BEFORE THE WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DOCKET NO. UE-

DIRECT TESTIMONY OF BRUCE W. FOLSOM
REPRESENTING AVISTA CORPORATION

Exhibit T-___(BWF-T)

I. INTRODUCTION

Q. Please state your name, business address, and present position with the Avista Corporation?

A. My name is Bruce W. Folsom. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by the Avista Corporation (Avista or Company) as a Regulatory Analyst.

Q. Would you please describe your education and business experience?

A. I graduated from the University of Washington in 1979 with Bachelor of Arts and Bachelor of Science degrees. I received a Masters in Business Administration degree from Seattle University in 1984. I have completed several rate making and regulatory courses and seminars.

I have been an analyst in Avista's Rates and Regulation Department since 1993 working on tariff filings and special projects such as energy efficiency funding, programs responsive to industry restructuring, low-income assistance programs, rulemakings and other emerging issues. Starting in 1984, I was employed by the Washington Utilities and Transportation Commission and held the position of Electric Program Manager from 1990 to February 1993. From 1979 through 1983, I was the Pacific Northwest Regional Director of what is now the Environmental Careers Organization, a national, private, non-profit organization.

Q. Have you previously testified before this Commission?

A. Yes. I have testified as an expert witness before this Commission in over 20 dockets.

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

A. I present testimony on two topics. First, I will provide documentation, as required by previous Commission guidelines, showing that Avista's expenditures for the Company's energy efficiency programs funded under the DSM Tariff Rider have been prudently incurred. Second, I address updated rates for two miscellaneous fees—reconnection charges and insufficient check fees—and propose a new late payment charge.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. __ (BWF-1) and __ (BWF-2), as previously marked for identification, which were prepared under my supervision and direction.

II. DEMAND-SIDE MANAGEMENT (DSM)

Q. What is the Company requesting relative to DSM expenditures and why?

A. The Company is requesting a finding of prudence for energy efficiency expenditures for the time period January 1, 1999 through August 31, 2001. The Commission authorization establishing the Company's DSM Tariff Rider, Schedule 91 (in Docket Nos. UE-941377 and UG-941378, reiterated in Docket No. UE-961309), requires that the Company demonstrate the prudence of its energy efficiency programs and expenditures at the time of a general rate case. In the Company's last general rate case (Docket Nos. UE-991606 and UG-991607), the Commission found prudent Avista's DSM expenditures for the period between January 1, 1995 and December 31, 1998.

Q. Would you briefly describe the tariff rider?

A. As the Commission is aware, the Company's DSM tariff rider, Schedule 91, was initially a pilot program started in 1995 to test a new funding mechanism to continue energy efficiency services at a time when many utilities were abandoning such efforts. The

DSM portion of the rider is currently a 1.95% surcharge to all rate classes with the exception of pre-existing special contracts. The Company's energy efficiency programs are offered through Schedule 90.

The tariff rider and the corresponding energy efficiency programs continue to be successful as measured by energy saved, cost-effectiveness tests, and acceptance by customers and stakeholders. Many states, including Oregon, California and Montana have adopted by legislation an energy efficiency funding mechanism similar to Avista's.

Q. What are the results of the energy efficiency expenditures?

A. Ten customer segment offerings available to all retail electric customers have saved over 197 million kWh for the 32 month time period at hand. Additional savings have been acquired through the Company's participation with the Northwest Energy Efficiency Alliance (NEEA). The total resource cost ratio of the Company's DSM activities is 1.21; the utility cost test yields a 2.71 benefit/cost. This indicates that the total resource benefits exceed costs by 21% and the utility benefits exceed investments by 171%. Based on these results, the Company's DSM expenditures of $18,010,611 have been reasonable and prudent. Page 1 of Exhibit No. ___(BWF-1) documents the results of these cost-effective tests and page 2 provides the related DSM expenditures and revenues on a cash basis. Pages 3 through 7 of this exhibit describes the cost-effectiveness methodology used to determine the prudence of the programs.

From a qualitative perspective, the tariff rider and associated energy efficiency programs have been successful. Customers participating in the DSM programs have benefited through lower bills. Non-participating customers have benefited from the Company acquiring low cost resources as well as maintaining the energy efficiency message through a consistent promotion of conservation awareness and infrastructure for the benefit of our service territory.

The Company convenes a technical advisory group, the External Energy Efficiency Board or "Triple E", twice a year to review program delivery and results, explain current issues, discuss future programs, and receive input. The Company appreciates the involvement of the Staff, Public Counsel, the Northwest Energy Coalition, Washington Department of Community Trade and Economic Development, Spokane Neighborhood Action Programs, E-Source, the Natural Resources Defense Council, as well as participating customer representatives.

