,859	35,165	34,776	28,380	34,470	35,454	35,626	34,593
36	Idaho Retail Revenue Adjustment		1,370,943	471,903	29,281	-356,244	-102,962	438,658	346,313	744,758	17,713	82,546	-61,033	26,276	-266,266
37	Wood Power Inc. Amortized Expense		412,131								294,535	29,399	29,399	29,399	29,399
38	Net Fuel Expense not incl in Acct 547		11,754,790	212,921	790,177	986,916	775,633	2,529,401	2,068,886	29,711	819,798	601,751	757,880	802,618	1,379,098
39	Subtotal		48,460,514	18,642,487	10,617,298	8,493,385	2,466,440	2,119,879	2,556,886	842,755	912,561	698,689	-17,553	609,480	518,207
40	Centralia Capital & O&M Credit		-2,817,996	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833	-234,833
41	Subtotal		45,642,518	18,407,654	10,382,465	8,258,552	2,231,607	1,885,046	2,322,053	607,922	677,728	463,856	-252,386	374,647	283,374
42	Adjustments		-256,013	-256,013											
43	Buyback costs		2,169,263	537,282	702,595	477,301	-9,897	464,187	-2,205						
44	Kettle Falls Bi-Fuel		53,381			17,061	1,548	32,893	49		5,047				-3,217
45	Monroe Street - Cost for No Aesthetic Spill		4,666									4,666			
46	Reverse Boulder Park Test Power Cost		-8,423											-8,423	
47	Revaluation of Othello CT		836,979				420,118	119,981	312,032					-15,152	
48	**Total Power Cost Deferrals**		48,442,371	18,688,923	11,085,060	8,752,914	2,643,376	2,502,107	2,631,929	607,922	682,775	468,522	-252,386	351,072	280,157
49	Transfer of under-(rebate)/surcharge		292,996	-49,073						342,069					
50	PGE Monetization Accelerated Amortization		-20,783,521				-2,309,281	-2,309,280	-2,309,280	-2,309,280	-2,309,280	-2,309,280	-2,309,280	-2,309,280	-2,309,280
51	Gas Swaps, FAS133		0						4,077,276	-4,077,276					
52	Interest		2,764,590	182,219	278,893	322,848	172,181	341,628	336,799	330,319	99,153	196,252	182,603	167,244	154,451
53	Net Entries to Deferral Account		30,716,436	18,822,069	11,363,953	9,075,762	506,276	534,455	4,736,724	-5,106,246	-1,527,352	-1,644,506	-2,379,063	-1,790,964	-1,874,672
54	Deferral Balance Beginning of Month			30,007,057	48,829,126	60,193,079	69,268,841	69,775,117	70,309,572	75,046,296	69,940,050	68,412,698	66,768,192	64,389,129	62,598,165
55	Deferral Balance End of Month			$48,829,126	$60,193,079	$69,268,841	$69,775,117	$70,309,572	$75,046,296	$69,940,050	$68,412,698	$66,768,192	$64,389,129	$62,598,165	$60,723,493

Exhibit No.___ (KON-2)
Case No. AVU-E-____
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (KON-3) OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

FT
FINANCIAL TIMES
Energy

Megawatt Daily's

MarketReport

Monday, December 11, 2000

Indexes and Transaction Record for 12/11/00

Explanations

Index — Volume-weighted average of all trades reported.
Absolute Low — Lowest trade reported.
Absolute High — Highest trade reported.
Trading Volume Reported — Volume of trades per hour for each of 16 peak hours. This figure is a total of all trading volume reported to MWD for each delivery site; because every effort is made to capture both sides of every deal reported, MWD recognizes that this figure includes duplicate volumes, and the figure should be used as a trend indicator not necessarily as an indicator for transmitted volumes.
Total Peak Volume — Volume for all peak hours, found by multiplying the trading volume by 16.
Number of Trades — This figure is calculated by dividing the trading volume reported by 50 MW/h for all Central and East listings; numbers of trades for delivery points in the West are calculated by dividing by 25 MW/h.

Methodology

The prices displayed in the table to the right are for power, in $/MWh, traded at the delivery points and regions listed. Peak hours are 0600-2200 hrs.; PJM and New York peak hours are 0700-2300. Off-peak hours generally start at 2200 hrs. on the date before the delivery date and end at 0600 on the delivery date. Not included are 24-hour deals categorized in some NERC regions as off-peak hours over Saturdays and Sundays. Transactions at the hubs listed in the separate table at the top of this page are financially firm. Deals at other locations may be unit-firm or system-contingent, and may include capacity reservation charges. Transactional data is gathered from utilities, marketers, co-ops, brokers, municipals and government power agencies. Deals done in the West are excluded if done after 1015 hrs. PT; deals done in the East and Central areas are excluded if done after 1100 hrs. CT. The middle column is the volume-weighted average of all deals reported and should be used for indexing purposes. The common range represents pricing for most of the trading volume; the absolute range represents lowest and highest prices reported. Copyright 2000 by Financial Times Energy.

Trades for Standard 16-Hour Daily Products; *all prices and volumes in $/MWh*

Delivery Point	Weighted Average Index	Absolute Low	Absolute High	Trading Volume Reported	All Peak Hours Volume	Number of Trades Reported
West						
COB	$3,000.00	$3,000.00	$3,000.00	25	400	1
Four C	—	—	—	0	0	0
Mead, Nev.	—	—	—	0	0	0
Mid-Columbia	$4,175.00	$3,000.00	$5,000.00	100	1,600	4
NP15	—	—	—	0	0	0
Palo Verde	$395.00	$360.00	$425.00	75	1,200	3
SP15	$350.00	$350.00	$350.00	25	400	1
Central						
ERCOT-B	$65.59	$60.00	$75.00	850	13,600	17
Ameren	—	—	—	0	0	0
Com Ed, into	$44.39	$40.00	$52.00	900	14,400	18
MAIN North	$63.33	$58.00	$120.00	300	4,800	6
MAIN South	—	—	—	0	0	0
MAPP North	$60.94	$50.00	$75.00	160	2,560	3
MAPP South	—	—	—	0	0	0
Entergy, into	$67.40	$50.00	$76.00	2,000	32,000	40
SPP	$65.90	$58.00	$75.00	500	8,000	10
East						
Cinergy	$48.47	$44.00	$53.00	6,550	104,800	131
North ECAR	$51.52	$45.00	$55.00	1,405	22,480	28
PJM-West	$49.01	$46.00	$54.00	2,800	44,800	56
Nepool	$74.00	$72.00	$80.00	500	8,000	10
NY Zone G	$67.50	$67.50	$67.50	200	3,200	4
NY Zone A	$57.85	$57.00	$59.00	600	9,600	12
NY Zone J	$81.00	$81.00	$81.00	50	800	1
VaCar	$46.00	$46.00	$46.00	150	2,400	3
Southern	$45.00	$45.00	$45.00	50	800	1
TVA, into	$43.92	$43.00	$47.00	1,200	19,200	24
Fla.-Ga.	$42.50	$40.00	$45.00	100	1,600	2
Fla. in-state	—	—	—	0	0	0

Trades for Standard Forward Products *(all prices in $/MWh)*

Delivery Point	Next Week 12/18 to 12/22		Balance of Month 12/12 to 12/31		Prompt Month 01/01				
	Low	High	Low	High	Low	High	Index	All pk. hrs. vol.	No. of Trades
West									
COB	—	—	—	—	—	—	—	0	0
Mid-Columbia	—	—	—	2,000.00	575.00	800.00	675.00	1,200	3
NP15	—	—	—	—	—	320.00	320.00	400	1
Palo Verde	—	—	—	—	250.00	375.00	300.00	1,200	3
SP15	—	—	—	—	—	—	—	0	0
Central									
Com Ed, into	—	75.00	—	68.00	—	—	—	0	0
Entergy, into	—	—	—	—	—	—	—	0	0
East									
Cinergy, into	72.00	85.00	—	70.00	—	—	—	0	0
PJM-West	—	—	—	61.00	—	—	—	0	0
NEPOOL	82.00	90.00	82.00	85.00	—	—	—	0	0
NY Zone G	—	—	—	—	—	—	—	0	0
NY Zone A	60.00	60.50	—	—	—	—	—	0	0
NY Zone J	—	—	—	—	—	—	—	0	0
TVA, into	—	66.00	—	—	—	—	—	0	0

Ranges and Indexes of Trades for Standard Off-Peak Products

Delivery Date: 12/11/00

	Wtd. Av. Index	Absolute Low	Absolute High	Trading Vol. Reported
West				
COB	—	—	—	0
Four C	$275.00	$275.00	$275.00	25
Mead, Nev.	—	—	—	0
Mid-C	$2,016.67	$1,550.00	$2,500.00	75
NP15	—	—	—	0
Palo Verde	$275.00	$275.00	$275.00	25
SP15	—	—	—	0
Central				
ERCOT-B	—	—	—	0
Ameren	—	—	—	0
Com Ed, into	$19.00	$19.00	$19.00	300
MAIN North	—	—	—	0
MAIN South	—	—	—	0
MAPP North	$21.00	$21.00	$21.00	125
MAPP South	$20.00	$20.00	$20.00	100
Entergy, into	—	—	—	0
SPP	$17.04	$13.00	$23.50	260
East				
Cinergy	—	—	—	0
North ECAR	$19.50	$19.00	$19.55	1,157
PJM-West	—	—	—	0
Nepool	—	—	—	0
NY Zone G	—	—	—	0
NY Zone A	—	—	—	0
NY Zone J	—	—	—	0
VaCar	—	—	—	0
Southern	—	—	—	0
TVA, into	—	—	—	0
Fla.-Ga.	$25.00	$25.00	$25.00	50
Fla. in-state	—	—	—	0

MGE, Alliant propose plant for university

A proposal between Madison Gas & Electric (MGE), Alliant Energy, the University of Wisconsin-Madison and Wisconsin's Department of Administration may result in a $170 million, 90-to 100-MW, natural gas-fired power plant on school ground that could solve a long-term energy crunch facing both the university and the city, the parties said last week.

