BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC v. Avista Corporation, d/b/a Avista Utilities

DOCKET NOS. UE-070804, UG-070805

DIRECT TESTIMONY OF J. RICHARD HORNBY (JRH-1T)

ON BEHALF OF

PUBLIC COUNSEL

OCTOBER 17, 2007

NON-CONFIDENTIAL

DIRECT TESTIMONY OF J. RICHARD HORNBY (JRH-1T)
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## I. INTRODUCTION / SUMMARY

**Q: Please state your name, employer, and present position.**

A: My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

**Q: On whose behalf are you testifying in this case?**

A: I am testifying on behalf of the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) as well as on behalf of The Energy Project.

**Q: Please describe Synapse Energy Economics.**

A: Synapse Energy Economics (Synapse) is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

**Q: Please summarize your work experience and educational background.**

A: I am a consultant specializing in planning, market structure, ratemaking, and gas supply/fuel procurement in the electric and gas industries. Over the past twenty years, I have presented expert testimony and provided litigation support on these issues in approximately 100 proceedings in over thirty jurisdictions in the United States and Canada. Over this period, my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and, prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the

Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my current resume to this testimony as Exhibit No. ___ (JRH-2),

**Q: What is the purpose of your testimony?**

A: Avista Utilities (Avista or the Company) is requesting increases in its rates as well as several changes in its revenue recovery mechanisms. Public Counsel and The Energy Project retained Synapse to review various aspects of Avista's requests.

Q: **What data sources did you rely upon to prepare your testimony?**

A: I relied primarily on the Direct Testimony, exhibits, and workpapers of the Avista witnesses as well as their responses to data requests. In addition, I reviewed Orders issued by the Washington Utilities and Transportation Commission (WUTC) in various other proceedings. I have also reviewed the partial settlement stipulation.

**Q: Please summarize your major conclusions**.

A: My major conclusions are as follows:

- Avista's funding of programs for limited income customers has not kept pace with the increases in its retail rates.
- Avista's proposed power cost only rate case (PCORC) mechanism is not reasonable.

- Avista's proposals to change its accounting treatment of demand side management (DSM) program costs and to recover fixed costs lost to DSM are not reasonable.
- The purpose of Avista's inclusion of information about its proposed Advanced Meter Reading (AMR) program without a request for cost-recovery is unclear. Avista's statements appear to solicit, at least implicitly, some form of pre-approval of its program without the Commission's full consideration. Avista must ultimately demonstrate that its proposed investments in AMR are prudent as well as used and useful. It has not done so here. Prior to any cost recovery, Avista will need to address the serious financial and policy concerns implicated by such a program.

**Q: Please summarize your recommendations**.

A: I recommend that the Commission include the following conditions in its order in this proceeding:

- Approve and adopt the partial settlement stipulation to adjust Schedules 91 and 191 in order to increase annual funding for LIRAP up to the following levels: electric, $2,496,000, and natural gas, $1,262,000. This represents a total of $3,758,000 per year and is intended to approximately match the overall percentage increase in retail rates approved in this case.
- Approve and adopt the partial settlement stipulation to increase funding for Avista's limited-income DSM programs to $1,132,000.

- Reject Avista's proposed PCORC mechanism.
- Approve the partial settlement stipulation which withdraws Avista's proposals to change its accounting treatment of DSM program costs and recover fixed costs lost to DSM.
- State that nothing in the order in any way constitutes a pre-approval of Avista's AMR program, and that Avista will bear the financial impact if a future proceeding determines that a portion of this investment is not prudent, or used and useful.

**Q: Did you also examine power supply issues in this case?**

A: Yes. I reviewed power supply issues raised in Avista's filing. Public Counsel is in agreement with the positions of Staff and the Industrial Customers of Northwest Utilities (ICNU) on these issues. Along with Staff and ICNU, Public Counsel supports the partial settlement stipulation, which sufficiently resolves our concerns related to power supply issues.

## II. FUNDING OF LIMITED INCOME PROGRAMS

**Q: What limited income programs does Avista fund from revenues it collects from ratepayers?**

A: Avista funds two types of assistance to limited income customers: Low Income Rate Assistance Program (LIRAP) and energy-efficiency measures for limited-income customers. Avista collects the revenues to fund these programs under its public purpose tariff riders, Schedules 91 (electricity) and 191 (natural gas).

### A. Low Income Rate Assistance Program (LIRAP)

**Q: When was the LIRAP established?**

A: LIRAP was established in 2001 in Docket Nos. UE-010436 and UG-010437. The WUTC authorized Avista to collect revenues to fund that budget by broadening the scope of its public purpose tariff riders. The program was created with a May through April fiscal year, and the initial surcharges under the riders were expected to collect approximately $3 million annually.[1] The program was designed to serve limited-income customers, i.e. those near or below the Federal Poverty Level (FPL). At that time, Avista estimated that 20 percent of households in its service territory were at or below the FPL.[2]

**Q: Please describe the funding of LIRAP since 2001.**

A: The annual budget for LIRAP remained at approximately $3 million for the first four program years, May 2001 through April 2005. The annual budget increased to approximately $3.3 million in 2005/2006 and to $3.9 million in the 2006/2007 fiscal year.[3] The increases in those two years were due to the temporary infusion of an additional $1.2 million as part of the settlement of Avista's 2005 general rate case ($0.3 million in the 2005 program year and $0.9 million in the 2006 program year). That infusion was not a permanent increase, however, and is now gone. Therefore, my understanding is that the budget for the 2007/2008 program year has declined to the $3 million level of prior years.

[1] Avista Response to Public Counsel Data Request No. 163, Attachment A, p. 1.
[2] *Id.*, p. 2.
[3] Annual LIRAP reports for program years 2001/2002 through 2006/2007, filed in Docket Nos. UE-010436 & UG-010437.

**Q: Has Avista proposed any change in the funding level for LIRAP in this proceeding?**

A: No.

**Q: Has funding for LIRAP through the tariff riders kept pace with the increases in Avista's total revenues through 2006?**

A: No. The annual funding of LIRAP through the tariff rider mechanism has consistently generated approximately $3 million annually since the program's inception in 2001. Avista's overall retail revenues, in contrast, have increased about 42 percent from 2001 to 2006. This experience is illustrated in Exhibit No. ___(JRH-3), based on data from Avista Response to Public Counsel Data Request No. 164 Supplemental, Attachment A, page 1, presented in Exhibit No. ____(JRH-4).

As noted above, in the 2005 and 2006 program years, LIRAP received a temporary infusion of $1.2 million as a result of the 2005 general rate case settlement. With the expiration of that funding the LIRAP budget will decline substantially relative to Avista's total revenues.

**Q: Did the 2005 rate case settlement provide for consideration of future funding levels for LIRAP once the two-year temporary increases expired?**

/ /

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/ / / /

A: Yes. Section 15 (a) of that settlement states:

> …[a]t the end of the two year period, several factors will be considered regarding future funding levels, such as an assessment of the general level of the tariff rider (including DSM), need for and use of LIRAP funds, continuation of and funding levels for the low-income tax credit, and acceptance by the Commission.[4]

**Q: Aside from the decline in the funding of LIRAP as a percentage of retail revenues, is there any other evidence to support an increase in the program's annual funding?**

A: Yes. According to the Staff memo supporting approval of LIRAP in 2001, 20 percent of households in Avista's service territory were below the Federal Poverty Level (FPL) at that time.[5] If that statistic is still approximately correct, then there are currently between 40,000 and 67,000 households in Avista's service territory below the FPL. (The summary of Avista's requested electric and gas rate increases in this proceeding indicate that it has 196,000 residential electric customers and 139,000 residential gas customers). In contrast, in 2006 with a budget of $3.8 million, LIRAP served approximately 6,200 customers who were at or below the FPL, as indicated in Table 4 of the LIRAP Sixth Annual Report**.**[6]

In addition, a review of population and poverty data in Spokane County, which represents a significant portion of Avista's Washington customers, reveals that population levels are increasing, including the proportion of individuals living below the

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[4] *WUTC v. Avista*, Docket Nos. UE-050482 & UG-050483, Order No. 05, Approving and Adopting Settlement Agreement With Conditions, Settlement Agreement, pp. 6-7. (hereafter, "2005 Final Order" or "2005 Settlement."

[5] Avista Response to Public Counsel Data Request No. 163 Attachment A.

[6] Sixth Annual LIRAP Report, Compliance Filing, Docket Nos. UT-010436 & UG-010437, Table 4, p. 7. LIRAP provides assistance to customers with incomes at or below 125 percent of the FPL, and served over 7,800 customers during the 2006-2007 Program Year. *Id.*

FPL. Tables 1 and 2 below provide U.S. Census Data for the City of Spokane and Spokane County, as well as trends in Avista's residential customer counts. From 2000 to 2006, the estimated number of individuals living below the FPL grew by 12 percent in Spokane, and by 16 percent in Spokane County. This trend, as well as the fact that Avista has experienced customer growth since LIRAP's inception in 2001, provides additional support for increasing the level of funding of LIRAP.

**Table 1. Population and Poverty Data: Spokane City and County**

| | **2000** | **2006** | **% Change** |
|---|---|---|---|
| **Spokane (City)** | | | |
| (A) % of Individuals Below FPL | 15.9% | 17.6% | |
| (B) Total Population | 195,629 | 197,446 | 1% |
| (C=A×B) Est. Individuals Below FPL | 31,105 | 34,750 | 12% |
| **Spokane County** | | | |
| (D) % of Individuals Below FPL | 12.3% | 13.3% | |
| (E) Total Population | 417,939 | 446,706 | 7% |
| (F=D×E) Est. Individuals Below FPL | 51,406 | 59,412 | 16% |

Source:
U.S. Census Bureau, 2000 Census, 2006 American Community Survey
http://factfinder.census.gov/home/saff/main.html?_lang=en

**Table 2. Avista Residential Customer Count**

| | 2001 | 2004 | 2007 | % Change |
|---|---|---|---|---|
| Residential Electric Customers | 181,000 | | 196,000 | 8% |
| Residential Gas Customers | | 129,000 | 139,000 | 8% |

Sources:
2001 Electric Residential: UE-011595, rate case summary, Oct. 30, 2001 customer count
2004 Gas Residential: UG-041515, rate case summary, May 31, 2004 customer count
2007 UE-070804 & UG-070805, rate case summary, March 31, 2007 customer count
Gas customer counts include residential and small commercial

**Q: Do you recommend that the WUTC approve an increase in LIRAP funding?**

A: Yes. I recommend that the WUTC approve the proposed increase in LIRAP funding included in the partial settlement stipulation, from current levels of about $3 million to $3,758,000, collected annually through the tariff riders. I believe an increase of this magnitude is reasonable, particularly in light of the increases in Avista's rates since LIRAP's inception in 2001, and the estimated increase in residential customers and individuals living below the FPL as discussed above.