Measurement and Evaluation ("M&E") Reports are prepared on a trimesterly basis and provided to the Triple E. These reports, which are the basis of Exhibit __ (BWF-1), provide all relative metrics for costs, savings, verification, and benefit (or cost-effectiveness) protocols.

Q. Exhibit __ (BWF-1) includes reference to natural gas DSM expenditures. Are you requesting a finding of prudence for expenditures relating to the natural gas DSM tariff rider, Schedule 191, at this time?

A. No. For the purposes of this docket, the figures provided relative to natural gas energy efficiency are for illustrative purposes only. The Company's M&E analysis separates gas and electric DSM for reporting purposes but analyzes each concurrently. The prudence of natural gas DSM expenditures will be addressed in the Company's next natural gas case.

Q. Did the Company increase its energy efficiency efforts this past summer?

A. Yes. The Company significantly ramped up its energy efficiency efforts this past summer in response to extraordinarily high wholesale market costs. In Spring 2001 the Company launched short-term programs with a goal of achieving immediate and significant savings in customers' homes and businesses by June 30, 2001. The effort was organized around six project teams to immediately deliver energy saving measures. This aggressive effort resulted in the distribution of 226,000 residential compact fluorescent lightbulbs (CFLs) and 123,800 commercial/industrial CFLs; 338,780 CFL coupons redeemed; 8,350 rooftop HVAC units serviced; 3,000 exit signs retrofitted; 250 commercial and industrial site-specific projects—previously "in-progress"—completed; and 1106 natural gas water heaters installed. During this time period the Company also aggressively communicated to customers the reasons why the region was facing higher power costs and energy efficiency suggestions. This was accomplished through the media and specific one-on-one efforts with organizations such as the Building Owners Management Association of Spokane.

Q. Are the costs of these programs included in the Company's request for prudence?

A. Yes. These costs are included in the Company's request for a prudence determination. However, these costs are <u>not</u> included in the Company's revenue requirement as part of this case. These costs of over $8 million will be recovered through the Company's existing DSM tariff rider over the next two to three years.

III. MISCELLANEOUS FEES

Q. Is the Company requesting any updated or new miscellaneous fees?

A. Yes. The Company is requesting that the Company's Schedule 70 reconnection charges and insufficient check ("NSF") charges be updated. The Company also is proposing a new late payment fee. Company witness Brian Hirschkorn has reduced the Company's revenue requirement by this amount accordingly.

Q. What is the basis for the increase in the reconnection and NSF charges?

A. The reconnection charges were last updated in 1988; the current NSF charge dates to 1981. The Company simply seeks to update these rates to reflect increases in related costs over time. The Company is proposing that the reconnection fee for regular hours be increased from $16.00 to $25.00, the after hours reconnection fee from $32.00 to $50.00, and the field collection fee from $8.00 to $15.00. The Company is proposing that the existing NSF fee of $7.50 be increased to $15.00. These fees are cost based and are the same as charges authorized for Northwest Natural Gas. Anecdotally, the current practice of merchants is to charge NSF fees in the range of $20 to $25.

The revision to the reconnection charges result in an estimated revenue increase of approximately $111,400. The NSF increase is expected to increase revenue by $18,200. Exhibit __ (BWF-2) provides the cost basis for and detailed revenue impact of these changes.

Q. What is the Company's proposal regarding a late payment fee?

A. The Company proposes the establishment of a new late payment fee of 1% to be applied on outstanding balances at the time the next monthly bill is issued. The purpose of this fee is two-fold. First, this charge is intended to place a customer's power bill at the same priority level as other bills. Late payment fees are standard across most product and service providers. Second, this charge is intended to have those customers who cause the Company to incur financing costs to carry the cost responsibility associated therein.

The electric revenue impact of the late payment fee is approximately $280,000.

Q. Do other energy companies have a similar late payment charge?

A. Yes. In Washington, Puget Sound Energy and Northwest Natural Gas have a similar 1% late payment charge for outstanding balances. Avista Utilities and the Idaho Power Company have a 1% late payment fee in Idaho.

Q. Are you concerned that this charge will have an effect on customers less able to pay their bills?

A. Avista will continue to promote the Company's Comfort Level Billing which equalizes bills over the year. The Company also works with customers on bill paying arrangements upon request. Avista's Low Income Rate Assistance Program should be helpful for those customers least able to pay their bills. While the Company does not collect data on bill paying relative to income levels, it is not clear that these proposals exclusively impact lower income customers. The Company believes that all demographic levels experience some bill-paying procrastination.

Q. Does the Company intend to propose a late payment fee and increases in the NSF charge and reconnection fees for Avista Utilities' natural gas service?