If the plant gets all approvals necessary, the two utilities will jointly plan and oversee construction of the facility, which is anticipated to start in summer 2002. Plant operation is expected to begin in late 2003 or spring 2004.

Once construction is complete, MGE would own the facility with a third-party investor but would retain full operational control. Alliant will act as project manager. Although not a specified owner, Alliant will be paid for its services, company representative Chris Schoenherr said.

The proposed site at the university has the necessary infrastructure in place to support the facility, including electric transmission lines, a power substation and natural gas lines. MCM

Dailies scream to $5,000 at Mid-C, $3,000 at COB

Western Markets

The relentless upswing in next-day prices prevailed, with dailies trading to $5,000 at Mid-Columbia and $3,000 at COB.

"This is history," one source said. "Someone who buys power at that price [$5,000] is walking wounded. Actually, they're not even walking."

Overall, next-day volume was sparse. Deals arranged for today's delivery traded up to $425 at Palo Verde and near $350 at SP15.

In the bilateral market, off-peak for today traded near $275 at Palo Verde and at Four Corners.

The extreme pressure on prices carried over into the term markets, where balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day.

Crippled by idled power plants and tight energy imports, the state's power grid strained to meet the load going into the weekend. The danger of blackouts, caused by cold weather and an unprecedented drop in the energy supply, was expected to grow severely today, as an Arctic front blows down the West Coast from Canada.

Going into the weekend, California Power Exchange prices for Saturday peak were $251.23, with off-peak $256.79 and the 24-hour weighted average at $252.79. A day earlier, prices were fractions of a cent above $250.

The Bonneville Power Administration had no surplus power to sell at least through Saturday.

Friday began with a Stage 2 declaration by the California Independent System Operator — the fifth such declaration in as many days and the ninth in three weeks.

Also firming up power prices was the cost of natural gas, which reached as high as $63 at COB/Malin, Ore., $61 at the Pacific Gas & Electric Citygate and $55 at the Southern California Border.

At Palo Verde, January ranged $250-$375 and near $320 at NP15.

Second-quarter 2001 traded as high as $215 at Mid-C and in a tight range to $190 at Palo Verde.

Third-quarter 2001 sold at or above $290 at Palo Verde. KW/NM

Transmission problems force Entergy to mid $70s

Central Markets

Entergy dailies opened at $50, about $23 lower than the previous day's trades. However, they soon regained ground, passing the high from the day before.

By the end of the day deals were done at $76, a net gain of $1. Traders were not certain what was driving prices up, but suspected transmission constraints.

In MAIN, ComEd dailies fell even further, about $16 to the low $50s. Off-peak sold near $19.

Weekend trades moved in the low $30s and off-peak sold in the low $20s.

After undergoing a hot shutdown last week, ComEd's 828-MW nuke unit, Quad Cities 1, began powering back up after repairs.

Northern MAIN dailies moved around the low $60s. However, the same unfortunate player who all last week caught the high deals paid around $120 for a much-needed package. Weekend peak sold in the upper $20s.

Ameren reported weekend off-peak deals near $20.

Light weekend demand helped push northern MAPP dailies down about $20, to $75.

Central Generation Outage Report for December 11

Information from the Nuclear Regulatory Commission is sometimes outdated, and not all utilities respond to requests for verification of unit status. Copyright 2000 by FT Energy

Unit Name, Operator	MW	NERC Region	Unit Status	Scheduled restart or outage date
LaSalle 2 ComEd	828	MAIN	Nuclear; operating at 100% following Oct. 6 refueling outage	Full power Dec. 8
Quad Cities 1 ComEd	828	MAIN	Nuclear; operating at 1% after hot shutdown Dec. 6	Start up on Dec. 7

FT
FINANCIAL TIMES Energy

. nursday, May 31, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Massey calls for inquiry into market power methodology

FERC Commissioner William Massey, dissenting from two orders yesterday, strongly called for the commission to give up its current method of market power analysis.

"Our current standard is just plain outdated, inadequate and unreliable," Massey said.

Massey has previously attacked the "hub-and-spoke" method of market power analysis, which presumes market power if any single market participant holds a 20% market share.

In April, Pacific Gas & Electric and Southern California Edison made a similar argument in asking FERC to deny renewal of market-based rate authority to Williams Energy Marketing and Trading *(MWD 4/4)*. The two utilities argued that while Williams controls less than 20% of the generation resources in the state, it is still able to exercise market power. To renew its market-based rate authority, Williams should perform an analysis of market power using other means, the utilities said.

Massey said the events of the California wholesale power market — where no single generator or power seller holds close to 20% market share — during the past year indicate that market power can be exercised by any player holding a much smaller piece. The "20-percent share threshold is too simplistic," he said.

In one decision issued yesterday in draft form, the commission granted market-based rate authority to Sierra Southwest Cooperative

(Continued on page 8)

INSIDE THE MARKET REPORT

Key Hub Trades for Standard 16-Hour Daily Products

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page X.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	180.20	125
Mid-Columbia	176.67	1,425
⁻alo Verde	175.64	1,375
ʔCOT-B	35.12	1,500
ᴗom Ed	16.57	350
Entergy	27.24	5,150
Cinergy	17.22	9,620
PJM	24.25	5,600
TVA	17.74	1,450

Bush, Davis agree to disagree on price caps

President Bush and California Gov. Gray Davis have a "fundamental disagreement over whether or not California is entitled to price relief," Davis said after the two met privately in Los Angeles on Tuesday to discuss the state's energy crisis.

Despite intensified arguments that continuing high wholesale power prices will hurt California and the larger U.S. economy, Davis was unable to persuade Bush to support temporary price controls in the state.

Bush again declined Davis' requests for caps on power prices. But California is legally "entitled" to price caps, Davis argued during a press briefing following his meeting with Bush.

"The president did not create this problem," Davis said of the power crisis. "Like me, he inherited a mess." Davis has lately stuck to his message that California is doing all it can to bring new power plants online and to reduce consumption.

The governor, who acknowledged the president's efforts in other areas to help California, said he and Bush have a "fundamental disagreement" over the issue of price caps. Davis said caps are necessary for California, which is short generation and could pay $50 billion to $70 billion this year for its

(Continued on page 7)

State regulators add views to Bush energy plan

Utility regulators from 13 states this week issued a set of national electricity policy recommendations directed at both state and federal lawmakers and officials.

"We feel timing is critical," Montana Public Service Commissioner Bob Anderson, leader of the effort, said. "President Bush issued his energy policy recommendations recently, and we commend him for it. Our recommendations will complement his and enrich the policy debate."

The report identifies seven principal policy areas. "These comprehensive policies present a balance between supply and demand, while recognizing the important role of energy efficiency, as well as environmental and consumer protection," Anderson said.

Policy-makers should improve existing generation technologies to increase efficiency and minimize environmental impact, the report says. Policies also should promote fuel diversity including "green" power sources.

To ensure reliability, transmission and distribution, companies should provide "adequate and efficient generation," the report says. Delivery companies also should provide a certain minimum level of reliability to all customers "as a part of basic electric service."

Because 95% of customer outages re-

(Continued on page 2)

Davis ready to take his case to court ... *(from page 1)*

wer purchases. Davis told Bush he would "pursue every recourse available" to "ensure that markets are functional and rates are just and reasonable."

Davis also said he hoped Bush would communicate to the two new FERC members "that California is entitled to price relief."

So far, federal regulators have taken steps to ensure a competitive power market in the long term, but they have refused to implement short-term caps.