Between 2000 and 2006, Avista electric customers have experienced four rate increases that have raised bills significantly. Avista natural gas customers have endured eight separate rate increases in the same time period.[7] While LIRAP benefited from a temporary infusion of $600,000 per year for a two-year period under the 2005 rate case settlement, that infusion has ended. The increase in LIRAP funding reflected in the partial settlement is intended to approximately match the overall percentage increase in retail rates ultimately approved in this case.

[7] Exhibit No.__(JRH-20).

**B. Limited-Income Energy Efficiency Programs**

**Q: Please describe the funding of the limited-income energy efficiency program since 2001.**

A: Avista's annual budget for this program has remained at approximately $0.93 million for calendar years 2002 through 2005 and then declined to $0.87 million in 2006.[8]

This program is funded primarily from an allocation of the DSM program funds collected under Schedules 91 and 191. In addition, in the years 2003 through 2005, Avista allocated $264,880 per year to this program from funds it received from the Bonneville Power Administration (BPA) under the Conservation and Renewable Discount (C&RD). In 2006, Avista did not allocate any of its C&RD funds to limited income efficiency programs. As part of the settlement of its 2005 general rate case, Avista agreed to allocate an additional $200,000 per year to the program over and above the $900,000 per year it presently provided for DSM funding. At that time, the parties expected the new budget would be approximately $1.1 million, the $0.9 million Avista had been funding with collections and BPA monies plus the new $0.2 million.[9]

**Q: Has Avista proposed any change in the funding level for its limited-income efficiency program in this proceeding?**

A: No.

[8] Avista's Supplemental Response to Public Counsel Data Request No 167.
[9] 2005 Settlement, Section 15(A), p. 6. Avista indicated that their 2006 annual budget for low-income DSM programs was $866,700. Avista's Supplemental Response to Public Counsel Data Request 167.

**Q: Do you recommend that the WUTC approve an increase in funding of energy efficiency programs for limited-income customers to offset the loss of BPA funding?**

A: Yes. I recommend that the WUTC approve the increase in funding of energy efficiency programs for limited-income customers proposed in the partial settlement stipulation. Under the partial settlement, Avista agrees to allocate $1,132,000 in 2008 for limited income DSM programs. This will help offset the loss of BPA funding resulting from the suspension of the Residential Exchange benefit.[10]

## III. POWER COST ONLY RATE CASE (PCORC) MECHANISM

**Q: Please summarize Avista's request for a PCORC.**

A: Avista is requesting establishment of a PCORC similar in design to the current PCORC of Puget Sound Energy (PSE). Mr. Kelly Norwood presents this request in his Direct Testimony. According to Mr. Norwood, a PCORC would enable Avista to request adjustments in its base rates to reflect major investments in generation and transmission (G&T) capacity without going through a full general rate case proceeding.[11]

**Q: Is this the first proceeding in which Avista has requested the establishment of a PCORC?**

A: No. Avista effectively requested the establishment of a PCORC in its power cost only filing of August 2006 in Docket No. UE-061411. The WUTC rejected that application in Order 04 in that proceeding.

[10] As part of its response to the suspension of the Residential Exchange, Puget Sound Energy (PSE) filed in May of 2007 to increase Schedule 120, its electricity conservation tariff rider, to reflect the loss of BPA conservation rate credits. PSE's tariff filing was approved by the WUTC. Order 01, Docket No. UE-071015, June 6, 2007.
[11] Exhibit No. ___ (KON-1TC), Norwood Direct, pp. 2-9.

**Q: Is establishment of a PCORC for Avista justified in this proceeding?**

A: No. The rationale that Avista has presented for establishing a PCORC does not justify a departure from traditional ratemaking principles.

**Q: Why would establishment of a PCORC represent a departure from traditional ratemaking principles?**

A: The WUTC addressed this issue in Order 04 in Docket No. UE-061411.[12] From a policy perspective, any mechanism that allows a utility to adjust its rates between general rate cases to reflect changes in a single, or limited, category of costs is generally considered an exception to the traditional principles of utility rate regulation. Under these traditional principles, the regulator approves a utility's base rates only after a comprehensive review of all categories of costs and revenues as well as an assessment of the number of customers being served and their usage. Under a rate adjustment mechanism such as Avista's proposed PCORC, the utility would be allowed to adjust its rates to reflect a change in a single cost, relative to the test year values used in its last rate case, without determining if there are offsetting changes in other costs. This can lead to a mismatch between costs and revenues.

The one common exception to these traditional ratemaking principles is a mechanism that adjusts rates to reflect changes in fuel prices between general rate cases. In Washington, the versions of this mechanism that are in place for electric utilities are

[12] *In the Matter of the Petition of Avista Corporation, d/b/a/ Avista Utilities, For an Order Approving Avista's Update of its Base Power Supply and Transmission Costs,* Docket No. UE-061411, Order 04, Granting Motion to Dismiss. (hereafter, "2006 Order to Dismiss PCORC Filing").

referred to as an energy recovery mechanism (ERM) or power cost adjustment (PCA), while the versions in place for gas utilities are referred to as purchased gas adjustment clauses (PGAs). The changes in purchased power and fuel or natural gas expenses covered by such rate mechanisms are generally considered to be material, volatile (meaning they are difficult to predict and they can vary significantly), and largely outside the control of the utility. Based upon the unique characteristics of those costs regulatory commissions have approved, as exceptions to traditional principles, rate adjustment mechanisms in an effort to produce an equitable balance between the interests of ratepayers and the interests of the utility.

**Q: Are you aware of any corresponding widespread trend towards the establishment of rate adjustment mechanisms for changes in generation and transmission capacity costs?**

A: No.

**Q: Are the cost changes that Avista proposes to reflect through its PCORC sufficiently similar to those it recovers through its ERM to warrant a PCORC?**

A: No. The changes in generation and transmission (G&T) capital costs that Avista proposes to recover through its PCORC may, in some future years, be material. However, those cost changes are neither largely beyond the control of Avista management nor are they volatile. Investments in G&T tend to be periodic and large. However, those attributes are not the same as being *volatile*. Expenses that are volatile are those that are subject to frequent, large and unpredictable fluctuations.

It is also important to note that Avista has the ability to include an Allowance for Funds Used During Construction (AFUDC) on its capital projects as a component of its revenue requirements when it files a general rate cases. Under an AFUDC, as the utility makes ongoing outlays for construction of major projects (typically those that take more than one year to construct), it enters those outlays into a holding account. In addition, it also books to a holding account the carrying charges on the balance of construction costs in holding accounts. Those booked carrying charges are the AFUDC. The balance in those accounts, both investment outlays and the AFUDC amount, are eligible for consideration as rate base additions in the next base rate case after the construction project enters commercial service. (Typically, once a project has entered commercial service, further AFUDC typically may not be accrued, and the utility must start depreciating the asset. This provision addresses the fact that the utility controls when it files rate cases and is intended to discourage artificial inflation of rate base.) Thus, even if the utility is not able to put a generation or transmission asset into rates until its next base rate case, it is not harmed financially.

The fact that Avista must choose whether to file a rate case once an asset is in service has traditionally been regarded as reasonably necessary in order to maintain a proper balance between protecting ratepayers and providing the utility with an opportunity to earn a reasonable return. Thus, Avista's ability to recover an AFUDC in its rates helps the Company recover its investments in generation and transmission in an appropriate manner.

**Q: Is Avista expecting to acquire a significant quantity of new generation capacity each year over the next several years?**

A: No. Avista has stated that it is not facing any substantial generation resource additions until 2011, when it contemplates acquiring about 280 MW of gas-fired combined cycle gas turbine (CCGT) capacity.[13] After that, it does not forecast another major capacity acquisition until 2014.[14] In addition, Avista has the opportunity to acquire 275 MW of CCGT capacity effective 2010 at an attractive price under a power purchase contract with the Lancaster Generating Plant. This opportunity is described in its recently released 2007 Integrated Resource Plan (IRP).[15]

**Q: In Order 04 in Docket No. UE-061411, the WUTC specified the type of evidence that Avista should present to support a request to establish a PCORC. Has Avista presented all of that evidence in this proceeding?**

A: No. Order 04 in Docket No. UE-061411 states in part:

> **…** [i]f Avista wishes to pursue its proposal, it must ask authority for the periodic rate adjustment mechanism in a general rate case; presenting evidence and argument clearly defining the proposal, identifying appropriate conditions on its operation, showing how it benefits both ratepayers and stockholders, addressing the costs and benefits of the process based on performance in a test year and analyzing the effect of an ERM/PTC process on the allowed rate of return.[16]

In this proceeding Avista has not provided evidence:

- showing how the proposed PCORC benefits both ratepayers and stockholders;

[13] Exhibit No. ____, (JRH-6), Avista Response to Staff Data Request No. 53.
[14] *Id.*
[15] Avista *2007 Electric Integrated Resource Plan*, August 31, 2007.
[16] 2006 Order to Dismiss PCORC Filing, ¶ 22.

- addressing the costs and benefits of the process based on performance in a test year; and
- analyzing the effect of an ERM/PTC process on the allowed rate of return.