A. Yes. Avista Utilities will propose, at a later date by separate filing, similar fees for the Company's natural gas service. Similar charges would need to be adopted for natural gas service in that the Company issues joint bills for customers who have electric and natural gas service. The Company's billing system does not separate gas and electric receivable accounts from a customer perspective. Therefore, these fees would need to be identical for natural gas service. The revenue requirement impact on natural gas revenues associated with the planned natural gas miscellaneous fee filing would be examined by the Commission at the time of the Company's request, later in 2002 to coincide with the

Commission's order issuance in this docket.

IV. SUMMARY

Q. Would you please summarize your testimony.

A. Yes. Pursuant to guidelines established at the time of the Commission's authorization of Schedule 91, the Company seeks a finding of prudence for energy efficiency expenditures from January 1, 1999 through August 31, 2001. During this period, Avista's energy efficiency programs have saved over 197 million kilowatt hours at expenditures below the avoided cost of electricity and should be found prudent.

The Company requests that the reconnection charges and insufficient check fees be updated from their 1988 and 1981 levels, respectively, to reflect current costs. Avista also requests that a 1% late payment fee be authorized for outstanding balances. The miscellaneous fees described in my testimony are cost-based and are included in other Washington energy companies rate schedules. The Company's proposed revenue requirement has been reduced by the related miscellaneous fee revenue impact.

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

A. Yes, it does.

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. ____ (BWF-1)

WITNESS: BRUCE FOLSOM, AVISTA CORP.

Avista Utilities
Summary of Demand-Side Management Cost-Effectiveness
January 1, 1999 to August 31, 2001

TOTAL RESOURCE COST TEST		January 1, 1999 to August 31, 2001 Regular income portfolio		Limited income portfolio		Overall portfolio
Electric program electric avoided cost	$	36,134,910	$	4,380,179	$	40,515,089
Electric program gas avoided cost	$	28,766,016	$	(3,036,556)	$	25,729,460
Electric program non-energy benefits	$	5,368,604	$	-	$	5,368,604
TOTAL TRC BENEFITS	$	70,269,530	$	1,343,623	$	71,613,153
Electric program non-incentive utility cost	$	7,164,070	$	731,390	$	7,895,460
Electric program customer cost	$	47,778,853	$	3,336,342	$	51,115,195
TOTAL TRC COSTS	$	54,942,923	$	4,067,732	$	59,010,655
NET TRC BENEFITS	$	15,326,607	$	(2,724,109)	$	12,602,498
TRC B/C RATIO		1.28		0.33		1.21

UTILITY COST TEST		Regular income portfolio		Limited income portfolio		Overall portfolio
Electric program electric avoided cost	$	36,134,910	$	4,380,179	$	40,515,089
Electric program gas avoided cost	$	28,766,016	$	(3,036,556)	$	25,729,460
TOTAL UCT BENEFITS	$	64,900,926	$	1,343,623	$	66,244,549
Electric program non-incentive utility cost	$	7,164,070	$	731,390	$	7,895,460
Electric program incentive utility cost	$	13,216,266	$	3,336,342	$	16,552,608
TOTAL UCT COSTS	$	20,380,336	$	4,067,732	$	24,448,068
NET UCT BENEFITS	$	44,520,590	$	(2,724,109)	$	41,796,481
UCT B/C RATIO		3.18		0.33		2.71

PARTICIPANT TEST		Regular income portfolio		Limited income portfolio		Overall portfolio
Electric program lost revenue PV	$	99,698,370	$	16,891,683	$	116,590,053
Non-energy benefits	$	5,368,604	$	-	$	5,368,604
TOTAL PARTICIPANT BENEFITS	$	105,066,974	$	16,891,683	$	121,958,657
Customer project cost	$	47,778,853	$	3,336,342	$	51,115,195
Electric program incentive utility cost	$	(13,216,266)	$	(3,336,342)	$	(16,552,608)
TOTAL PARTICIPANT COSTS	$	34,562,587	$	-	$	34,562,587
NET PARTICIPANT BENEFITS	$	70,504,387	$	16,891,683	$	87,396,070
PARTICIPANT B/C RATIO		3.04		#DIV/0!		3.53

NON-PARTICIPANT TEST		Regular income portfolio		Limited income portfolio		Overall portfolio
Electric program electric avoided cost	$	35,754,946	$	3,753,289	$	39,508,235
	$	35,754,946	$	3,753,289	$	39,508,235
Electric program lost revenue PV	$	65,524,393	$	19,359,441	$	84,883,834
Electric program non-incentive utility cost	$	7,164,070	$	731,390	$	7,895,460
Electric program incentive utility cost	$	13,216,266	$	3,336,342	$	16,552,608
	$	85,904,729	$	23,427,173	$	109,331,902
NET NON-PARTICIPANT BENEFITS	$	(50,149,783)	$	(19,673,884)	$	(69,823,667)
NON-PARTICIPANT B/C RATIO		0.42		0.16		0.36