In a meeting that Davis described as "cordial," the governor said he informed the president that he would do all he could to fight for Californians against high power prices charged by generators that Davis accuses of market manipulation.

Davis indicated that action would include lodging a lawsuit against the regulators at FERC. The agency's legal mandate is to ensure that power prices are "just and reasonable," and FERC ruled in a December order that the market was not competitive.

In that order and in subsequent actions, FERC implemented a series of measures aimed ironing out faults in California's market .ucture and at limiting wholesale prices during power emergencies.

Davis and other state officials claim those actions have failed to limit price spikes and will not help the state avoid blackouts and high costs for power this summer. Three state agencies and the state Assembly have filed petitions within the last few days requesting a rehearing of the agency's latest order on price mitigation measures during power emergencies.

Speaking after his meeting with Bush, Davis indicated those filings are the first step in a legal process that could result in lawsuits against FERC. The state must first exhaust all legal and procedural remedies with FERC before turning to the courts, he said.

A lawsuit filed last week in federal court by senior Democrats in the state Senate and Assembly was dismissed Tuesday because those legislators had not first gone through all appeals channels directly available with FERC, Davis said. A three-judge panel at the Ninth Circuit Court of appeals dismissed the .tion, saying only that the "petitioners have not demonstrated that this case warrants the intervention of this court."

FERC Chairman Curt Hebert seemed unfazed at the prospect of Davis' threatened legal action.

"I think the Ninth Circuit made it clear, FERC is doing our job appropriately," Hebert said at yesterday's commission meeting.

In addition to legal remedies to force federal regulators to act, Davis also pointed to Senate Democrats, who will take control of that body early next month, as potential partners who could help California by approving price cap legislation. California's Democratic senators, Dianne Feinstein and Barbara Boxer, have both introduced bills that would impose price caps in Western markets.

"I'm looking forward to working with the newly constituted United States Senate to make sure that the problems of California and the West ... get a full airing," Davis said.

Davis attempted to sway Bush in favor of price caps by arguing that a crisis-damaged California economy will hurt the nation and that the federal government is required by law to ensure reasonable rates.

But Bush, who has been steadfastly against price caps, explained his opposition to the caps in a speech at the World Affairs Council in Los Angeles. He also noted that the Clinton administration did not call for the imposition of price caps.

"We will not take any action that makes California's problems worse, and that's why I oppose price caps," Bush said. "Price caps do nothing to reduce demand, and they do nothing to increase supply. This is not only my administration's position, this was the position of the prior administration."

The president said his administration would help California by expanding the state's main north-south transmission line, Path 15; requiring federal facilities in the state to reduce demand 10%; and providing additional funding to low-income consumers to help offset rising electricity and gas prices.

The president also told Davis that he would dispatch newly installed FERC Commissioner Pat Wood, the former head of the Public Utility Commission of Texas, to California to investigate why natural gas prices are higher in the state than in other parts of the country.

Davis called Bush's offer "good news" and said the president agreed with him that it "made little sense for California to receive Texas natural gas at roughly $15 per British thermal unit, when New York is receiving the same gas at roughly $5.95 per British thermal unit."

The president wants Wood "to see if there is market manipulation" in the California natural gas market and "to review the wisdom of the Federal Energy Regulatory Commission's decision two years ago," when, Davis said, FERC suspended a tariff that controlled the transportation prices of natural gas when it flows from Texas to other parts of the country. MS/ADP

Energy economists to testify on market manipulation

California legislators will hear testimony later today from two prominent energy economists on allegations that power generators have colluded to drive up prices in the state's wholesale power markets.

Severin Borenstein and Alfred Kahn are scheduled to testify before the state Senate's Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. Kahn may address issues of physical withholding of power supplies by generators, while Borenstein would likely brief senators on economic models exhibiting generators' ability to exercise market power to raise prices, a representative of committee Chairman Joseph Dunn indicated.

The select committee has taken testimony in three earlier hearings from state energy officials on plant outages and their effect on prices. Within the next several weeks, the committee also plans to hear from generators, according to the representative.

The "big five" out-of-state generators — Duke, Dynegy, Reliant, Williams/AES and Mirant — will be invited to give their side of the story, as will energy marketer Enron, he said. Those companies have been repeatedly accused by state officials of gouging consumers and engaging in illegal activity.

Borenstein, Kahn and eight other economists last week co-signed a letter to President Bush arguing for the imposition of short-term price caps on wholesale markets. The economists asserted that the failure of deregulation in California could harm the development of competitive electricity markets across the nation. ADP

FT
FINANCIAL TIMES
Energy

Thursday, June 14, 2001

MegawattDaily

From the publisher of Gas Daily® and Coal Outlook

Calif. inks deal with QFs, will release details on long-term contracts

California officials have reached agreements with two groups of small generators that will return the full amount of power contracted by those facilities back to the market, adding between 100 MW and 300 MW of additional power to the state's grid this summer, Gov. Gray Davis said yesterday.

Contracts signed with two groups of qualifying facilities establish new prices for the power they will supply to the second largest investor-owned utility in the state, Southern California Edison, Davis said.

The deals also provide for marginal payment of back debts owed by the utility to the generators, provided the individual facilities produce additional energy at their facilities.

But the effective date of the agreed-to prices is linked to approval by the state Legislature of an agreement between SoCalEd's parent company and the state. The memorandum of understanding between Davis and Edison International would pave the way for the state's purchase of the utility's power lines.

Negotiations between the state and the QFs have resulted in bringing 95% of the power produced by those generators back onto the market, Davis said. Numerous QFs had been withholding their output from the market in protest over nonpayment of past bills by California's largest utilities.

The output of QFs serves up to one-third of California's total

(Continued on page 8)

INSIDE THE MARKET REPORT

Key Hub Trades for Standard 16-Hour Daily Products 06/14/01

Weighted average index prices (in $/MWh) and volumes are shown for selected major hubs. More detailed price information is available on page 3.

Delivery Point	Weighted Average Index	Trading Volume Reported
COB	57.33	75
Mid-Columbia	56.20	2,100
Palo Verde	62.59	2,025
ERCOT-B	41.17	1,950
ComEd	49.10	2,050
Entergy	51.98	5,900
Cinergy	53.44	11,000
PJM	55.26	8,750
TVA	52.28	2,000

Cheney, Hebert hold firm on energy policy

Vice President Dick Cheney and FERC Chairman Curt Hebert both pledged yesterday to stay the course when it comes to energy policy. But while both men faced a friendly audience at the Energy Efficiency Forum yesterday at the National Press Club in Washington, their remarks seemed aimed more at winning over a skeptical audience in California.

Cheney and Hebert emphasized the importance of market remedies — and reaffirmed their opposition to price controls. Hebert, for one, was adamant that recent FERC measures would suffice to create a better-functioning market out West.

"California does not mean an end to competition," he said.

Cheney repeated the main selling points of the administration's recently introduced national energy policy. And while he warned of the possible economic impact of the current supply situation, the vice president said that the nation's energy problems could be fixed with a dose of "resolve, ingenuity and clarity of purpose."

The remedies that Cheney listed include the construction of a new gas pipeline that would run from Alaska's North Slope, a proposal that Cheney called "relatively non-

(Continued on page 7)

FERC clears National Grid purchase of NiMo

With a specific provision on accounting procedures, FERC yesterday approved New York-based Niagara Mohawk Holdings' proposed acquisition by National Grid USA, the U.S. branch of the British transmission utility.

National Grid USA, which operates two transmission and distribution utilities in New England, offered to buy NiMo last September in a $3 billion cash and stock transaction that includes assumption of $5.9 billion in NiMo debt *(MWD 9/6/00)*. NiMo serves 1.5 million electricity and 540,000 natural gas customers in upstate New York.

The combined company, which would be a new holding company registered in the United Kingdom under the name National Grid Group (the same name as the existing overall company), would serve 3.3 million electricity customers in the United States, placing it among the top 10 in terms of customers served.

NiMo will continue as the local utility and will remain under the regulations of New York state.

Both companies have sold substantially all of their generation assets — NiMo's major remaining asset, its interests in the Nine Mile Point nuclear plants, has been committed to Constellation Energy Group — so FERC found no competitive market issues there.

(Continued on page 2)

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (KON-4) OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

AVISTA Corporation

Energy Resources

Kettle Fall – "Bi-Fuel" (Nat. Gas/Oil) Generation
April 7, 2001

Situation
Although the company has worked hard to balance the utility's load and resource positions, there are conditions that require additional short-term supplies of power. It is prudent for us to protect ourselves from short-term deficiencies, variability in available power from hydro projects, variability in loads and generation unit outage risk given the high prices and volatility evident in the competitive electric power market. Building additional generation suitable for economic short-term supply is one such way to obtain that protection.