Avista maintains that, without a PCORC, it will need to file a general rate case every year for the next several years.[17] It states that, with a PCORC, it will only need to file a general rate case every other year for the next several years. Avista bases its statements on its forecast of increases in non-power supply costs and increases in power supply costs. However, according to its responses to data requests, Avista:

- Has not prepared any projections comparing its future average retail rates without, and with, a PCORC.[18]
- Has not provided quantitative analyses demonstrating any of the following:
  - a. The level and frequency of rate adjustments with, and without, a PCORC.
  - b. The incremental increase in accuracy and timeliness of price signals with a PCORC relative to no PCORC.
  - c. The incremental improvement in customer ability to understand the factors causing rate increases with a PCORC relative to no PCORC.
  - d. The probability that Avista would file a PCORC for a rate adjustment of over 5 percent knowing that its remaining costs, not covered by the PCORC, had declined since it last general rate case.

[17] Avista Response to Public Counsel Data Request No. 177.
[18] Exhibit No. ___ (JRH-5). Avista Response to Public Counsel Data Request No. 22.

e. The incremental reduction in the administrative burden associated with establishing retail rates with a PCORC relative to no PCORC.[19]

**Q: Has Avista presented evidence demonstrating that the circumstances that it is facing are comparable to those that were facing Puget Sound Energy (PSE) when the Commission approved that utility's PCORC?**

A: No. In late 2001, PSE submitted filings requesting both a general increase in electric and gas rates, and an interim increase in its electric rates. The requests were consolidated in Docket Nos. UE-011570 and UG-011571.

As part of its filing, PSE requested the establishment of a power cost adjustment (PCA). PSE also asked for authority to file a PCORC. Based upon my understanding of that case, PSE was facing the need to acquire new generation resources very frequently at the time.[20] First, its load was growing rapidly and thus it was routinely acquiring additional, new resources and hence incurring additional costs. Second, its resource mix consisted of a significant quantity of purchased power and thus it was routinely replacing existing resources with new resources at new prices, in the form of expiring purchased power agreements (PPAs). The parties to the proceeding reached a settlement that included establishment of a PCA and a PCORC. The WUTC approved the PCA and

[19] Exhibit No. ___ (JRH-7), Avista Response to Public Counsel Data Request No. 28.
[20] *WUTC v. PSE*, Docket Nos. UE-011570 & UG-011571, Twelfth Supplemental Order: Rejecting Tariff Filing; Approving And Adopting Settlement Stipulation Subject To Modifications, Clarifications, And Conditions; Authorizing And Requiring Compliance Filing, June 20, 2002, Appendix A, Settlement Stipulation, Exhibit A: Power Cost Adjustment Mechanism.

PCORC in its Twelfth Supplemental Order, noting explicitly that the PCORC was an exception to the rule governing general rate increase filings.[21]

Avista has not demonstrated that it faces resource acquisition issues comparable to those that PSE was facing in 2001. Indeed, as noted above, it faces no substantial generation resource additions until the 2011-2014 time frame.

**Q: Is it reasonable for Avista to propose a PCORC that is modeled upon the existing PSE PCORC?**

A: No. Concerns have been raised regarding the design and operation of PSE's current PCORC. In response to those concerns the WUTC, in Order 07 in Docket No. UE-070565 issued August 2, 2007, approved a collaborative stakeholder review to consider whether the PSE PCORC should continue and, if so, whether its scope and timing should be changed.[22]

**Q: Do you recommend that Avista's request be rejected?**

A: Yes. Avista proposed a PCORC similar in design to the PSE PCORC, whose future operation and design are now under review. Avista has not demonstrated that establishment of a PCORC would provide material, balanced benefits to Avista's shareholders and ratepayers. In the absence of any such evidence, approval of the PCORC requested by Avista would represent an unjustified weakening of rate regulation in Washington and a move away from rates that are fair, just and reasonable.

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[21] *WUTC v. PSE*, Docket Nos. UE-011570 & UG-011571, Twelfth Supplemental Order, ¶ 25, citing Staff witness Merton Lott.
[22] *WUTC v. PSE*, Docket No. UE-070565, Order 07, Final Order Approving and Adopting Settlement, ¶ 22.

## IV. PROPOSED CHANGE IN ACCOUNTING TREATMENT FOR DSM PROGRAM COSTS AND REMOVAL OF FINANCIAL DISINCENTIVE

**Q: Please summarize the changes Avista is requesting with respect to DSM program costs.**

A: Avista proposed two changes related to its DSM program costs. First, the Company proposed to "capitalize" these costs and recover them or a set long-term period of approximately 10 years, in a manner similar to generation resource investments. Second, it proposed to recover the "lost margin" resulting from its electric DSM programs. Mr. Bruce Folsom presents these two proposals in his Direct Testimony.[23]

### A. Capitalizing DSM program costs

**Q: Please summarize the rationale that Avista has presented for capitalizing its DSM program expenses.**

A: Avista presents two main reasons for its proposal to "capitalize" its DSM program costs. First, the Company contends that this approach will make investments in DSM a more attractive investment, since it will be able to earn a return on those investments as it does with generation resources.[24] Second, it asserts this approach will produce a better match of customer costs and benefits over time, and thus improve intergenerational equity.[25] It also identifies a third alleged benefit, in that the proposed change would enable Avista to

[23] Exhibit No. ___ (BWF-1T), Folsom Direct, pp. 8-13.
[24] *Id.*, pp. 8-11.
[25] *Id.*, p. 9.

recover its accumulated under-recovery with no increase in the charges in Schedule 91 (the electric tariff rider) until 2011.[26]

**Q: Do those three reasons provide sufficient justification for the WUTC to allow Avista to capitalize its DSM program expenses?**

A: No. Those three reasons are not sufficient to offset the downsides of this proposal. As discussed further below, Avista's proposal does not provide a complete picture of the new context in which it will be operating, nor does it address the impacts of capitalizing DSM program costs on cost-effectiveness. In addition, the intergenerational equity and deferred balance issues do not justify this proposal.

**Q: Please comment on Avista's position that capitalizing DSM program costs will make DSM measures a more attractive investment than the current method of expensing those costs.**

A: Avista's position does not provide a complete picture of the context in which it is now, and will be, operating, and whether such a change in accounting treatment will cause any change in its pursuit of energy efficiency.

With the passage of Initiative 937 and increasing emphasis on controlling greenhouse gas emissions, Avista is facing a new context for meeting its obligation to provide reliable service at reasonable rates. In this new setting, DSM should be the most attractive investment for Avista, regardless of the accounting treatment applied to DSM program costs. This, in fact, appears to be the case. The preferred resource strategy

[26] *Id.*, p. 12.

through 2015 that Avista identifies in its recently released 2007 IRP consists of acquiring savings via efficiency every year, acquiring some additional renewable capacity, and acquiring up to 350 MW of CCGT capacity.[27] The IRP contains no discussion of the relative merits of either capitalizing or expensing DSM. Moreover, it is quite possible that Avista will acquire 275 MW of CCGT capacity via a power purchase contract, i.e. "expensing," rather than by purchasing the plant, i.e., capitalizing.[28]

There are a number of reasons why DSM is appealing relative to investments in conventional generation. Investments in conventional generation are not particularly attractive. Building conventional generation requires very large capital expenditures and carries significant financial risks. These include: risks that market conditions required to permit and build new generation will change substantially over the 5 to 10 years; risks of construction delays; cost overruns; operating problems; and, exposure to future regulation of greenhouse gases. Thus, acquisition of supply resources introduces additional risk into the company's risk profile, which tends to increase the equity ratio necessary to raise capital, decreasing shareholders' leverage and increasing their risk.

In contrast, cost-effective demand side resource choices generally face much lower levels of exposure to the risks listed above because they are modular, incremental, and open to continuous quality improvement. Moreover, cost-effective DSM choices are by definition the least cost choice. Therefore, choosing cost-effective DSM over generation and transmission whenever possible is not only beneficial to customers but is

[27] Avista 2007 Electric Integrated Resource Plan, August 31, 2007, Table 2, p. vi.
[28] *Id.*, p. ix.

also in the best interest of shareholders, regardless of whether a return is earned on those expenditures.[29]

**Q: Please comment on the impacts of capitalizing DSM program costs on the cost-effectiveness of DSM measures.**

A: If Avista is allowed to capitalize its DSM program costs, customers will pay more for every kwh of energy saved than they would if DSM costs were expensed. The higher payment results from spreading the recovery of these costs over a longer period, e.g. 10 years versus one year. During the longer recovery period Avista would earn a return of, and a return on, these costs. For example, at a carrying charge of 9.11 percent, the weighted average cost of capital approved in the Company's 2005 general rate case, a ten-year recovery period results in ratepayers paying twenty-two percent more for a given investment than they would if it were expensed.

This increased cost of DSM due to capitalization could change certain measures from being cost-effective to not being cost-effective. Such an impact would reduce the number of cost-effective DSM measures eligible for acquisition.

**Q: Please comment on the issue of intergenerational equity.**

A: Intergenerational equity can be a valid concern. However, intergenerational equity is not as much of a concern with respect to DSM program costs as it is with investments in generation and transmission capacity. The basic premise of intergenerational equity is that today's ratepayers should not be footing the bill for outlays that will benefit

[29] Other weaknesses in Avista's proposal to capitalize DSM were identified in Public Counsel discovery. *See* Exhibit No. ___ (JRH-8), Exhibit No. ___ (JRH-9), and Exhibit No. ___ (RH-10).

ratepayers for many years in the future. That is why investments in generation and transmission (G & T) capacity are depreciated over their economic lives.

However, DSM program costs are different than investments in G&T in that they are small investments that can be, and are, made every year. Therefore, if every generation of ratepayers is paying a similar amount for DSM program costs every year, year after year, the timing of the benefits generally matches the timing of the costs and it is not clear that there is a substantial intergenerational inequity.