	Regular income portfolio	Limited income portfolio	Overall portfolio
Annual kWh's acquired	181,047,907	16,693,365	197,741,272
Annual therms acquired	4,807,467	(915,439)	3,892,028

CALCULATION OF ELECTRIC ENERGY EFFICIENCY RIDER BALANCE WITH INTEREST

	Per General Ledger Post Reconciliation										
	Total Washington/Idaho Jurisdictional Calculation					Washington Jurisdictional Calculation (9242.71)					
	Total WA/ID Beg. Balance	Total WA/ID Expenditures	Total WA/ID Revenues	Total WA/ID Interest	Total WA/ID End. Balance	Beg. Balance	Expenditures	Revenue	End. Balance w/o Interest	Interest	End. Balance w/ Interest
Jan-99	$ (2,652,739)	$ 228,179	$ (533,564)	$ (633,420)	$ (3,591,545)	$ (1,928,696)	$ 195,691	$ (371,659)	$ (2,104,664)	$ (479,679)	$ (2,584,343)
Feb-99	$ (3,591,545)	$ 285,881	$ (478,664)	$ (26,018)	$ (3,810,346)	$ (2,584,343)	$ 183,073	$ (321,493)	$ (2,722,763)	$ (18,804)	$ (2,741,568)
Mar-99	$ (3,810,346)	$ 519,351	$ (436,334)	$ (30,841)	$ (3,758,171)	$ (2,741,568)	$ 459,718	$ (292,771)	$ (2,574,621)	$ (22,191)	$ (2,596,812)
Apr-99	$ (3,758,171)	$ 1,006,074	$ (399,355)	$ (31,535)	$ (3,182,988)	$ (2,596,812)	$ 733,960	$ (266,606)	$ (2,129,459)	$ (22,243)	$ (2,151,702)
May-99	$ (3,182,988)	$ 448,743	$ (369,139)	$ (28,921)	$ (3,132,306)	$ (2,151,702)	$ 313,896	$ (247,453)	$ (2,085,259)	$ (19,785)	$ (2,105,044)
Jun-99	$ (3,132,306)	$ 519,704	$ (388,967)	$ (26,314)	$ (3,027,883)	$ (2,105,044)	$ 388,839	$ (266,981)	$ (1,983,186)	$ (17,736)	$ (2,000,923)
Jul-99	$ (3,027,883)	$ 403,800	$ (358,133)	$ (25,667)	$ (3,007,884)	$ (2,000,923)	$ 332,608	$ (237,115)	$ (1,905,429)	$ (17,108)	$ (1,922,537)
Aug-99	$ (3,007,884)	$ 604,292	$ (355,018)	$ (24,181)	$ (2,782,790)	$ (1,922,537)	$ 439,740	$ (272,035)	$ (1,754,832)	$ (16,348)	$ (1,771,180)
Sep-99	$ (2,782,790)	$ 275,836	$ (388,048)	$ (23,167)	$ (2,918,169)	$ (1,771,180)	$ 173,619	$ (302,045)	$ (1,899,605)	$ (15,390)	$ (1,914,996)
Oct-99	$ (2,918,169)	$ 522,986	$ (341,652)	$ (22,831)	$ (2,759,665)	$ (1,914,996)	$ 341,434	$ (260,080)	$ (1,833,642)	$ (15,359)	$ (1,849,001)
Nov-99	$ (2,759,665)	$ 203,447	$ (349,307)	$ (22,780)	$ (2,928,306)	$ (1,849,001)	$ 178,467	$ (263,916)	$ (1,934,450)	$ (15,683)	$ (1,950,134)
Dec-99	$ (2,928,306)	$ 1,074,990	$ (419,368)	$ (22,834)	$ (2,295,518)	$ (1,950,134)	$ 763,476	$ (317,111)	$ (1,503,768)	$ (15,830)	$ (1,519,598)
Jan-00	$ (2,295,518)	$ 437,364	$ (444,122)	$ (20,962)	$ (2,323,238)	$ (1,519,598)	$ 258,593	$ (350,395)	$ (1,611,400)	$ (14,457)	$ (1,625,857)
Feb-00	$ (2,323,238)	$ 323,251	$ (442,780)	$ (18,570)	$ (2,461,338)	$ (1,625,857)	$ 225,926	$ (318,411)	$ (1,718,343)	$ (13,106)	$ (1,731,449)
Mar-00	$ (2,461,338)	$ 669,207	$ (392,229)	$ (19,282)	$ (2,203,642)	$ (1,731,449)	$ 571,625	$ (296,857)	$ (1,456,680)	$ (13,989)	$ (1,470,669)