Kettle Falls "Bi-Fuel" Generation
We have received a proposal for 10.8 megawatts of generation that would be located at the Kettle Falls Generating Station. The generation package consists of "bi-fuel" (simultaneous natural gas and oil operation) reciprocating engine generators. This bi-fuel generation is particularly suited to the Kettle Falls location. Natural gas may not be available during all time periods on the Kettle Falls gas lateral. This type of reciprocating generation unit will shift from 80%/20% gas/oil operation to 100% oil operation under conditions when gas is not available. 100% oil operation could occur up to 4 months per year. This is the scenario used in our economic analysis.

These are new units that are assembled in Canada. The project consists of six 1.8MW units. Half of the units could be delivered as early as mid-April with the other half in mid-May. Units are in weatherproof enclosures and would have additional sound abatement material installed. They can be placed on crushed gravel without a foundation. The units are relatively efficient with a 9615 heat rate on 80%/20% gas/oil operation. Because of uncertainty around air permit limitations, either a 12-month lease or purchase are the financial options considered. The equipment has a 10% residual value at the end of the 12-month lease.

There are several scenarios under which these units might operate depending on the air permit process:

1. Operate 7/1/01 until whatever time the new 7MW CT begins operation at Kettle Falls (approximately 1/14/02) under a 12 month emergency temporary permit. This assumes that air permit studies show that we cannot operate the existing plant, the new 7MW CT and these 10.8MW bi-fuel generation units simultaneously and units cannot be moved to another site. Under this scenario, the 10.8MW units would be shut-down on 1/14/01.
2. Operate 7/1/01 until whatever time the new 7MW CT begins operation at Kettle Falls. When the new 7MW CT begins operation, move the 10.8MW bi-fuel generation to a location (tentatively we have identified Hallet & White substation) in Spokane County where emergency temporary permits can be obtained for limited 6 month periods. Operate through 6/30/02 at the second location.
3. Begin operation at Kettle Falls 7/1/01 under the emergency temporary permit. If air quality modeling for the new 7MW CT indicates that the existing plant, 7MW CT, and the 10.8MW

bi-fuel generation can all be operated simultaneously, then a permanent permit application will be filed such that the 10.8MW bi-fuel units can operate indefinately. In this scenario, the bi-fuel units will be left at Kettle Falls through 6/30/02.

Scenario #3 is the best case. Scenario #1 is the worst case. We have financially modeled both cases.

Issues associated with this generation include:

- **Air Permit** – These units would operate on a temporary (12-month) "emergency generation" permit basis up until the time when the new 7MW CT (which has already approved for Kettle Falls) will come on line (approximate on-line date 1/15/02). We expect a 30 day permit time-line under the governor's program. We will proceed with permitting the 7MW unit after we receive the emergency temporary permit for the 10.8MW generation. We will include in that modeling analysis one scenario where the existing generation plant, the 7MW turbine, as well as the 10.8 MW bi-fuel generation operate simultaneously. We will then evaluate whether it is reasonable to request a permanent permit for all three generation projects, or whether we will stop generation of the bi-fuel units at the Kettle Falls site at the time the 7MW CT comes on line. These units will have SCR emission control equipment added to control NOx and CO.

  [We are in the process of obtaining the air permit modeling for this project. Results are expected within the next week.]

- **Property** – All units will fit on the existing Kettle Falls site. Noise abatement measures are planned due to residences nearby.

- **Building Permit** – This generation comes in unit containers and will set directly on crushed gravel. We plan to build an additional 15,000 gallon oil storage tank to supplement the existing 10,000 gallon tank on site.

- **Electrical Interconnection** – Generation will come with transformers to step-up to 13.8KV and it is planned to integrate them into the distribution system at that voltage.

  [Engineering must give the final ok on the number of units at this site depending on some specific electrical parameters that relate to fault duty.]

- **Gas Supply** – There is natural gas available at Kettle Falls. A new gas regulator and additional gas lines are budgeted. As discussed above, capacity for natural gas may not be available on all days depending on downstream use (including NW Alloys use) as well as Kettle Falls plant use to augment wood fuel and the new 7MW CT natural gas useage.

- **Oil Storage** – As described above, we plan to have 25,000 gallons of storage capacity on-site. Additionally, each generation unit comes equipped with a 2400 gallon double wall tank. Therefore, we will have a total of 39,400 gallons of oil storage capability at Kettle Falls. This capacity provides for approximately 10 days of operation on 80%/20% gas/oil operation and 2 days of operation on 100% oil operation.

- **Financing** – These units could be either purchased or financed through a lease with US Bancorp. The equipment has a 10% residual value at the end of the lease and we would have an option to purchase the equipment at that value. [We received the form of the lease agreement on 3/23 and it has not been reviewed.]

- **Reliability** – Due to the small unit configuration, the company benefits from the diversification.

- **Economics** – The planned operation of these units is to provide a lower cost alternative, compared to purchasing firm power in the market to cover short-term deficiencies, variability in available power ~~form~~ from hydro projects, variability in loads and generation unit outage risk Doing so would reduce the electric deferral balance.

  The following information is based on the currrent forward market prices for both natural gas and electricity. Two scenarios have been prepared for the analysis. Scenario 1 assumes the generation is operational for 12 month period. Scenario 2 assumes the generation is operational for a 6 month period (although the lease payments continue for the full 12 months). Results of the analysis are as follows:

	Scenario 1 12 Month Operation (85,147 MWh)		Scenario 2 6 Month Operation (42,924 MWh)	
	$/MWh	Total Dollars	$/MWh	Total Dollars
Fixed Cost To Generate	$53	$4.5 million	$105	$4.5 million
Variable Cost To Generate	$86	$7.3 million	$88	$3.8 million
Total Cost To Generate	$139	$10.9 million	$192	$8.3 million
Ave. Flat Forward Market	$265	$21.7 million	$358	$15.4 million
Project Benefit	$127	$10.8 million	$166	$7.1 million

This economic analysis assumes a July 1st on-line date. It is likely that this generation can be put on line more quickly.

A revenue requirement analysis has also been performed showing a comparison of a 12 month operation under a 12 month lease arrangement and a purchase option that allows the units to operate over a 25 year life. The 12 month lease option shows a $11.9 million positive benefit while the purchase option shows a $11.3 million positive benefit.

The purchase option has greater benefits in year one and two when the spark spread between electricity and natural gas creates high positive benefits. Thereafter, the spark spread is not great enough to overcome the ongoing fixed costs of the project, even though it operates on a variable cost basis.

Comparatively, the lease option has less value in the first two years. However, this is probably a better match of the costs to the benefits of this project. The lease places most of the costs into the 12-month lease (which straddles a two year time period in the analysis). This is also when the greatest benefits to customers occur.

Cost of the 12 month lease including emission equipment is $348,641/month. Additional sound abatement costs may be added to this.

Cost of the generation equipment including emission equipment is $4,402,588 not including tax. Cost to purchase the generation equipment plus tax, installation, and sound abatement is estimated at $5,054,000

Cash Flow Analysis
10.8MW Bi-Fuel Reciprocating Generation
1 Year Lease with No Purchase At Termination - 12 Month Operation

Capacity 10.8
Heat Rate 9616 (80% gas/20% Oil)

	Total	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
[redacted]	[redacted]	744	720	744	720	744	744	720	744	720
[redacted]	[redacted]									
[redacted]	[redacted]					$ 348,641	$ 348,641	$ 348,641	$ 348,641	$ 348,641
[redacted]	[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	$ -	$ 125,000	$ 185,000	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	$ -	$ -	$ -	$ -	$ 479,494	$ 481,232	$ 464,026	$ 509,051	$ 537,624
[redacted]	[redacted]					$ 122,939	$ 122,939	$ 118,973	$ 122,939	$ 118,973
[redacted]	[redacted]	$ -	$ 125,000	$ 185,000	$ -	$ 951,073	$ 952,812	$ 931,640	$ 980,630	$ 1,005,238
[redacted]	[redacted]									
Total Generation MWh @ 90% LF	[redacted]					7,232	7,232	6,998	7,232	6,998
Total Costs/MWh @ 90% LF						$ 131.51	$ 131.76	$ 133.12	$ 135.60	$ 143.64
[redacted]	[redacted]									
[redacted]	[redacted]					$ 388.00	$ 422.00	$ 391.00	$ 322.00	$ 284.00
[redacted]	[redacted]					$ 256.49	$ 290.24	$ 257.88	$ 186.40	$ 140.36
[redacted]	[redacted]	$ -	$(125,000)	$(185,000)	$ -	1,854,818	2,098,957	1,804,735	1,347,971	982,308
Support										
Pre-Lease Costs	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Fixed Costs	310,000	$ -	$ 125,000	$ 185,000	$ -	$ -	$ -	$ -	$ -	$ -
Property Acquisition			$ -							
Air Permitting Costs			$ 10,000	$ 10,000						
Building Costs (Building and Pads)			$ -	$ 15,000						
Building Permit Costs			$ 5,000							
Gas Regulator Installation			$ -	$ 85,000						
Substation Extension			$ 75,000	$ 75,000						
Oil Tank			$ 35,000							
Nat Gas Costs										
MMBtu Consumed/Month						57,955	57,955	56,085	57,955	-
Cost of Delivered Gas/MMBtu						$ 6.14	$ 6.17	$ 6.14	$ 6.65	$ 7.18
Avista Gas Transportation ($/dth)						$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21
Total Gas Cost/Month	$ 2,822,696					$ 367,961	$ 369,699	$ 358,091	$ 397,518	$ -
Oil Costs										
Gallons Consumed/Month						111,533	111,533	107,935	111,533	537,624
Cost of Oil/Gallon						$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Cost of Oil/MMBTU						$ 7.69	$ 7.69	$ 7.69	$ 7.69	$ 7.69
Total Oil Cost/Month	$ 3,031,967					$ 111,533	$ 111,533	$ 107,935	$ 111,533	$ 537,624
Total Fuel Cost/Month						$ 479,494	$ 481,232	$ 464,026	$ 509,051	$ 537,624