**Q: Please describe the deferred balances currently associated with Schedules 91 and 191.**

A: Avista currently has a significant negative balance, i.e., a cumulative under-recovery, of its electric and gas DSM costs. As of the end of July 2007, the under-recovery was $3.0 million for electric DSM, and $1.3 million for gas DSM.[30] This under-recovery began developing in 2005 because, at that time, Avista increased its expenditures on DSM but did not file for a corresponding increase in its tariff rider surcharges. In fact, Avista has not increased the DSM portion of its electric tariff rider since 2001.[31]

The accrual of large negative balances means that ultimately, some portion of the funds collected from ratepayers through the tariff riders will be used to pay down the negative balance, rather than for existing programs. As the negative balances grow larger, it means that at some point, the portion of tariff rider funds allocated to the write-

[30] Avista Responses to Public Counsel Data Request No. 173 (electric DSM balance) and No. 172 (gas DSM balance).
[31] Avista Response to Public Counsel Data Request No. 7.

down of the under-recovery will increase.

I believe a more prudent approach would be for Avista to make an annual filing to adjust the tariff riders as necessary. This annual filing would provide for adjustments to the rider amounts to reflect: (1) any differences in actual costs from the prior year compared to budget projections, and (2) the anticipated DSM budget levels for the upcoming year. For example, Puget Sound Energy (PSE) has been making such an annual filing to adjust its conservation tariff riders as necessary for the past several years.

PSE's March 1, 2007 filing to adjust its electric conservation tariff rider states in part:

> [s]pecifically, the purpose of this filing is to revise the Electricity Conservation Rider charges upward in order to reflect actual costs and collections over the past year along with amounts budgeted for the upcoming year on conservation programs.[32]

An annual review of the tariff rider levels is consistent with Avista's stated goal that it believes it is important to manage its four DSM tariff rider accounts independently (electric and gas for Washington and Idaho).[33] The Company has also explained that "it is often difficult to project the number of participants, the magnitude of projects, especially in the commercial and industrial segment, as well as the timing and distribution. Natural gas projects especially tend to be more unevenly distributed than electric."[34]

[32] Docket No. UE-070424, Cover Letter to PSE Tariff filing, p. 1. *See also* PSE's companion gas filing, Docket No. UG-70427.
[33] Avista Response to Public Counsel Data Request No. 189.
[34] *Id.*

**Q: Will customers pay less if Avista recovers these balances under the proposed capitalization approach as opposed to recovering them through an increase in the surcharges under a continuation of its present accounting treatment?**

A: No. The relevant point to remember is that Avista will recover these balances from customers under either approach – there is no free lunch. Recognizing that fact, it will be less expensive for ratepayers in the long-run for Avista to continue with its current accounting approach using the tariff riders but to make annual filings with the Commission to adjust the rider amounts as necessary, as discussed above. Under its proposed capitalization approach, Avista could recover these under-recovery balances without increasing its charges in Schedule 91 until 2011. However, that approach will ultimately cost customers more. As explained above, if Avista capitalizes these amounts and recovers them over a longer period, ratepayers will end up paying more since they will ultimately reimburse Avista for the balance and also pay for Avista's financing costs over this longer period.

**Q: Is Avista subject to a formal annual review of its DSM program budgets, surcharge revenues, and expenditures?**

A: No. Avista meets with its External Energy Efficiency (Triple E) Board twice a year. However, it is not subject to a formal annual review of its DSM program budgets, surcharge revenues, and expenditures. Given the size of the deferred balances it has accumulated, it appears that Avista would benefit from a formal review, in the form of an annual filing with the Commission to adjust the rider amounts as necessary. As part of the partial stipulation, Avista has agreed to make such an annual filing with the Commission.

**Q: What do you recommend in response to Avista's proposal to capitalize its DSM program costs?**

A: I recommend that the Commission approve the partial stipulation. Under the stipulation, Avista's proposal to capitalize its DSM program costs is withdrawn. In addition, the stipulation provides that Avista will submit an annual filing to the WUTC for a formal review of its DSM program budget and tariff rider.

**B. Recovery of Lost Margin**

**Q: Please summarize Avista's request to recover fixed costs lost due to its electric DSM programs.**

A: Avista proposes a rate adjustment mechanism that would allow it to recover, between general rate cases, the estimated fixed costs that it asserts it no longer recovers due to reductions in electricity use by customers who participate in DSM programs. This lost margin recovery proposal can be characterized as a very narrow form of decoupling, one that is limited to adjusting rates to allow the utility to recover fixed costs lost due to DSM. Under the partial stipulation, Avista has withdrawn the proposal.

**Q: In Order 04 in Docket No. UE-050684, the WUTC specified the type of evidence that PacifiCorp should present, at a minimum, to support a request to establish an electric decoupling mechanism. Has Avista presented all of that evidence in this proceeding?**

A: No. In Order 04 in Docket No. UE-050684, the Commission identifies a minimum twelve pieces of information that should be provided in support of such a request.[35] Avista has failed to present several of those elements, including:

- rate of return implications;
- design of pilot test period and evaluation of the mechanism before determining whether to make it permanent;
- impact of the mechanism on low-income customers;
- identification of incremental conservation measures expected to be undertaken; and,
- development of an energy conservation target to be achieved through this mechanism, relative to baseline conservation programs currently in rates and the Company's Integrated Resource Plan (IRP).

**Q: Has Avista demonstrated that this proposal balances the interests of shareholders and ratepayers?**

A: No. This proposal again represents a departure from traditional ratemaking principles, as it is another example of single issue ratemaking. Specifically, Avista wishes to adjust its rates between general rate cases to recover its test year fixed costs per kwh lost due to DSM. As such this rate adjustment mechanism suffers from the same problems as its proposed PCORC.

[35] *WUTC v. Pacificorp*, Docket No. UE-050684, Order 04, Order Rejecting Tariffs, As Filed; Rejecting Stipulation on Net Power Costs; Rejecting, In Part, and Accepting, In Part, Stipulation on Temperature Normalization Adjustment; Determining Cost of Capital, ¶¶ 108-110.

Avista has not presented evidence to justify such a departure. First, Avista has not demonstrated that this change is necessary. Avista does not maintain that, if this proposal is rejected, it will face undue financial hardship or rates that will not be just and reasonable. Second, Avista has not demonstrated that its proposal balances the interests of shareholders and ratepayers. It provides no commitment to acquire more energy efficiency if this proposal is approved than it would have otherwise acquired. Further, the Company is not proposing to adjust its return on equity to reflect the reduction in cost recovery risk if this proposal were to be approved. Finally, it has not proposed an earnings test as part of this mechanism, which is a component of its gas decoupling mechanism.

**Q: Do you recommend that Avista's proposal to recover lost margin associated with its electric DSM programs be accepted?**

A: I recommend that the Commission approve the partial stipulation under which the lost margin recovery has been withdrawn.

## V. ADVANCED METER READING (AMR) PROGRAM

**Q: Please summarize Avista's AMR Program.**

A: Beginning in 2008, Avista proposes to install AMR devices on all natural gas meters and to upgrade all electric meters to new solid-state meters with AMR capability. This proposal is presented in the Direct Testimony of Avista witness Heather Cummins.[36]

**Q: Is Avista seeking recovery of that investment in this proceeding?**

[36] Exhibit No. ____ (HLC-1T), pp. 1-8. (Cummins Direct).

A: No. Avista states that it will request recovery of its AMR costs in a future proceeding accompanied by an estimate of all relevant costs and benefits.

**Q: What is your concern with Avista's proposed program?**

A: My concern is that Avista's proposed program entails major capital investments that may not be cost-effective. The Company's preliminary cost estimate for Phase I of this program, covering 2008 and 2009, is approximately $10.4 million. Its estimate for Phase II, covering 2010 through 2014, ranges from a low of $37 million to a high of to $61 million. Thus the total capital investment is expected to range between $47 million to $71 million.[37]

However, Avista has not provided a corresponding preliminary estimate to indicate that these investments are expected to be cost-effective. Given the possibility that the entire investment may not be cost-effective, I do not want Avista to, in any way, interpret silence in this proceeding as a form of implicit pre-approval or acceptance of its program. Therefore, I believe it is important for the Commission to remind Avista of the burden it will bear, in any future proceeding where it files for rate recovery. Specifically, that it must demonstrate that its investments are prudent, as well as used and useful. In addition, the Commission should state that nothing in this case constitutes acceptance of time-of-use (TOU) pricing or any other specific demand response program, and that Avista bears the burden of showing any proposed pricing scheme is fair, just, and reasonable. Finally, the Commission should re-state in its order the concerns it raised and

[37] *Id.*, p. 8.

factors it will consider regarding AMR deployment that it outlined in its Interpretive and Policy Statement issued in Docket No. UE-060649.[38]

**Q: What is the basis for your concern regarding the reasonableness of Avista's proposed program?**

A: My concern is based upon two basic points. First, Avista maintains that the primary justification for this capital investment is anticipated reductions in its costs due to increased operational efficiencies, in particular reductions in meter reading costs. However it has not provided a preliminary estimate of those anticipated benefits or addressed concerns with AMR technology. Second, Avista has indicated that it may try to justify cost recovery based in part on expected savings in supply costs by customers who opt for some version of TOU pricing but has not shown that TOU pricing would be fair, just, and reasonable, or would be cost-effective for ratepayers.

**Q: Has Avista provided a preliminary estimate of the reductions in operating expenses it expects from the proposed AMR program?**

A: No. Avista has presented estimates of the expected capital costs of Phase I and Phase II of its program but has not provided a corresponding estimate of the anticipated reductions in its operating costs. Therefore, the parties to this proceeding have not seen the economic justification underlying the proposal by Avista to implement this program in Washington. When asked for the internal economic analysis used to justify the program

[38] Interpretive and Policy Statement, Docket No. UE-060649, ¶33.