Apr-00	$ (2,203,642)	$ 631,372	$ (365,775)	$ (18,767)	$ (1,956,811)	$ (1,470,669)	$ 461,678	$ (277,469)	$ (1,286,460)	$ (13,342)	$ (1,299,802)
May-00	$ (1,956,811)	$ 601,448	$ (343,452)	$ (16,698)	$ (1,715,513)	$ (1,299,802)	$ 415,728	$ (263,312)	$ (1,147,386)	$ (11,544)	$ (1,158,930)
Jun-00	$ (1,715,513)	$ 695,758	$ (330,424)	$ (14,745)	$ (1,364,924)	$ (1,158,930)	$ 439,005	$ (251,458)	$ (971,382)	$ (10,245)	$ (981,627)
Jul-00	$ (1,364,924)	$ 697,455	$ (331,812)	$ (12,404)	$ (1,011,686)	$ (981,627)	$ 470,189	$ (252,072)	$ (763,511)	$ (8,919)	$ (772,430)
Aug-00	$ (1,011,686)	$ 469,152	$ (376,974)	$ (9,617)	$ (929,125)	$ (772,430)	$ 343,846	$ (290,327)	$ (718,911)	$ (7,309)	$ (726,219)
Sep-00	$ (929,125)	$ 930,455	$ (355,098)	$ (7,884)	$ (361,652)	$ (726,219)	$ 710,029	$ (269,892)	$ (286,082)	$ (6,244)	$ (292,327)
Oct-00	$ (361,652)	$ 442,850	$ (330,105)	$ (5,253)	$ (254,160)	$ (292,327)	$ 343,904	$ (251,174)	$ (199,596)	$ (4,244)	$ (203,840)
Nov-00	$ (255,925)	$ 926,192	$ (364,545)	$ (2,511)	$ 303,212	$ (101,812)	$ 746,315	$ (275,241)	$ 369,263	$ (2,067)	$ 367,195
Dec-00	$ 303,212	$ 563,889	$ (457,119)	$ (809)	$ 409,172	$ 367,195	$ 395,183	$ (346,109)	$ 416,270	$ -	$ 416,270
Jan-01	$ 409,172	$ 382,550	$ (517,846)	$ (264)	$ 273,612	$ 416,270	$ 273,560	$ (401,003)	$ 288,827	$ -	$ 288,827
Feb-01	$ 273,612	$ 834,144	$ (427,762)	$ (83)	$ 679,911	$ 288,827	$ 571,999	$ (326,964)	$ 533,861	$ -	$ 533,861
Mar-01	$ 679,911	$ 474,262	$ (398,632)	$ -	$ 755,541	$ 533,861	$ 353,187	$ (304,496)	$ 582,552	$ -	$ 582,552
Apr-01	$ 755,541	$ 656,889	$ (365,645)	$ -	$ 1,046,785	$ 582,552	$ 475,160	$ (279,452)	$ 778,259	$ -	$ 778,259
May-01	$ 1,046,785	$ 1,400,009	$ (422,186)	$ -	$ 2,024,607	$ 778,259	$ 1,012,243	$ (343,555)	$ 1,446,948	$ -	$ 1,446,948
Jun-01	$ 2,024,607	$ 2,166,661	$ (425,359)	$ -	$ 3,765,909	$ 1,446,948	$ 1,584,444	$ (310,127)	$ 2,721,265	$ -	$ 2,721,265
Jul-01	$ 3,765,909	$ 2,084,271	$ (484,309)	$ -	$ 5,365,871	$ 2,721,265	$ 1,540,624	$ (319,153)	$ 3,942,736	$ -	$ 3,942,736
Aug-01	$ 5,365,871	$ 3,471,771	$ (504,122)	$ -	$ 8,333,520	$ 3,942,736	$ 2,312,848	$ (331,998)	$ 5,923,586	$ -	$ 5,923,586
1999		$ 6,093,281	$ (4,817,550)	$ (918,510)			$ 4,504,522	$ (3,419,265)	$ (24,431,679)	$ (676,159)	
2000		$ 7,388,392	$ (4,534,436)	$ (147,502)			$ 5,382,022	$ (3,442,717)	$ (9,374,219)	$ (105,466)	
8 mo. 2001		$ 11,470,557	$ (3,545,862)	$ (346)			$ 8,124,066	$ (2,616,749)	$ 16,218,035	$ -	
32 mo. Total		$ 24,952,230	$ (12,897,848)	$ (1,066,359)			$ 18,010,611	$ (9,478,732)	$ (17,587,863)	$ (781,624)	

Details of DSM Cost-Effectiveness Analysis

Contents of this Section

Overview of Cost-Effectiveness

This attachment provides an overview of the methodology used to obtain the cost-effectiveness calculations provided in this filing. Particular attention has been given to customized approaches necessitated by data issues or specific program issues.