	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02
[redacted]	744	744	672	744	720	744	720	744	744
[redacted]									
[redacted]	$ 348,641	$ 348,641	$ 348,641	$ 348,641	$ 348,641	$ 348,641	$ 348,641	$ -	$ -
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	$ 555,545	$ 555,545	$ 501,782	$ 516,005	$ 416,915	$ 425,016	$ 412,428	$ -	$ -
[redacted]	$ 122,939	$ 122,939	$ 111,041	$ 122,939	$ 118,973	$ 122,939	$ 118,973	$ -	$ -
[redacted]	$ 1,027,124	$ 1,027,124	$ 961,465	$ 987,585	$ 884,528	$ 898,596	$ 880,041	$ -	$ -
[redacted]									
Total Generation MWh @ 90% LF	7,232	7,232	6,532	7,232	6,998	7,232	6,998	-	-
Total Costs/MWh @ 90% LF	$ 142.03	$ 142.03	$ 147.20	$ 136.56	$ 126.39	$ 123.96	$ 125.76	#DIV/0!	#DIV/0!
[redacted]									
[redacted]	$ 291.00	$ 252.00	$ 225.00	$ 198.00	$ 134.00	$ 129.00	$ 139.00	$ 184.00	$ 190.00
[redacted]	$ 148.97	$ 109.97	$ 77.80	$ 61.44	$ 7.61	$ 5.02	$ 13.25	#DIV/0!	#DIV/0!
[redacted]	1,077,295	795,259	508,199	444,288	53,257	38,291	92,736	#DIV/0!	#DIV/0!
Support									
Pre-Lease Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Fixed Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nat Gas Costs									
MMBtu Consumed/Month	-	-	-	57,955	56,085	57,955	56,085	-	-
Cost of Delivered Gas/MMBtu	$ 7.29	$ 7.31	$ 7.10	$ 6.77	$ 5.30	$ 5.20	$ 5.22	$ 5.27	$ 5.28
Avista Gas Transportation ($/dth)	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21	$ 0.21		
Total Gas Cost/Month	$ -	$ -	$ -	$ 404,472	$ 308,979	$ 313,483	$ 304,493	$ -	$ -
Oil Costs									
Gallons Consumed/Month	555,545	555,545	501,782	111,533	107,935	111,533	107,935		
Cost of Oil/Gallon	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00		
Cost of Oil/MMBTU	$ 7.69	$ 7.69	$ 7.22	$ 7.22	$ 7.22	$ 7.22	$ 7.22		
Total Oil Cost/Month	$ 555,545	$ 555,545	$ 501,782	$ 111,533	$ 107,935	$ 111,533	$ 107,935		
Total Fuel Cost/Month	$ 555,545	$ 555,545	$ 501,782	$ 516,005	$ 416,915	$ 425,016	$ 412,428		

10.8 MW Bi-Fuel Fired Recips -- Online July 2001 -- Lease Option

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	318	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	10.00	2001$/MWh
Project Capacity	10.8	MW	Fixed O&M	0.46	2003$ per kW-month			
Heat Rate	9,615	Btu/kWh	Escalation Rates			Insurance Cost	0.93	0.3% of installed cost ($000s)
Peak Gas Usage	2,492	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00	2000 $/dth
			Variable O&M	2.5	percent	Electric Wheeling	0	$/MW-month thru 2006
			Transportation	2.5	percent	General Inflation	2.5	percent

Electric Wheeling Losses	0.0	percent
Nominal Discount Rate	7.77	percent
Real Discount Rate	5.1	percent
IRR		
Profitability Index	38.48	

Year		Energy (GWh)	Fixed Costs: Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Lease Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
1	2001	45.3	323	0	323	7.1	56	0	0	4	1	61	1.3	384	384	8.5	10,346	9,961	219.9	3,120	2,545	5,665	125.0	6,049	133.5
2	2002	44.6	309	0	309	6.9	57	0	0	4	1	62	1.4	371	371	8.3	3,463	3,111	69.8	2,866	2,538	5,404	121.2	5,775	129.5
3	2003	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
4	2004	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
5	2005	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
6	2006	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
7	2007	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
8	2008	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
9	2009	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
10	2010	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
11	2011	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
12	2012	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
13	2013	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
14	2014	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
15	2015	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
16	2016	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
17	2017	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
18	2018	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
19	2019	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
20	2020	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
21	2021	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
22	2022	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
23	2023	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
24	2024	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
25	2025	0.0	0	0	0	#DIV/0!	0	0	0	(0)	0	(0)	#DIV/0!	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	(0)	#DIV/0!
2001$																									
Net Present Value			586	0	586		100	0	0	5	2	107		673	673		12,596	11,922		5,363	4,546	9,909		10,583	
Nominal Levelized Cost ($/MWh)						7.0							1.3			8.4			148.3				123.3		131.6
Real Levelized Cost ($/MWh)						6.8							1.3			8.1			143.8				118.8		126.9

AVISTA UTILITIES

04-07-2001 10.8 MW Bi Fuel 2001 Lease Economics.xls ogh

Exhibit No.___ (KON-4)
Case No. AVU-E-____
Page 5 of 10

AVISTA
Corporation

Energy Resources

Devil's Gap Temporary Diesel Generation Proposal
Prepared by Jason Thackston
4/4/01

Situation

Although the company has worked hard to balance the utility's load and resource positions, there are conditions that require additional short-term supplies of power. It is prudent for us to protect ourselves from short-term deficiencies, variability in available power from hydro projects, variability in loads, and generation unit outage risk given the high prices and volatility evident in the competitive electric power market. Building additional generation suitable for economic short-term supply is one such way to obtain that protection. While the Boulder Park generation, if completed, will add 50.7 megawatts of capacity by mid-July, there is a need for additional generation in the short-term. Given the potential emissions challenges at Boulder Park, it is even more prudent to pursue additional generation.

Devil's Gap Generation

We have received a proposal for 20 megawatts of diesel generation to be sited near the Devil's Gap substation in Lincoln County. The generation consists of 20 one-megawatt containerized diesel units. Natural gas is not available in the region, so any generation in that area needs to be fueled by alternative sources such as diesel. Issues include:

- **Alternatives to Project** – Avista continues to assess short-term supply through other temporary generation, customer load buy-backs, market purchases, and financial options. The economic analysis for the short-term compares the benefits of the project to the most liquid and available alternative, the over-the-counter energy market. Financial options are unavailable in the marketplace due to the dramatically increased volatility in the market and are not a viable alternative.
- **Air Permit** – Given the short-term nature of this project (the offer contains a one-year rental contract), a temporary one-year permit would be pursued. This generation will be equipped with adequate emissions controls. Permitting will be complete before this generation is available for operation.
- **Property** – Avista owns the property near the substation.
- **Electrical Interconnection** – 20 megawatts can be integrated into Devil's Gap with a spare transformer and spare power circuit breaker, both owned by Avista.
- **Diesel Supply** – Avista has received a quote for diesel delivered to the site – fuel is readily available and could be procured for the one-year period of time.
- **Financing** – Aggreko has directly offered a monthly rental amount for one year. Monthly payments to Aggreko are projected to be about $900,000.
- **Reliability** – Given the multiple units, the risk of losing all 20 megawatts is minimal. Reliability is therefore greater than a single 20 megawatt unit.
- **Efficiency** – The heat rate is calculated to be 10,712.

- **Economics** – Because this generation would be used to protect against unit outages and peaking loads, the output of this generation would not be pre-sold into the market. However, on a short-term basis, as loads and resources permit, the generation could be sold into the market when economics support the transaction. Doing so would be prudent as it reduces the electric deferral balance.