Avista responded that, as of September 12, 2007, the program had not received final approval under Avista's annual capital budgeting process.[39]

**Q: Did Avista provide the Idaho Public Utilities Commission with a preliminary estimate of the reductions in operating expenses it expected prior to starting its AMR program in that state?**

A: Yes. Before initiating a similar program in Idaho in 2005, Avista provided the Idaho Public Utilities Commission with a preliminary estimate of the anticipated benefits and costs of the program it was proposing for that state.[40] The anticipated benefits it quantified consisted of the various operational efficiencies Avista expected to achieve, which were primarily reductions in meter reading costs.

Avista presented levelized revenue requirements for its electric and gas operations respectively, with and without AMR.[41] These projections indicated that, on a standalone basis, electric meter reading with AMR was not cost-effective but gas meter reading with AMR was cost-effective. Specifically:

- electric meter reading with AMR would be 60 percent, or $188,703 per year, more expensive than without AMR; and,
- gas meter reading with AMR would be 60 percent less expensive, approximately $63,059 per year, than without AMR.[42]

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[39] Exhibit No. ____ (JRH-11), Avista Response to Public Counsel Data Request No. 187(b).
[40] Exhibit No. ____( JRH-12), Avista Response to Public Counsel Data Request No. 156.
[41] *Id.*
[42] *Id.*

Avista's projections also indicated that, in total, an AMR program for electric meter reading would increase Avista's electric utility revenue requirements in Idaho by 0.13 percent. It appears that the Idaho Commission based its decision to approve the AMR program on this comparison.

**Q: Please comment on the possibility that Avista will try to justify a portion of this investment on savings in supply costs by customers who opt for some form of TOU rates.**

A: According to Avista's Response to Public Counsel Data Request Numbers 34 and 56, Avista expects that reductions in its operational cost savings will only justify "a portion" of its investment.[43] If so, Avista may ultimately include as part of its justification for cost recovery of this investment the anticipated benefits to customers as well as to the Company. For example, Avista states that "other cost savings are expected through improved supply management" which it expects may result from the implementation of TOU or critical peak pricing.[44]

**Q: Has Avista indicated that TOU rates are likely to be cost-effective for most customers?**

A: No. On the contrary, in Docket UE-060649, Avista submitted comments to the Commission stating that TOU meters could be cost-effective for some customer classes,

[43] Exhibit No. ___ (JRH-13), and Exhibit No. ___ (JRH-14), respectively.
[44] Exhibit No. ___ (JRH-13), Avista Response to Public Counsel Data Request No. 34(a); and, Exhibit No. ___ (JRH-15), Avista Response to Public Counsel Data Request No. 161(a).

such as large industrial, but are not likely to be cost-effective for all customer classes:

> *[r]ecent and past analyses of TOU by Avista show it is likely not cost-effective for Avista to implement TOU for all customer classes*. The potential savings created by customers shifting their daytime demand into the night does not outweigh the cost of meter installation, software upgrades, and associated operational costs. TOU, however, could be cost-effective for our large industrial customers. These customers consume large quantities of power and already have sophisticated TOU-ready meters, making them potentially 'low-hanging fruit' (emphasis added). [45]

**Q: Has the WUTC identified the types of factors that will need to be considered when evaluating advanced metering proposals?**

A: Yes. In its Interpretive and Policy Statement issued in Docket No. UE-060649, the WUTC identified a number of factors that it might consider when examining advanced metering and rate design proposals. Those factors include, but are not limited to:

- Meter and installation costs.
- Administration costs including data storage, billing, and other associated functions to enable time-of-use pricing.
- Communication and marketing costs.
- Administrative savings associated with meter reading or other utility functions.
- System capacity and energy benefits: Value of operational changes in utilization of generation, transmission and distribution resources as a result of direct utility load-control, or reasonably expected customer actions to conserve or shift the timing of energy usage.

[45] Exhibit No. ___ (JRH-16), Avista Response to Public Counsel Data Request No. 160 Attachment A, p. 11.

- Equity in the distribution of any bill savings or costs among the customer classes, including the costs and benefits incurred or received by customers changing energy use patterns in response to time-of-use rate programs.
- Economic benefits that may be associated with the integration of new end-use loads such as recharging batteries in electrically powered vehicles.
- Economic benefits that may be associated with deferring investments in new delivery or generation capacity.
- Economic benefits that may be associated with additional information gathered through time-of-use metering systems (e.g., load research data).
- Environmental effects, positive or negative, of utility direct load-control programs, or customer load-shifting and conservation in response to time-of-use programs.
- Effects, if any, from advanced metering capability on existing consumer protection policies and programs relying on direct utility contact with customers.
- Protection of customer information and privacy.[46]

**Q: In that regard, has Avista identified all of the costs associated with implementing TOU rates.**

A: No. If Avista expects to justify this investment in advanced metering technology based on the asserted benefits of TOU pricing, it would have to include in its analysis the incremental data processing and billing system costs and any other incremental costs

[46] Interpretive and Policy Statement, Docket No. UE-060649, ¶33.

associated with operating such rate designs. To date, Avista has not identified the incremental data processing and billing system costs it would incur if it were to collect and process the type of hourly load data required for TOU or critical peak pricing.[47] Those incremental costs could be significant.[48] A recent survey of TOU pricing and demand-response programs prepared for the United States Environmental Protection Agency (EPA) notes that "a program's implementation costs can be substantial for both the utility and its customers, in some cases to the point of preventing the program's adoption."[49]

**Q: Has Avista addressed the other factors necessary to determine the prudence of AMR technology and TOU pricing?**

A: No. As noted above, the WUTC stated in its Interpretive and Policy Statement in UE-060649 that it would consider, among other things: the "equity in the distribution of any bill savings or costs among the customer classes;" "effects from advanced metering capability on existing consumer protection policies and programs relying on direct utility contact with customers;" and, "protection of customer information and privacy." Avista has addressed none of these issues.

In fact, Avista's proposed AMR program will likely warrant careful consideration of these issues. First, Avista indicated that it may seek TOU pricing. However, TOU

[47] Exhibit No. ___ (JRH-17), Avista Responses to Public Counsel Data Request No. 55(c) and (i).
[48] Exhibit No. ___ (JRH-17), Avista Response to Public Counsel Data Request No. 55, Exhibit No. ___ (JRH-18), Avista Response to Public Counsel Data Request No. 159, Exhibit No. ___ (JRH-19, Avista Response to Public Counsel Data Request No. 162.
[49] "A Survey Of Time-Of-Use (TOU) Pricing And Demand-Response (DR) Programs," *Energy & Environmental Economics* (July 2006), p. 36, *available at* www.epa.gov/cleanenergy/utilitypolicy.

billing programs are likely to impose disproportionate costs on limited-income residential customers because they are often unable to control their time of use. Also, customers who are confined to their homes because of medical needs and must maintain a certain level of heat or cold may be forced to pay high prices during periods of peak demand. Thus, elderly and disabled customers may see higher rates.

Second, Avista's proposed program includes remote connect and disconnect capabilities.[50] Remote disconnect technology is very likely to negatively impact limited-income and payment troubled customers. The Commission's rules, for example, provide that electric and natural gas utilities must allow customers to make a payment to a utility representative at the time of disconnection.[51] Avista is currently seeking to implement a remote disconnect and reconnect program for electric customers in certain rural and urban areas of Idaho. As part of this Idaho filing, Avista is seeking a waiver of certain utility customer relations rules.[52]

**Q: What do you recommend?**

A: I recommend that the Commission state that nothing in its order in this proceeding in any way constitutes a pre-approval of Avista's AMR program, and that Avista bears the financial risk that a future proceeding may determine that a portion of this investment is not prudent, or used and useful. The Commission should also state that Avista will also bear the burden of showing any TOU pricing system or other demand response program

[50] Exhibit No. ____, HLC-1T, p. 7. (Cummins Direct).
[51] WAC 480-100-128(6)(k) and WAC 480-90-128(6)(k) regarding disconnection notification.
[52] Idaho Public Utilities Commission, Case No. AVU-E-07-09. The Idaho PUC has issued an order seeking comment on the proposed pilot program by October 25, 2007. *See* Order No. 30437.

is fair, just, and reasonable. Finally, the Commission should remind Avista that it will have to address the full range of issues identified in the Interpretive and Policy Statement in order to justify any future proposal for cost recovery.

**Q: Does this complete your Direct Testimony?**

A: Yes.

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## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics, Inc.**, Cambridge, MA. *Senior Consultant,* 2006 to present. Analysis and expert testimony regarding planning, market structure, ratemaking and contracting issues in the electricity and natural gas industries.

**Charles River Associates (formerly Tabors Caramanis & Associates)**, Cambridge, MA.
*Principal,* 2004-2006.
*Senior Consultant,* 1998-2004.
Provided expert testimony and litigation support in several energy contract price arbitration proceedings, as well as in electric and gas utility ratemaking proceedings in Ontario, New York, Nova Scotia and New Jersey. Managed a major productivity improvement and planning project for two electric distribution companies within the Abu Dhabi Water and Electricity Authority. Analyzed a range of market structure and contracting issues in wholesale electricity markets.

**Tellus Institute**, Boston, MA.
*Vice President and Director of Energy Group*, 1997–1998.
Presented expert testimony on rates for unbundled retail services in restructured retail markets and analyzed the options for purchasing electricity and gas in those markets.
*Manager of Natural Gas Program,* 1986–1997.
Prepared testimony and reports on a range of gas industry issues including market structure, unbundled services, ratemaking, strategic planning, market analyses, and supply planning.

**Nova Scotia Department of Mines and Energy**, Halifax, Canada; 1981–1986
*Member*, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986
Member of a federal-provincial board responsible for regulating petroleum industry exploration and development activity offshore Nova Scotia.

*Assistant Deputy Minister of Energy* 1983–1986
Responsible for analysis and implementation of provincial energy policies and programs, as well as for Energy Division budget and staff. Directed preparation of comprehensive energy plan emphasizing energy efficiency and use of provincial energy resources. Senior technical advisor on provincial team responsible for negotiating and implementing a federal/provincial fiscal, regulatory, and legislative regime to govern offshore oil and gas. Directed analyses of proposals to develop and market natural gas, coal, and tidal power resources. Also served as Director of Energy Resources (1982-1983) and Assistant to the Deputy Minister (1981-1982.