Avista's programs have been evaluated as individual programs and aggregated into regular income and limited income portfolios. Additional alternative treatments of overhead costs are also provided.

Details concerning the treatment of critical factors in the cost-effectiveness calculations are noted in this context. These include the components of utility costs, the treatment of customer measure cost, in-progress projects, customer and societal non-energy benefits and project energy savings.

Cost-effectiveness statistics and energy savings are summarized in a tabular format. Detailed descriptive statistics are available in supporting work papers. A brief description of the four standard practice tests and their interpretation is also provided

All programs that are offered in Washington during the relevant time period have been evaluated in this package.

Calculation of Utility Costs

Avista's accounting systems divides utility Energy Efficiency costs into four categories; (1) non-incentive implementation costs, (2) monitoring, measurement and evaluation (M, M & E) costs, (3) direct incentive costs and (4) overhead costs. The first three of these costs are explicitly assigned to each program. When a charge is made to that program it is given a sub-account designating it as an implementation, M, M & E or incentive expense. Overhead costs are those expenditures that are not directly assignable to any specific program.

In consideration of different uses of this information, we have calculated the individual programs and the regular income and limited income portfolio both with and without overhead costs. This approach allows for the separation of the cost-effectiveness of the technology and program delivery mechanism from the programs' ability to contribute to offsetting the costs incurred for non-program specific general costs.

General, or 'overhead' costs, have been allocated among programs based upon each programs' energy savings. These allocations may change as Avista transitions from a traditional programmatic organization of energy services to a technology and customer segment approach

<u>Treatment of Non-Utility Costs</u>

The tracking of non-utility costs has required more care, effort and interpretation on the part of the analytical staff. These costs are by definition under the control of an external party but are typically 70% of the total resource cost. Special effort is frequently required to separate the project costs associated with energy efficiency from non-energy related portions of the project. The degree of effort required to obtain quality data on this topic is warranted considering the substantial impact that these costs have upon the total resource and participant cost-effectiveness.

The customer costs that have been quantified for this analysis are almost exclusively associated with the capital cost of the purchase and installation of the end-use equipment. Other customer costs may include design costs, engineering fees, lost productivity during the installation and assorted miscellaneous costs. Avista captures these incremental non-capital customer costs as a non-energy "disbenefit."

The objective of the measurement of non-utility costs is to ascertain the costs associated with the energy savings acquired by the efficiency measure. It is of critical importance that the energy savings and the associated costs be based upon consistent assumptions. Ideally these costs would exclude non-quantifiable benefits that are not included in the project benefits (i.e. aesthetics, productivity, comfort etc.). The measure life of the installed end-use system would be equal to that of the base case end-use system, making adjustments for differences in measure life unnecessary. There would be no degradation of energy savings over time. Incremental maintenance savings or costs would be easily identified and quantifiable. The collection of these measure lives would be easily incorporated into the implementation process and accurately relayed to the analyst.

In practice these ideals are difficult to achieve. It is the task of the analyst to craft a means of adapting the realities of program implementation and customer needs to the analytical requirements. The following is a brief description of how these problems have been overcome for purposes of developing meaningful estimates of program cost-effectiveness.

Since the customer measure cost is a component in Avista's incentive calculation model it is individually tracked and documented. In practice it is necessary to overcome difficulties surrounding bid and invoice detail and the need to separate the energy-efficiency portion of the bid from the remainder.

The issues that are specific to technologies and applications will be individually outlined below.

For lighting end-uses the customer measure cost is based upon the total measure cost of the high-efficiency alternative adopted and an engineering estimate of the standard efficiency alternative for that specific adaptation. The engineering estimate is based upon standard vendor pricing data applied as it applies to a specific project. Vendor information regarding the costs of a basecase efficiency system is unreliable for several reasons, not the least of which is that vendors know that these bids are 'hypothetical' bids when the customer is working with Avista.

Avista has employed a means of separating the energy-efficiency portion of projects (lighting and otherwise) from the non-efficiency capital investment. This methodology is employed exclusively in retrofit circumstances.

On rare occasions it is possible for the high-efficiency scenario is occasionally less costly than the standard efficiency base case. This is indicative of the substantial design efficiency benefits that accrue to some projects as a result of Avista's intervention (i.e. improperly ballasting fixtures etc.).

A similar analysis was performed for electric to natural gas fuel-switching. An engineering estimate was made of the cost of installing electric equipment of similar performance to the natural gas space and/or water heat equipment that was actually installed, including the cost of gas piping.

In the case of both the lighting and fuel-conversion program it was stated (and confirmed in a review of sample jobs) that the existing end-use equipment was beyond the economic life at the time of replacement.