  The following information is based on forward market prices for both diesel and electricity as of this last week. Given the one-year offer from Aggreko, only one scenario has been evaluated – all costs of the project are incurred over the year and the equipment is returned at the end of the period. Results of the analysis are summarized below and detailed in Attachment A:

	Generation @ 92% Availability (161,184 MWh)	
	$/MWh	**Total Dollars**
Fixed Cost to Generate	$ 70.99	$ 11.4 million
Variable Cost to Generate	91.17	14.7 million
Total Cost to Generate	162.16	26.1 million
Increased Revenue or Decreased Expense	283.10	45.6 million
Project Benefit	**$ 120.94**	**$ 19.5 Million**

  This project is beneficial to the system over the next year and is considered a strong alternative to other short-term energy sources. The generation is not intended to be a longer-term solution to Avista's resource needs but fits well into the short-term resource needs for the coming summer and winter. A revenue requirement model was not run on the project, as this has no long-term benefits to the customer. It is assumed that the deferral balance would incorporate the operating costs (including the rent/lease), as the resulting net increased sales or net decreased purchases positively impact the deferral balance in the magnitude listed above.

The analysis of this project assumes an operational date of July 1.

Jason Thackston
April 2, 2001

Cash Flow Analysis
20MW Aggreko Diese ation
1 Year Lease

Capacity	20.0	MW
Heat Rate	10,712	
Load Factor	92%	
Variable Costs/MWh	$ 14.00	
Lease Rate	$ 907,000	

	Totals	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
Hours in Month	7,272					744	744	720	744	720	744	744	672	744	720	744	720
[redacted]	[redacted]					$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000	$ 907,000
[redacted]	[redacted]					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	$ -	$ -	$ 557,796	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]					$ 1,056,480	$ 1,056,480	$ 1,022,400	$ 1,056,480	$ 1,022,400	$ 1,056,480	$ 1,056,480	$ 954,240	$ 1,056,480	$ 1,022,400	$ 1,056,480	$ 1,022,400
[redacted]	[redacted]					$ 191,654	$ 191,654	$ 185,472	$ 191,654	$ 185,472	$ 191,654	$ 191,654	$ 173,107	$ 191,654	$ 185,472	$ 191,654	$ 185,472
[redacted]	[redacted]			$ 557,796		$ 2,155,134	$ 2,155,134	$ 2,114,872	$ 2,155,134	$ 2,114,872	$ 2,155,134	$ 2,155,134	$ 2,034,347	$ 2,155,134	$ 2,114,872	$ 2,155,134	$ 2,114,872
Total Generation @ 92% Load Factor	161,184					13,688.60	13,689.60	13,248.00	13,689.60	13,248.00	13,689.60	13,689.60	12,364.80	13,689.60	13,248.00	13,689.60	13,248.00
Total Revenue or Reduced Expense	$ 45,725,574					$ 5,764,554	$ 6,231,917	$ 5,578,800	$ 4,375,333	$ 3,744,150	$ 3,920,975	$ 3,752,182	$ 3,025,543	$ 3,025,128	$ 1,978,854	$ 1,941,048	$ 2,387,290
Total Costs/MWh @ 92% Load Factor						$ 157.43	$ 157.43	$ 159.84	$ 157.43	$ 159.64	$ 157.43	$ 157.43	$ 164.53	$ 157.43	$ 159.64	$ 157.43	$ 159.64
[redacted]	[redacted]																
[redacted]	[redacted]					$ 421.09	$ 455.23	$ 421.09	$ 319.81	$ 282.62	$ 286.42	$ 274.09	$ 244.69	$ 220.98	$ 149.37	$ 141.79	$ 180.20
[redacted]	[redacted]					$ 263.66	$ 297.80	$ 261.45	$ 162.18	$ 122.98	$ 128.99	$ 116.66	$ 80.16	$ 63.55	$ (10.27)	$ (15.64)	$ 20.56
[redacted]	[redacted]			$ (557,796)		$ 3,809,419	$ 4,076,782	$ 3,463,728	$ 2,220,199	$ 1,829,278	$ 1,765,841	$ 1,597,048	$ 991,196	$ 869,993	$ (136,018)	$ (214,086)	$ 272,418

Support

	Totals	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
Pre-Lease Costs	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest on Project Costs																	
		$ -	$ -	$ -	$ -												
Fixed Costs	$ 557,796		$ -	$ 557,796	$ -	$ -	$ -	$ -	$ -								
Turbine	$ -		$ -	$ -	$ -				$ -								
Siting	$ 120,000		$ -	$ 120,000	$												
Interconnection	$ 385,000			$ 385,000	$ S/B 220,000	$ -	$ -	$ -									
Construction	$ 11,000			$ 11,000	$ -	$ -	$ -	$ -									
Sales Tax (8.1% on everything - Max amount)	$ 41,796		$ -	$ 41,796	$ -	$ -	$ -	$ -	$ -								

Fuel Costs

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
Gallons/Hour	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00	1,420.00
Total Gallons/Month	1,056,480	1,056,480	1,022,400	1,056,480	1,022,400	1,056,480	1,056,480	954,240	1,056,480	1,022,400	1,056,480	1,022,400
Diesel Cost/Gallon	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Fuel Cost	$1,056,480.00	$1,056,480.00	$1,022,400.00	$1,056,480.00	$1,022,400.00	$1,056,480.00	$1,056,480.00	$954,240.00	$1,056,480.00	$1,022,400.00	$1,056,480.00	$1,022,400.00
Cost of fuel/MMBtu	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20	$ 7.20
Total MMBtu Consumed per m	146,639	146,639	141,909	146,639	141,909	146,639	146,639	132,449	146,639	141,909	146,639	141,909
Heat Rate	10,712	10,712	10,712	10,712	10,712	10,712	10,712	10,712	10,712	10,712	10,712	10,712
Cost/MWh	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17	$ 77.17

Exhibit No.___ (KON-4)
Case No. AVU-E-____
Page 8 of 10

Avista Corp.
Small Generation Analysis
June 19, 2001

Project	Capacity	Terms	Operational	Total Project Costs (Capital & Lease)	Estimated Fixed/MWh		Estimated Variable/MWh***	Original Project Benefit Date Calculated	Original Project Benefit Dollar Benefit	6/4/01 Value	6/11/01 Value
Devil's Gap	20MW	Leased 12 Months	07-01-01	$11.7mm	$ 73.00		$ 90.00	04-04-2001	$19.5 million	($5.2 million)	($6.1 million)
Kettle Falls Bi-Fuels	10MW	Leased 12 Months	07-13-01	$4.4mm	$ 122.00 $ 56.00	(5 Mths) (11 Mths)	$ 73.00	05-10-2001	$4.1 million	$1.3 million	($203 thousand)
Othello CT	23MW	Purchased	10-01-01	$19.0mm	$ 15.26		$ 90.00	04-02-2001	($240 thousand) - 25 yrs	($15.6 million)	($25.5 million)
Boulder Park	25MW	Purchased	09-01-01	$21.0mm	$ 14.42		$ 50.00	05-18-2001	$11.0 million - 25 yrs	($5.8 million)	($10.9 million)
SIP	8MW	Purchased	09-01-01	$8.5mm	$ 24.84		$ 50.00	05-18-2001	($360 thousand) - 25 yrs	($4.2 million)	($6.0 million)

Project	Strike	Theoretical Option Value Premium/MWh*	Theoretical Option Value Total Premium**	Estimated Exit and Sunk Costs
Devil's Gap	$ 90	$ 38	$6.6 million	$11.7 million
Kettle Falls Bi-Fuels	$ 73	$ 55	$2.0 million	$2.6 million
Othello CT	$ 90	$ 39	$7.9 million	$2.8 million
Boulder Park	$ 50	$ 50	$10.8 million	$10.2 million
SIP	$ 50	$ 50	$3.5 million	$2.8 million

*Premium calculation is an average of monthly premiums based on a daily call option beginning July 1, (for Devil's Gap/Kettle Falls) September 1 (for Boulder/SIP), and October 1 (for Othello).
Volatility is assumed to be 175% compared to a flat market in each month.
**Total Premium is calculated by multiplying capacity and 12 months (5 months for Kettle Falls)
***Variable cost calculated using $1.00/gallon diesel and $5.00/MMBtu natural gas.