**Nova Scotia Research Foundation**, Dartmouth, Canada, Consultant, 1978–1981
Edited Nova Scotia's first comprehensive energy plan. Administered government-funded industrial energy conservation program—audits, feasibility studies, and investment grants.

**Canadian Keyes Fibre**, Hantsport, Canada, Project Engineer, 1975–1977

**Imperial Group Limited**, Bristol, England, Management Consultant, 973–1975

## SELECTED TESTIMONY

Arkansas Public Service Commission 06-152-U, Entergy Arkansas, January 2007. Review of need for new load-following capacity.

Michigan Public Service Commission, Case No. U-14992, December 2006. Review the proposed sale of the Palisades nuclear plant and associated power purchase agreement.

Arizona Corporation Commission, Docket E-01345A-05-0816, August 2006 and September 2006. Review of Arizona Public Service hedging strategy and Base Fuel Recovery Amount.

Michigan Public Service Commission, Case No. U-14274-R, October 2006. Review the Resource Conservation Plan for purchases from Midland Cogeneration Venture Limited Partnership.

Illinois Commerce Commission, Docket No. 06-0540, October and December 2006. Review of service quality issues.

State Of Connecticut, Department Of Public Utility Control. Docket No. 06-03-04PH01, November 2006. Review gas supply strategy and proposed rate recovery.

Testimony before an arbitration panel in Toronto, Ontario, on behalf of a cogeneration plant regarding a dispute over a component of the price for steam under a 20-year contract. January 2006.

Testimony before an arbitration panel in Halifax, Nova Scotia, on behalf of Nova Scotia Power against Shell Canada regarding the determination of a new price under their ten year natural gas supply contract. October 2005.

State of New York, Public Service Commission, Case 00-M-0504, September 2002 and October 2002. Review of estimates of embedded costs of unbundled services (e.g., supply, distribution, metering, billing), and associated proposed rates, filed by Consolidated Edison of New York and New York State Electric and Gas respectively.

State of New Jersey Board of Public Utilities, BPU Docket GM00080564, April 2001. Analysis of the proposed transfer of gas supply and capacity contracts from Public Service Electric and Gas to an unregulated affiliate, and the full requirements supply contract associated with that transfer.

Nova Scotia Utility and Review Board, NSUARB-NG-SEMPRA-SEM-00-08, February 2001. Review of proposed distribution service tariff, including methodology for setting market-based rates, rates for large customers and default supply.

State of New Jersey Board of Public Utilities, BPU Docket EX99009676, March 2000. Analysis of the design and pricing of customer account services to be offered by utilities on an unbundled basis.

United States of America Bonneville Power Administration, BPA Docket WP-02, (TCA #391), November 1999. Functionalization of Communication Plant.

South Carolina Public Service Commission, 99-006-G, South Carolina Electric and Gas, October 1999. Reasonableness of purchased gas costs.

State of New Jersey Board of Public Utilities, BPU Dockets GO99030122–GO99030125, July 1999 and sur-rebuttal September 1999. Analysis of service unbundling policies and rates proposed in filings of Public Service Electric & Gas, South Jersey Gas, New Jersey Natural Gas, and Elizabethtown Gas.

Maine Public Utilities Commission, Docket 97-393, Northern Utilities Inc., September 1998 and rebuttal December 1998. Review of request for approval of rate redesign and partial unbundling proposal.

Pennsylvania Public Utility Commission, R-00984281, A-12250F0008, Peoples Natural Gas, May 1998. Analysis of the reasonableness of 1998 1307(f) filing and proposal to transfer production assets to affiliate.

State of New Jersey, Board of Public Utilities, BPU E09707 0465, OAL PUC-7309-97, BPU E09707 0464, OAL PUC-7310-97, January 1998 with Supplemental and Sur-rebuttal March 1998. Analysis of rate unbundling filing of Rockland Electric Company.

State of New Jersey, Board of Public Utilities, BPU EO9707 0459, OAL PUC- 7308-97, BPU E09707 0458, OAL PUC-7307-97, November 1997. Analysis of rate unbundling filing of Jersey Central Power & Light Company d/b/a GPU Energy.

Pennsylvania Public Utility Commission, R-00963858, Equitable Gas Company, June 1997 with rebuttal and sur-rebuttal July 1997. Analysis of the reasonableness of rate structure proposals.

Pennsylvania Public Utility Commission, R-00973896 and A-0012250F-0007, (Tellus 97-065) Peoples Natural Gas Company, May 1997. Review of 1997 1307(f) filing, proposal to transfer producing assets to CNG Producing Company, and proposed Migration Rider.

South Carolina Public Service Commission, 97-009-G, South Carolina Pipeline Corporation, April 1997. Reasonableness of proposal to acquire an additional 75,700 Mcf/day of capacity from Transco.

Federal Energy Regulatory Commission, RP95-197-001, RP97-71-000, March 1997. Review of proposed rolled-in ratemaking for Leidy Line incremental facilities.

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Maine Public Utilities Commission, 95-480, 95-481, April 1996, proposed Precedent Agreement between Northern Utilities, Inc. and Granite State Gas Transmission, Inc. for LNG Storage Service (95-480); and PNGTS for Transportation Service (95-481).

Rhode Island Public Utilities Commission, 2025, November 1995, Settlement Agreement reached between ProvGas and the Division of Public Utilities and Carriers.

Pennsylvania Public Utility Commission, R-953406, October 1995, application of T.W. Phillips Gas and Oil Co. for increase in rates and changes in rate and tariff design.

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Pennsylvania Public Utility Commission, R-953316, May 1995, purchased gas costs and gas procurement of Columbia Gas of Pennsylvania with Supplemental Direct Testimony and Sur-Rebuttal Testimony.

Pennsylvania Public Utility Commission R-943252, (Tellus 95-039), May 1995, application of Peoples Natural Gas Company for increase in rates and changes in rate and tariff design.

South Carolina Public Service Commission, 94-007-G, (Tellus 95-038), April 1995, reasonableness of 1994 purchased gas costs of South Carolina Pipeline Corporation.

Pennsylvania Public Utility Commission R-943207, (Tellus 95-014), March 1995, 1995 Purchased Gas Adjustment filing of National Fuel Gas Distribution Corp.

Pennsylvania Public Utility Commission, R-00943063, (Tellus 94-271), December 1994, design of FERC Order 636 transition cost tariff of UGI Utilities, Inc.

South Carolina Public Service Commission, 94-008-G, (Tellus 94-173), October 1994, 1994 Purchased Gas Adjustment of South Carolina Electric and Gas Co.

Oklahoma Corporation Commission, PUD 920, 001342, (Tellus93-250) September 1994, reasonableness of gas supply strategy of Public Service of Oklahoma, including payments to Transok, Inc. for transportation and agency services and rate mechanism for cost recovery. November 1994 Rebuttal testimony in above docket.

Pennsylvania Public Utility Commission, R-943078, (Tellus 94-155), September 1994, Market Sensitive Sales Service proposed by Pennsylvania Gas and Water Company (PG&W).

Massachusetts Department of Public Utilities, D.P.U. 93-141-A, (Tellus 94-184), September 1994, response to questions regarding policies on interruptible transportation and capacity release in DPU IT/CAPACITY RELEASE SCOPE document dated June 16, 1994. October 1994 Comments in above docket.

Hawaii Public Utilities Commission, 7259, (Tellus 94-020), August 1994, HELCO'S proposed DSM programs for competitive energy end-use markets and its multi-attribute analysis.

Pennsylvania Public Utility Commission, R-00943066, (Tellus 94-135), July 1994, 1994 Purchased Gas Adjustment of Pennsylvania Gas and Water Company. August 1994 Sur-rebuttal testimony in above docket.

Pennsylvania Public Utility Commission, R-942993, R-942993 C0001-C0004, (Tellus 94-110), May 1994, proposal of Pennsylvania Gas and Water Company for recovery of FERC Order 636 transition costs. May 1994 Rebuttal testimony in above docket.

Pennsylvania Public Utility Commission, R-943001, (Tellus 94-018), May 1994, application of Columbia Gas of Pennsylvania for an increase in rates and changes in rate design, specifically Negotiated Sales Service.

Pennsylvania Public Utility Commission, R-943029, (Tellus 94-093), May 1994, 1994 Purchased Gas Adjustment of Columbia Gas of Pennsylvania.

Pennsylvania Public Utility Commission, R-932866, R-932915, (Tellus 93-243), 1994, Direct and rebuttal testimony on application of Peoples Natural Gas Company for increase in rates and changes in rate design. March 1994 Rebuttal testimony in above docket.

Kansas Corporation Commission, 180,056-U, (Tellus 92-105), February 1994, Oral Testimony on IRP Rules for gas utilities.

Arizona Corporation Commission, E-1032-93-111, (Tellus 93-099), December 1993, application of Citizens Utility Company, Arizona Gas Division, for an increase in rates, and changes in rate design. January 1994 Sur-rebuttal testimony in above docket.

Hawaii Public Utilities Commission, 7257 (Tellus 93-144B5), December 1993, proposed DSM programs for end-use markets, specifically HECO's residential sector water heating program.

Hawaii Public Utilities Commission, 7261 (Tellus 93-171), September 1993, GASCO IRP. December 1993 Rebuttal testimony in above docket.

Pennsylvania Public Utility Commission, R-932655, R-932655 C001, R-932655 C002, (Tellus93-149), September 1993, balancing service charge proposed by PG&W.

Pennsylvania Public Utility Commission, R-932676, (Tellus 93-092), July 1993, 1993 Purchased Gas Adjustment filing of Pennsylvania Gas and Water Company. July 1993 Rebuttal Testimony in above docket.

Public Utilities Commission of Rhode Island, 2025, (Tellus 93-018), April 1993, Providence Gas Company Integrated Resource Plan.