Customer Non-Energy Benefits

It is frequently the case that the motivating factor behind the customer seeking to retrofit a pre-existing end-use with a higher efficiency alternative, or to opt for a higher than standard efficiency in new construction, is based as much or more upon the non-energy benefits as the energy benefits.

All forms of non-energy benefits are typically difficult to quantify in any reasonably accurate manner. Consequently most cost-effectiveness analyses exclude these substantial benefits. By doing so the analysis may wrongfully conclude that a program is cost-ineffective and, by ignoring these benefits in the analysis, there is little or no attempt to design or implement programs in such a way as to maximize these benefits.

Avista's initial attention in this area was focused on the most significant and most easily quantified components. These include such benefits as the maintenance savings from LED traffic light conversion, the non-energy resource savings associated with the Resource Management Partnership Program (RMPP) and so on. These details are incorporated in the Company's workpapers.

Avista identifies non-energy benefits even when these benefits cannot be quantified with any degree of confidence. This identification of benefits (or, in some instances, disbenefits) will provide us with meaningful, though anecdotal, information concerning the value that the customer places on the investment.

Energy Savings Calculations

The energy savings used in the attached cost-effectiveness evaluation are based upon completed MM&E results when available. When full MM&E data is not available energy savings are based upon project-specific engineering calculations claimed by the Customer Service and Solutions Department with adjustments made based upon the Energy Delivery Business Analysis Department.

The energy savings include contractual and/or engineering estimates of projects that have reached the internally-defined 'contract' or 'construction' phase of progress. Those projects in the 'contract' phase have 75% of their contracted energy savings included in the total program savings while those in the 'construction' phase have 95% of their savings included. These partial credits are based upon an estimate of the projects that will drop out of the program at each phase. (Reviews made since these dropout rates have been estimated indicate that the original assumptions were unduly conservative. Recalculations of these dropout rates are in progress.)

The customer costs and utility incentives have been extrapolated as appropriate for the inclusion of in-progress energy savings.

For purposes of completing an estimate of the Participant and Non-Participant cost-effectiveness it was necessary to determine billed demand savings for several programs. These claims were based upon an assumption of a 61% customer-coincident load factor for the effected end-uses.

Natural gas usage of fuel-switching programs has been based upon an 80% relative efficiency differential between electric and natural gas systems and applied to the audited claims of electricity savings. Both natural gas savings and incremental use have been fully incorporated in the cost-effectiveness analysis, making the benefit to cost ratios a true all-fuel estimate.

Avoided Costs and Rates

The most recent Washington electric and natural gas avoided costs and Washington customer rates were applied to the calculation of the cost-effectiveness.

Electric line losses and gas distribution losses have not been incorporated into the avoided costs. No additional generation, transmission and distribution capacity values have been included in this analysis beyond what is inherent in the approved Washington avoided costs. Considering that most of the end-uses which are addressed by our programs are generally the same load profiles as the system as a whole, the omission of the capacity costs are of relatively little importance and results in a conservative evaluation of cost-effectiveness.

Descriptive Statistics

Several descriptive statistics are provided in addition to the cost-effectiveness calculations. These statistics are useful in diagnosing successes or failures in particular programs and are actively used for purposes of managing the program over the entire program life cycle.

These statistics include; (1) utility non-incentive cost per first year kWh, (2) utility incentive cost per first year kWh, (3) customer cost per first year kWh and (4) societal cost per first year kWh. In interpreting these results, and particularly when comparing one program to another, it is necessary to realize that these statistics are based upon the first year kWh only and do not consider differences in measure lives between programs. Furthermore, incidental therm savings are not valued in this calculation although they do contribute to the all-fuel cost-effectiveness results of the program.

Calculation and Interpretation of the Four Standard Practice Tests

Energy efficiency programs are typically evaluated upon the basis of four different cost-effectiveness tests. These tests and a brief description are:

Total Resource Cost (TRC) test: This is a societal benefit-cost analysis and indicates what the cost-effectiveness of a project is to the whole of society. In recent years the inclusion of non-energy benefits in this test has become more acceptable. This could include reduced maintenance, reduced insurance and potentially even the quantified value of reduced emissions and other societal costs of energy generation, transmission and delivery.

Utility Cost Test (UCT): This test indicates whether the utility cost of serving the customer goes up or down as a result of the program. This is not the customer 'energy' cost, which would include end-use equipment and similar costs, it is only the costs incurred by the utility to serve the customer.

Participant test: This is the cost-effectiveness for the participating customer. It includes the value of the energy savings (and other savings) from the project vs. the customer project costs.

Non-Participant test (also known as the Rate Impact, or RIM, test): This indicates if the program will result in a rate increase or decrease.

The results of these tests are presented in a tabular format as part of this filing.