CONFIDENTIAL
June 19, 2001
Jason Thackston

Avista Corp
Small Generation - Option Premium vs. Cost to Complete
June 19, 2001 Analysis

	Original Project Total Cost	Committed Cost (or cost to terminate)	Cost to Complete	1-Year Option Premium Value	Net Benefit of Project Compared to 1-Year Option Value
Boulder Park	$ 21.00	$ 10.20	$ 10.80	$ 10.80	$ -
SIP	$ 8.50	$ 2.80	$ 5.70	$ 3.50	$ (2.20)
K Falls	$ 4.40	$ 2.60	$ 1.80	$ 2.00	$ 0.20
Devils Gap	$ 11.70	$ 11.70	$ -	$ 6.60	$ 6.60
Othello	$ 19.00	$ 2.80	$ 16.20	$ 7.90	$ (8.30)

Note: All $ amounts in millions

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (KON-5) OF KELLY O. NORWOOD

REPRESENTING AVISTA CORPORATION

Exhibit KON-5

IDAHO PCA
POTLATCH CONTRACT CHANGE ANALYSIS
January - June 2002

		Total Jan 02 - Jun 02	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02
Actual Less Authorized System								
Potlatch Co-Gen Acct 555		(9,984,904)	(2,169,820)	(1,954,073)	(1,664,649)	(1,668,875)	(1,479,117)	(1,048,370)
Potlatch 25 aMW Direct Assignment		(3,257,250)	(558,000)	(504,000)	(558,000)	(539,250)	(558,000)	(540,000)
Idaho Jurisdictional Allocation	33.18%							
Potlatch Co-Gen Acct 555		(3,312,991)	(719,946)	(648,361)	(552,331)	(553,733)	(490,771)	(347,849)
Potlatch 25 aMW Direct Assignment Credit		(1,080,754)	(185,144)	(167,227)	(185,144)	(178,923)	(185,144)	(179,172)
Potlatch 25 aMW Direct Assignment		3,257,250	558,000	504,000	558,000	539,250	558,000	540,000
Potlatch Allocated Revenue Credit		3,512,771	627,322	613,757	622,727	560,494	577,654	510,817
Potlatch Direct Revenue Credit		(3,893,543)	(583,018)	(470,973)	(628,429)	(673,040)	(693,652)	(844,431)
Idaho Total Potlatch Impact		(1,517,267)	(302,786)	(168,804)	(185,177)	(305,952)	(233,913)	(320,635)
Customer Share	90%	(1,365,540)	(272,507)	(151,924)	(166,659)	(275,357)	(210,522)	(288,572)

Note: Revenues are shown by the impact to the deferral, for example, a positive revenue credit decreasing the deferral is shown as a negative number.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-______

DIRECT TESTIMONY OF RONALD L. MCKENZIE

REPRESENTING AVISTA CORPORATION

Q. Please state your name, the name of your employer and your business address.

A. My name is Ronald L. McKenzie. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am employed by Avista as Manager of Regulatory Accounting in the Rates and Regulation Department.

Q. Please state your educational background and professional experience.

A. I graduated from Eastern Washington University in 1973 with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in September 1974. I obtained a Master of Business Administration Degree from Eastern Washington University in 1989. I have attended several utility accounting and ratemaking courses and workshops. I have held various accounting positions within the Company. I have served in the Rates Department for the majority of my career with the Company.

Q. What is the scope of your testimony in this proceeding?

A. My testimony provides a status report of the accounting entries and account balances related to the Idaho Power Cost Adjustment (PCA) for the twelve months ended June 30, 2002. The unrecovered deferral balance at June 30, 2002 is $45,600,228. I explain how the Company has complied with the Commission's last order related to the Centralia capital and O&M credit and the method of calculating interest. I explain that the PGE contract credit will be fully amortized at the end of 2002 and the resulting PGE contract related revenues that will be reflected in the PCA calculations beginning January 1, 2003. I explain that a Customer Notice was issued and that if the Company's proposal to extend the surcharge is approved, there would be no change to the existing PCA tariff, Schedule 66. In addition, I address the Company's request to increase the carrying charge rate that is applied to the net deferral balance.

Q. Are you sponsoring an Exhibit?

A. Yes. I am sponsoring Exhibit No. ___ (RLM-1), consisting of two pages.

Q. What amount of the deferral balance at June 30, 2002 remains to be recovered?

A. The amount of unrecovered deferral balance at June 30, 2002 is $45,600,228 as shown below:

Deferral, Account 186.38	$60,723,493
Accumulated amortization, Account 186.39	-15,123,265
Unrecovered balance at June 30, 2002	$45,600,228

Q. Would you please describe the accounting entries and account balances related to the PCA deferral account?

A. Yes. The PCA deferral account balance, Account 186.38, at June 30, 2001 was $30,007,057, the actual amount of power costs authorized for recovery at page 11 of the Commission's Order No. 28876 in Case No. AVU-E-01-11 dated October 12, 2001. Listed below is a summary of the major components of the deferral account entries that were recorded for the twelve-month period July 2001 through June 2002 together with the deferral account balances at the beginning and end of the twelve-month period:

Deferral balance at June 30, 2001	$30,007,057
Deferrals July 2001 through June 2002	48,442,371
Transfer of under-rebate	-49,073
Transfer of under-surcharge	342,069
PGE monetization accelerated amortization	-20,783,521
Interest	2,764,590
Subtotal – Account 186.38 balance at June 30, 2002	60,723,493
Revenues collected October 12, 2001 – June 30, 2002	-15,123,265
Unrecovered balance at June 30, 2002	$45,600,228

Q. Would you please explain the components listed above?

A. Yes. The deferrals of $48,442,371 represent the Idaho jurisdictional share of 90% of the excess power costs incurred by Avista for the twelve months ended June 30, 2002. Mr. Norwood discusses the components that make up this amount. The remaining 10% of the excess power costs were absorbed by the Company.

The transfer to the deferral account of the under-rebated amount of -$49,073 relates to the $2,363,500 rebate effective August 1, 2000 that expired on July 31, 2001. The amount actually rebated to customers during that twelve-month period was $2,314,427. The effect of this accounting entry is to reduce the deferral balance by $49,073.

The transfer of the under-surcharged amount of $342,069 relates to the $5,707,635 surcharge effective February 1, 2001 that was accounted for in miscellaneous accounts receivable, Account 142.38. The surcharge was originally set to expire on January 31, 2002, but was extended by Order No. 28876 to expire on October 11, 2002. The amount actually surcharged to customers during the twelve-month period February 1, 2001 through January 31, 2002 was $5,365,566 and was accounted for through amortization entries as credits to Account 142.38. The remaining balance of $342,069 in Account 142.38 was transferred to the deferral account, Account 186.38 in January 2002 for later recovery. Subsequent to January 2002, the extended surcharge revenues were accounted for by crediting accumulated deferral amortization, Account 186.39.

The -$20,783,521 figure relates to the amount of accelerated amortization of the Portland General Electric (PGE) contract credit balance for the months of October 2001 through June 2002. The Commission authorized the accelerated amortization at page 12 of Order No. 28876. The normal amortization and the accelerated amortization of the PGE contract credit balance will end December 31, 2002. Beginning January 2003, the PGE contract related revenues reflected in the PCA calculations will be the actual revenues received from PGE, and will no longer include additional adjustments.

The $2,764,590 interest amount represents interest for the twelve-month period July 1, 2001 through June 30, 2002 as well as an adjustment for the first six months of 2001. In October 2001, interest was adjusted for the months of January through June 2001 and the months of July through September 2001 to comply with Order No. 28876 at page 13. In compliance with the Order, interest has been calculated using the customer deposit rate applied to the month-end deferral balance prior to the month that interest is being calculated with no compounding of interest.

Q. Has the Company complied with applying 100% rather than 90% of the Centralia capital and O&M credit in the deferral calculation?

A. Yes. The Centralia capital and O&M credit is addressed at page 9 of Order No. 28876. In July 2001 the Company began applying 100% of the Centralia credit as a deferral offset and an adjustment was recorded for the difference between 100% of the credit and the 90% of the credit that had been recorded for the months of January through June 2001.

Q. How much PCA revenue was rebated and surcharged during the twelve-month period of July 1, 2001 through June 30, 2002?

A. There was $161,270 of PCA rebate and $18,238,963 of PCA surcharge during the twelve-month period of July 1, 2001 through June 30, 2002. An amount of $161,270 of PCA rebate amortization was charged to the August 1, 2000 rebate deferral balance, Account 242.11. Of the $18,238,963 amount of PCA surcharge, an amortization of $3,115,698 was credited to the February 1, 2001 surcharge deferral balance, Account 142.38, and an amortization of $15,123,265 was credited as an offset to the deferral balance in Account 186.39.

Q. Was a notice supplied to customers regarding the Company's proposal to continue the existing PCA surcharge for an additional twelve months?

A. Yes. Page 1 of Exhibit No. ___ (RLM-1) is a copy of the notice that was provided as a bill insert to Idaho electric customers beginning August 12, 2002. The notice indicates that the Company has filed a request with the Commission to continue the existing 19.4% surcharge for an additional twelve months. The existing surcharge amounts to approximately $23.6 million on an annual basis.

Q. If the Company's proposal to extend the surcharge is approved, would it require a change to the current PCA tariff, Schedule 66?