Pennsylvania Public Utility Commission, I-900009, C-913669, (Tellus 91-074), March 1993, Equitable's charges for transportation service and cost allocation methods in general.

Arkansas Public Service Commission, 92-178-U, (Tellus 92-014), August 1992, Stipulation and Agreement concerning gas cost and purchasing practices issues in Dockets No.91-093-U (Arkla Energy Resources) and No. 92-032-U (Arkansas Louisiana Gas).

Colorado Public Utilities Commission, 91R-642EG, (Tellus 91-203), August 1992, Draft, proposed gas integrated resource planning (IRP) rule.

Pennsylvania Public Utility Commission, R-00922324, (Tellus 92-117), July 1992, 1992 Purchased Gas Adjustment filing of PG&W. July 1992 Supplemental Testimony in above docket.

Pennsylvania Public Utility Commission, R-922180, (Tellus 92-039), May 1992, application of Peoples Natural Gas Company for an increase in rates and accompanying changes, in rate design. June 1992 Rebuttal Testimony in above docket. June 1992 Sur-rebuttal Testimony in above docket

Michigan Public Commission, U-10030, (Tellus 91-120), April 1992, 1992 Gas Cost Recovery Plan submitted Service by Consumers Power Company, specifically the role of demand-side management as a resource in five-year forecast and supply plan.

Pennsylvania Public Utility Commission, R-912140, (Tellus 92-038), March 1992, review of 1992 Purchased Gas Adjustment of T.W. Phillips.

Federal Energy Regulatory Commission, RP91-161-000 et al., RP91-160-000 et al., (Tellus 91-175), February 1992, review of cost allocation and rate design issues in rate case application of Columbia Gas Transmission and Columbia Gulf Transmission (on behalf of PA OCA).

Arkansas Public Service Commission, 91-093-U, (Tellus 92-014), February 1992, establishment of a base cost of gas for Arkla Energy Resources (AER), modification of Purchased Gas Adjustment (PGA). June 1992 Sur-rebuttal Testimony in above docket.

New Hampshire Public Utilities Commission, DR90-183, (Tellus 91-164), January 1992, role of embedded cost-of-service studies, level of customer charges, seasonal differential in commodity rates; and class revenue requirements (Energy North Natural Gas, Inc.).

Arizona Corporation Commission, U-1551-89-102 & U-1551-89-103, U-1551-91-069, (Tellus 90-203) September 1991, Gas Procurement Practices and Purchased Gas Costs (January 1986 – November 1990) of Southwest Gas Corporation. December 1991. Rebuttal Testimony in above docket.

Maryland Public Service Commission, 8339, (Tellus 91-79), July 1991, cost allocation and rate design issues in rate case application of Baltimore Gas and Electric Company.

Public Utilities Commission of Rhode Island, 1727, (Tellus 90-135), June 1991, review of gas procurement practices of Bristol and Warren Gas Company. Sept. 1991, (Tellus 91-165), Supplemental Direct Testimony in above docket.

New Mexico Public Service Commission, 2367, (Tellus 91-030), June 1991, analysis of gas transportation policies proposed by Gas Company of New Mexico.

Pennsylvania Office of Consumer Advocate, R-911889, (Tellus 91-025), March 1991, review of gas supply strategy and purchasing practices of T.W. Phillips.

Michigan Public Service Commission, U-9752, (Tellus 90-099), March 1991, review of 1991 Gas Cost Recovery Plan submitted by Michigan Gas Company to Michigan PSC.

Arkansas Public Service Commission, 90-036-U, (Tellus 90-041), August 1990, reasonableness of certain gas supply contracts, of Arkla, Inc. and its various subsidiary companies including the Arkla-Arkoma transactions. September 1990. Prepared Rebuttal Testimony.

Arizona Corporation Commission, U-1240-90-051, (Tellus 90-059), August 1990, application of Southern Union Gas Company for a change in tariffs.

Public Utility Commission of Utah, 89-057-15, (Tellus 89-242), July1990, Cost Allocation and Rate Design, Mountain Fuel Supply. August 1990 Rebuttal and Sur-rebuttal Testimony.

Pennsylvania Public Utility Commission, R-901595, (Tellus 90-043), June 1990, application of Equitable Gas Company for changes to its tariffs.

West Virginia Public Service Commission, 90-196-E-GI, 90-197-E-GI, (Tellus 90-025), May 1990, expanded Net Energy Cost, coal supply strategy and contracting practices, APS.

Pennsylvania Public Utility Commission, R-891572, (Tellus 90-08B), March 1990, Purchased Gas Costs and Gas Procurement, T.W. Phillips Gas and Oil Co.

Public Utilities Commission of Colorado, 89R-702G, (Tellus 89-30A), January 1990, policies and rules for gas transportation service offered by public utilities regulated by the Commission. January 1990, (Tellus 89-30B), Supplemental Testimony

Arizona Corporation Commission, U-1551-89-102 and U-1551-89-103, (ESRG 89-01), October 1989, Regulatory Oversight of Purchased Gas Costs.

Public Utilities Commission of Rhode Island, 1938, (ESRG 89-139), October 1989, Sales Forecast, Cost Allocation, Rate Design, Narragansett Electric Company.

Pennsylvania Public Utility Commission, R891293, (ESRG 89-92), July 1989, Purchased Gas Costs & Gas Procurement, Pennsylvania Gas and Water. July 1989 Rebuttal Testimony.

Pennsylvania Public Utility Commission, R891236, (ESRG 89-48), May 1989, Take-or-Pay Cost Recovery, Columbia Gas of Pennsylvania.

New Jersey Board of Public Utilities, GR 88070-877, (ESRG 88-150A), February 1989, Take-or-Pay Cost Recovery, Public Service Electric and Gas.

New Jersey Board of Public Utilities, GR 88080-913-Phase II (ESRG 88-150C), February 1989, Take-or-Pay Cost Recovery, South Jersey Gas Company.

New Jersey Board of Public Utilities, GR 88081-019-Phase II (ESRG 88-150D), February 1989, Take-or-Pay Cost Recovery, Elizabethtown Gas Company.

New Jersey Board of Public Utilities, 88080913, (ESRG 88-102), December 1988, Take-or-Pay Cost Recovery, Elizabethtown Gas Company.

Montana Public Service Commission, 87.7.33, 88.2.4, 88.5.10, 88.8.23, (ESRG 88-117), December1988, Gas Procurement, Transportation Service, Gas Adjustment Clause, Montana-Dakota Utilities Company.

New Jersey Board of Public Utilities, GR 88081-019, (ESRG 88-103), November1988, Take-or-Pay Cost Recovery, South Jersey Gas Company.

New Jersey Board of Public Utilities, GR 88070-877 (ESRG 88-89), October 1988, Take-or-Pay Cost Recovery, Public Service Electric and Gas.

Public Service Commission of District of Columbia, Formal Case 874, (ESRG88-58), September 1988, Gas Acquisition, Gas Cost Allocation, Take-or-Pay Cost, Regulatory Oversight; District of Columbia Natural Gas.

Illinois Commerce Commission, 88-0103, (ESRG 88-68), July 1988, Take-or-Pay Cost Recovery.

Public Service Commission of West Virginia, 240-G, (ESRG 88-42), June 1988, Gas Transportation Rate Design.

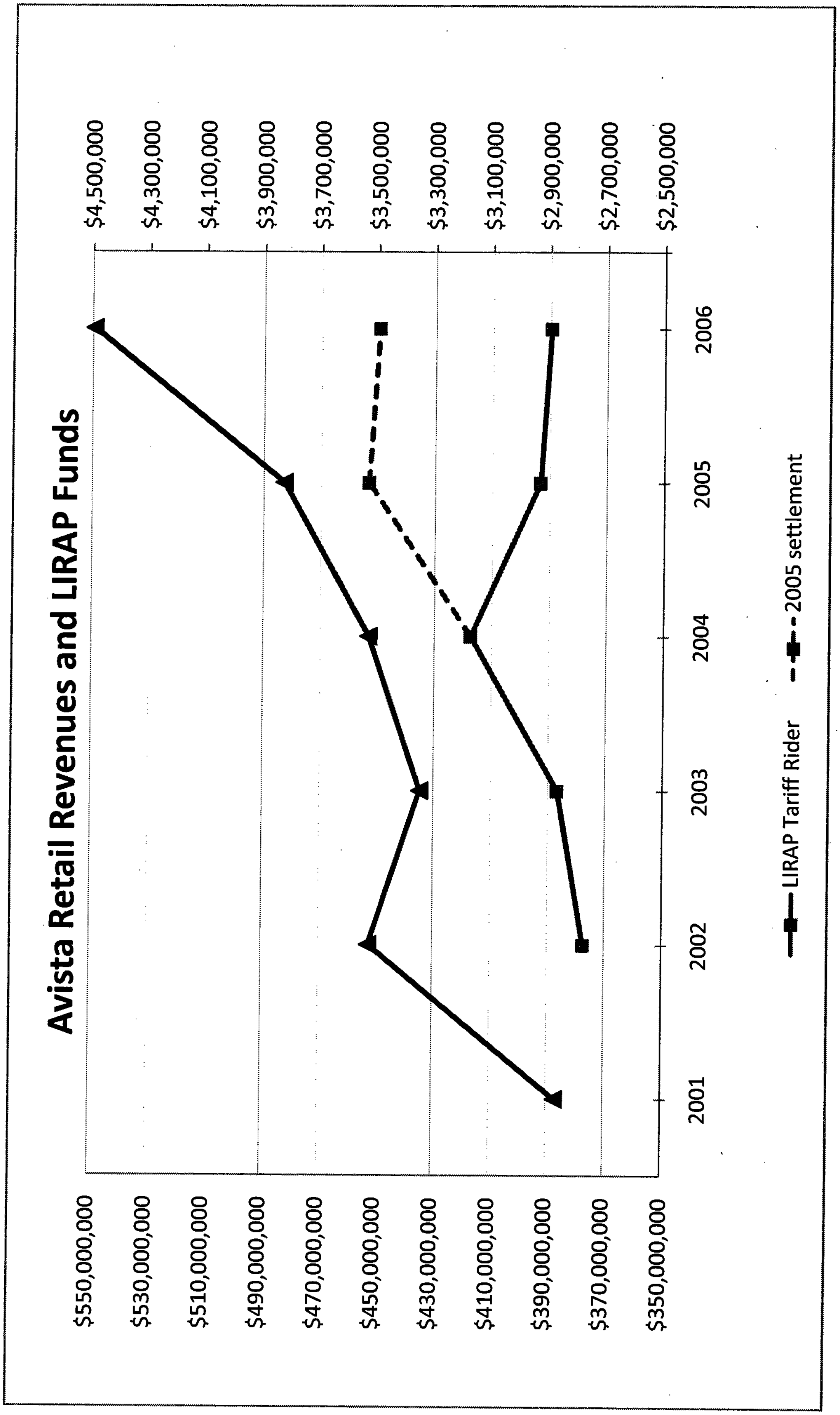
Pennsylvania Public Utility Commission, R-880958, (ESRG 88-29), June 1988, Purchased Gas Adjustment, Pennsylvania Gas & Water Company.