The cost-effectiveness tests calculations for all programs include increased or decreased usage of non-electric fuels as a result of the project. At this time natural gas is the only non-electric fuel impacted by Avista programs. Significant incidental gas savings are obtained as a result of Avista's recommendations. These savings are largely offset with increased gas usage as a result of fuel-switching programs.

BEFORE THE WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

DOCKET NO. UE-01_______

EXHIBIT NO. ____ (BWF-2)

WITNESS: BRUCE FOLSOM, AVISTA CORP.

Proposed Fees for Washington General Rate Case

	Current Charge	# of Occurances in Year 2000	Amount Charged	Proposed Charge	Estimated Charges at proposed rate	Estimated increase in Annual Revenue
NSF Charge	$ 7.50	2,427	$ 18,202.50	$ 15.00	$ 36,405.00	$ 18,202.50
Field Collection Fee	$ 8.00	1,418	$ 11,344.00	$ 15.00	$ 21,270.00	$ 9,926.00
Reconnect Fee - Reg. Hours	$ 16.00	5,926	$ 94,816.00	$ 25.00	$ 148,150.00	$ 53,334.00
Reconnect Fee - After Hours	$ 32.00	2,674	$ 85,568.00	$ 50.00	$ 133,700.00	$ 48,132.00
Late Charge (new fee) Electric portion	-			1%	$ 399,113.00	$ 280,035.00
					Total	**$ 409,629.50**

Cost Analysis - NSF Check Charge

Year 2000

2427 return check charges in WA @ $7.50 = $18,202.50
Total NSF for 2000 in all states = 4536 (1561 checks were from paystations payments, 2975 went thru B of A)
Proposed NSF Charge in WA = $15.00

$ 18,330.00	CSR - average loaded labor @ $23.50/hour
$ 2,975.00	Bank of America charges $2.00 per return item
	Other Fees include EFT (electronic fees transfer) @ $.60 each time we send an item through & $.35 each time an item is returned by EFT
$ 2,979.68	Total EFT charges Oct 2000 - Sept 2001 = $5959.35 (1/2 for Washington only)
$ 6,770.91	Paystation Charges = (total for Year 2000 = $13,541.81, 1/2 for Washington only)
$ 4,780.64	Collection Notices and Action Cards related to NSF's in Washington in Year 2000
$ 35,836.23	

$35,836.23 / 2427 check = $14.77 per check

CSR spends approx. 15 hours per week on Washington NSF's

$ 23.50	Cost per hour
780	hours per year
$ 18,330.00	

Year 2000, notices and action cards for NSF's in Washington

FLD_REQUE	Fld_Reason_Desc	Cost	Total
373	24 HOUR NOTICE : RETURNED CHECK	$ 0.38	$ 141.74
405	7DAY DISC: RETURNED CHECK	$ 0.38	$ 153.90
299	COLLECT OR DISCONNECT : RETURNED CHECK	$ 15.00	$ 4,485.00
			$ 4,780.64

Cost Analysis - Field Visit

Year 2000

1418 Field Visit charges in WA @ $8.00 = $11,344
Proposed Field Visit charge in WA = $15.00

Analysis based on 9 full time OSM's in Yr2000			
Average Cost per Collection Visit	Collection Orders Worked	Mileage Expense	Salary
$ 12.51	54,539	$104,681.00	$577,847.68

Cost Analysis - Reconnect Charge

Year 2000

5926 Reconnect Charges (regular hours) in WA @ $16.00 = $94,816.00
2674 Reconnect Charges (after hours) in WA @ $32.00 = $85,568.00
Proposed Reconnect Charge (regular hours) in WA = $25.00
Proposed Reconnect Charge (after hours) in WA = $50.00

OSM - Average Loaded Labor = $33.36 / hour
Overtime Labor = $33.36 X 1.5 = $50.04
Union Contract requires a minimum of 1 1/2 hours of O.T. for every after hours call out

Analysis based on 9 full time OSM's in Yr2000			
Average Cost per Collection Visit	Collection Orders Worked	Mileage Expense	Salary
$ 12.51	54,539	$104,681.00	$577,847.68

Reconnect Visit requires to 2 trips (1 trip to disconnect & 1 trip to reconnect)

$	12.51
	2
$	**25.03**

Cost per Reconnect during regular business hours

1% Late Charge - Electric vs. Gas
70% of Year 2000 revenue was Electric (residential/commercial)
30% of Year 2000 revenue was Gas (residential/commercial)

$	399,133	estimated total late charge
$	280,035	estimated late charge for Electric portion of bill
$	119,098	estimated late charge for Gas portion of bill

WA Revenues - Year 2000						
	Electric		Gas			
Residential	$	102,800,750	$	56,006,134		
Commerical	$	100,162,877	$	30,313,349		
total	$	202,963,627	$	86,319,483	$	289,283,110
		0.70		0.30		