A. No. In fact, the Company is proposing that the current Schedule 66 remain in place as currently on file. The existing Schedule 66 contains the currently effective surcharge rates that the Company is requesting be extended for an additional twelve months. Under the Special Terms and Conditions on the tariff is a statement that, "The rates set forth under this Schedule are subject to periodic review and adjustment by the IPUC based on the actual balance of deferred power costs." Page 2 of Exhibit No. ___ (RLM-1) is a copy of Schedule 66.

Q. Would you please describe the Company's request for an increase in the carrying charge that is applied to the unrecovered deferral balance?

A. Yes. The carrying charge rate applied to the unrecovered deferral balance is the customer deposit rate. The current rate is 4% in 2002. The Company believes that a more realistic carrying cost is the Company's actual weighted cost of debt, which at June 30, 2002 was 8.88%. The deferral balance is being recovered over multiple years and the Company has issued long-term debt to finance the deferral balance.

Q. Is recovery of the deferral balance over multiple years different than the time period for the recovery or rebate of deferral balances in the past?

A. Yes. In the past, PCA rebates and surcharges have been for twelve month periods. The combination of poor hydro conditions and unprecedented high wholesale market prices have led to both a higher than normal PCA surcharge of 19.4% as well as recovery of the deferral balance over multiple years.

Q. Has the Commission previously approved a carrying charge rate for Idaho Power Company that recognizes recovery of power costs deferred beyond one year?

A. Yes. Order No. 29026 in Case Nos. IPC-E-02-2 and IPC-E-02-3 issued May 13, 2002 at page 19 authorizes a carrying charge rate of 6% for Idaho Power Company for power costs that are deferred for recovery beyond one year.

Q. Would the carrying charge rate of 6% be acceptable to the Company?

A. A carrying charge rate of 6% would be more representative of the true cost of financing the deferred power costs. In this particular case, we believe a higher carrying cost is justified since the deferred power costs will be recovered over multiple years.

Q. Is the Company proposing that the higher carrying cost be temporary or permanent?

A. The Company is proposing that the higher carrying cost be allowed until the multi-year recovery of the deferral balance ends. The carrying cost could then revert back to the customer deposit rate.

Q. Does that conclude your testimony?

A. Yes it does.

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. AVU-E-_____

EXHIBIT NO. ___ (RLM-1)

WITNESS: RONALD L. MCKENZIE, AVISTA CORPORATION

Important Notice for Idaho Electric Customers

August/September 2002

Avista has filed with the Idaho Public Utilities Commission (IPUC) a request to continue the existing Power Cost Adjustment (PCA) electric surcharge of 19.4% for an additional twelve months. **If the request is approved, there would be no change to your existing electric rates; they will remain the same as they are now.**

Last fall, the IPUC approved a 19.4% electric surcharge for each major customer class to expire on October 11, 2002. On an annual basis the surcharge amounts to approximately $23.6 million. The IPUC directed Avista to file a status report to support continuation of the 19.4% surcharge. Avista has filed the status report and is requesting that the 19.4% surcharge be extended until October 11, 2003 to recover excess power costs that the Company has experienced to serve its customers. Avista makes no profit from surcharge revenues and actually is required to absorb 10% of excess power costs.

The PCA mechanism was originally approved by the IPUC in 1989. The mechanism allows the Company to surcharge or rebate changes in costs to customers on a temporary basis based on the difference between actual power supply costs and the level of those costs reflected in base retail rates.

Avista's request to extend the electric surcharge is a proposal, subject to public review and a decision by the IPUC. A copy of the Company's application is available for public review at the offices of both the IPUC and the Company. A copy of the application is also available on our website at www.avistautilities.com under "Energy Prices", "Rates and Tariffs".

If you would like information on energy conservation tips, energy assistance programs, and bill payment plans, visit our website at www.avistautilities.com, or call us at 1-800-227-9187.

AVISTA
Utilities

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SCHEDULE 66

TEMPORARY POWER COST ADJUSTMENT - IDAHO

APPLICABLE:
To Customers in the State of Idaho where the Company has electric service available. This Power Cost Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover or rebate a portion of the difference between actual and allowed net power supply costs.

MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:

Schedule 1	
0 – 600 kwhs	0.939¢ per kwh
over 600 kwhs	1.092¢ per kwh
Schedules 11 & 12	1.391¢ per kwh
Schedules 21 & 22	1.011¢ per kwh
Schedules 25	0.607¢ per kwh
Schedules 31 & 32	0.888¢ per kwh

Flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service are to be increased (decreased) by the following percentage:

Schedules 41-49	19.37%

SPECIAL TERMS AND CONDITIONS:

The rates set forth under this Schedule are subject to periodic review and adjustment by the IPUC based on the actual balance of deferred power costs.

Service under this schedule is subject to the Rules and Regulations contained in this tariff.

The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have served Avista Corporation's filing related to the Company's submission of a status report and request for the continuation of a PCA Surcharge in retail electric rates, by mailing a copy via overnight mail thereof, postage prepaid to the following:

Ms Jean D Jewell, Secretary
Idaho Public Utilities Commission
PO Box 83702
West 472 Washington
Boise, ID 83720-5983

Bill Nicholson
Potlatch Corporation
244 California Street
Suite 610
San Francisco, CA 94111

Conley Ward
Givens Pursley, LLP
277 North 6th Street, Suite 200
P.O. Box 2720
Boise, ID 83701

Dated at Spokane, Washington this 8th day of August 2002.

Patty Olsness

Patty Olsness
Rates Coordinator

AVISTA Corp.

News Release

Contact: Media: Catherine Markson (509) 495-2916 catherine.markson@avistacorp.com

FOR RELEASE:
August 9, 2002
8 a.m. EST

Avista Files to Extend Current Power Cost Adjustment Surcharge in Idaho

Existing electric rates for Idaho customers would not change

Spokane, Wash.: Avista Corp. (**NYSE:AVA**) has filed with the Idaho Public Utilities Commission (IPUC) a request to continue the existing power cost adjustment (PCA) electric surcharge of 19.4 percent for an additional twelve months. If approved, there would be no change to existing electric rates.

Last fall, the IPUC approved the current PCA that is set to expire on Oct. 11, 2002. At the time of the approval, the commission directed Avista to file a status report related to continuing the 19.4 percent surcharge beyond the expiration date. Avista has filed that status report and is requesting the surcharge be extended until Oct. 11, 2003, in order to continue recovering excess power costs that Avista has incurred to serve its customers.

Avista makes no profit from surcharge revenues and is required to absorb the first 10 percent of excess power costs. The PCA rate adjustment mechanism is designed to recover or rebate changes in certain power supply costs that differ from those costs included in Avista's base rates.

"The extension of the PCA in Idaho would allow the company to continue recovery of wholesale power costs while offering our customers some of the lowest residential electric rates in the country," said Kelly Norwood, vice president of rates and regulation.

Avista's request to extend the electric surcharge is a proposal, subject to both public review and a decision by the IPUC. A copy of Avista's application is available for review at the offices of both the IPUC and the company. A copy of the application is also available on the Avista Utilities website at www.avistautilities.com/prices/rates.

For more information on conservation tips, energy assistance programs, and bill payment plans, visit the Avista Utilities website at www.avistautilities.com, or call 1-800-227-9187.

–more–

Avista Corp. is an energy company involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is a company operating division that provides electric and natural gas service to customers in four western states. Avista's non-regulated affiliates include Avista Advantage, Avista Energy and Avista Labs. Avista Corp.'s stock is traded under the ticker symbol "AVA" and its Internet address is www.avistacorp.com.

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Important Notice for Idaho Electric Customers

August/September 2002

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Last fall, the IPUC approved a 19.4% electric surcharge for each major customer class to expire on October 11, 2002. On an annual basis the surcharge amounts to approximately $23.6 million. The IPUC directed Avista to file a status report to support continuation of the 19.4% surcharge. Avista has filed the status report and is requesting that the 19.4% surcharge be extended until October 11, 2003 to recover excess power costs that the Company has experienced to serve its customers. Avista makes no profit from surcharge revenues and actually is required to absorb 10% of excess power costs.

The PCA mechanism was originally approved by the IPUC in 1989. The mechanism allows the Company to surcharge or rebate changes in costs to customers on a temporary basis based on the difference between actual power supply costs and the level of those costs reflected in base retail rates.

Avista's request to extend the electric surcharge is a proposal, subject to public review and a decision by the IPUC. A copy of the Company's application is available for public review at the offices of both the IPUC and the Company. A copy of the application is also available on our website at www.avistautilities.com under "Energy Prices", "Rates and Tariffs".

If you would like information on energy conservation tips, energy assistance programs, and bill payment plans, visit our website at www.avistautilities.com, or call us at 1-800-227-9187.

AVISTA Utilities

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