Public Service Commission of Utah, 86-057-07, (ESRG 87-111), March 1988, Gas Transportation Rate Design; Mountain Fuel Supply.

South Carolina Public Service Commission, 83-126-G, 86-217-G, (ESRG 87-106), January 1988, Gas Supply and Rate Design, Piedmont Gas Company.

South Carolina Public Service Commission, 87-227-G, (ESRG 87-64), September 1987, Gas Supply and Rate Design, South Carolina Electric and Gas.

Arizona Corporation Commission, U-1345-87-069, (ESRG 87-48), September 1987, Fuel Adjustment Clause.


Avista Retail Revenues and LIRAP Funds
$550,000,000
$530,000,000
$510,000,000
$490,000,000
$470,000,000
$450,000,000
$430,000,000
$410,000,000
$390,000,000
$370,000,000
$350,000,000
$4,500,000
$4,300,000
$4,100,000
$3,900,000
$3,700,000
$3,500,000
$3,300,000
$3,100,000
$2,900,000
$2,700,000
$2,500,000
2001
2002
2003
2004
2005
2006
LIRAP Tariff Rider
2005 settlement

# AVISTA UTILITIES Revenues and Funding of LIRAP and DSM in WA
## 2001 through 2006 Actual and 2008 Projected

| | Electric | | | | | | |
|---|---|---|---|---|---|---|---|
| | Year | Retail Revenues | Revenues from Surcharges | | | | |
| | | | LIRAP Program Year | DSM | Total LIRAP & DSM | LIRAP as % of Revenue | DSM as % of Revenue |
| Actual | 2000 | $239,430,134 | $0 | $3,442,717 | $3,442,717 | 0.0000% | 1.4379% |
| | 2001 | $247,334,094 | $1,090,934 | $3,982,823 | $5,073,757 | 0.6616% | 1.6103% |
| | 2002 | $297,896,096 | $1,750,178 | $4,386,478 | $6,136,656 | 0.5875% | 1.4725% |
| | 2003 | $308,402,455 | $1,780,400 | $4,358,910 | $6,139,310 | 0.5773% | 1.4134% |
| | 2004 | $313,077,964 | $1,806,727 | $4,981,596 | $6,788,323 | 0.5771% | 1.5912% |
| | 2005 | $314,452,716 | $1,841,177 | $4,387,492 | $6,228,669 | 0.5855% | 1.3953% |
| | 2006 | $349,407,806 | $1,898,898 | $4,683,069 | $6,581,967 | 0.5435% | 1.3403% |
| Avista Request | 2008 | $373,068,000 | | | | | |

| | Gas | | | | | | |
|---|---|---|---|---|---|---|---|
| | Year | Retail Revenues | Revenues from Surcharges | | | | |
| | | | LIRAP Program Year | DSM | Total LIRAP & DSM | LIRAP as % of Revenue | DSM as % of Revenue |
| Actual | 2000 | | $0 | $0 | | | |
| | 2001 | $139,782,957 | $420,860 | $528,548 | $949,408 | 0.4516% | 0.4183% |
| | 2002 | $154,660,252 | $1,024,270 | $654,861 | $1,679,131 | 0.6623% | 0.4234% |
| | 2003 | $126,369,285 | $1,087,225 | $941,498 | $2,028,723 | 0.8604% | 0.7450% |
| | 2004 | $140,002,078 | $1,366,959 | $1,670,728 | $3,037,687 | 0.9764% | 1.1934% |
| | 2005 | $168,454,740 | $1,091,078 | $1,327,318 | $2,418,396 | 0.6477% | 0.7879% |
| | 2006 | $200,081,231 | $997,592 | $1,034,222 | $2,031,814 | 0.4986% | 0.5169% |
| Avista Request | 2008 | $ 202,352,000 | | | | | |

| | Electric + Gas | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Retail Revenues | Revenues from Surcharges | | | | | BUDGETS | | |
| | Year | | LIRAP Program Year | DSM | Total LIRAP & DSM | LIRAP as % of Revenue | DSM as % of Revenue | LIRAP | LIRAP as % of Revenue | Low Income DSM |
| Actual | 2000 | | | | | | | | | |
| | 2001 | $387,117,051 | $1,511,794 | $4,511,371 | $6,023,165 | 0.5858% | 1.2894% | $ 2,731,616 | 0.71% | |
| | 2002 | $452,556,348 | $2,774,448 | $5,041,339 | $7,815,787 | 0.6131% | 1.1140% | $ 2,678,068 | 0.59% | $ 929,589 |
| | 2003 | $434,771,741 | $2,867,625 | $5,300,408 | $8,168,033 | 0.6596% | 1.2191% | $ 3,158,220 | 0.73% | $ 929,589 |
| | 2004 | $453,080,043 | $3,173,686 | $6,652,324 | $9,826,010 | 0.7005% | 1.4682% | $ 3,039,672 | 0.67% | $ 929,589 |
| | 2005 | $482,907,456 | $2,932,255 | $5,714,810 | $8,647,065 | 0.6072% | 1.1834% | $ 3,157,635 | 0.65% | $ 931,589 |
| | 2006 | $549,489,038 | $2,896,490 | $5,717,291 | $8,613,781 | 0.5271% | 1.0405% | $ 3,846,394 | 0.70% | $ 866,706 |
| Avista Request | 2008 | $575,420,000 | | | | | | $ 2,946,394 | 0.51% | $ 666,706 |

Sources: Retail Revenues - Avista Response to Public Counsel Data Request 164, supplement, p. 1 of 3
LIRAP Budget - LIRAP Annual Reports, UE-010436 & UG-010437
DSM Surcharge Revenue - Avista Responses to Public Counsel Data Request 6 and 9
Low Income DSM - Avista Response to PC Data Request 167, supplement

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 07/9/2007 |
| CASE NO: | UE-070804/UG-070805 | WITNESS: | Kelly Norwood |
| REQUESTER: | Public Counsel | RESPONDER: | Kelly Norwood |
| TYPE: | Data Request | DEPT: | State & Fed. Reg. |
| REQUEST NO.: | PC -22 | TELEPHONE: | (509) 495-4267 |

**REQUEST:**

**Re: Testimony of Kelly Norwood, page 3, lines 5 to 21.**

Please provide the following:

a. All projections prepared by, or for, Avista comparing its future base power supply and transmission related revenues, expenses and rate base with, and without, a PCORC. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.

b. All projections prepared by, or for, Avista comparing future average retail rates, including the ERM, with, and without, a PCORC. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.

**RESPONSE:**

a. Avista has not prepared projections comparing its future base power supply and transmission related revenues, expenses and rate base with, and without, a PCORC. On pages 3 – 5 of Mr. Norwood's Direct Testimony he identifies a number of generating resource-related cost changes that are expected to occur in the next several years, such as upgrades to hydro-electric resources, relicensing of the Spokane River hydro-electric projects, mitigation of dissolved gas at Cabinet Gorge, and acquisition of additional renewable resources to comply with the requirements of Initiative 937. These items, among others, are in addition to the upcoming need for additional resources to serve retail load requirements. Although the timing and costs for some of these changes are somewhat predictable, many others are not, and thus specific projections of changes in costs with and without a PCORC may provide little useful information. As Mr. Norwood explained in his testimony, one of the benefits from the PCORC process is the opportunity to provide more timely recovery of these types of changes in costs, in a manner that is beneficial to all stakeholders. Also see the Company's response to Public Counsel Data Request No. 24, where it identifies the future expected generating resource-related costs that were included in the most recent financial forecast.

b. Avista has not prepared projections comparing future average retail rates, including the ERM, with, and without, a PCORC. Also see the response in (a.) above.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 5/30/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Kelly Norwood |
| REQUESTER: | WUTC Staff | RESPONDER: | Clint Kalich |
| TYPE: | Data Request | DEPT: | Energy Resources |
| REQUEST NO.: | Staff - 53 | TELEPHONE: | (509) 495-4532 |

**REQUEST:**
Please provide a detailed analysis by year from 2006 to 2020 of the generation resource additions that Avista proposes would be recovered through a PCORC mechanism. This information should be referenced to Avista's most recent IRP. Please indicate the total dollars per project per year that Avista would seek recovery for through this mechanism. These calculations should be shown with and without renewable resources.

**RESPONSE:**
Please see the attached spreadsheet (file name: Staff_DR_53-Attachment A.xls) that provides the annual acquisition estimate from the forthcoming 2007 Integrated Resource Plan (IRP). The resources included in the spreadsheet were shared with our IRP Technical Advisory Committee on April 25, 2007.

There are also several other areas that could be recovered on a more frequent basis through a PCORC mechanism. These yet-to-be determined costs include such items as dissolved gas mitigation expenses at Cabinet Gorge, Spokane River Relicensing, and compensation to the Coeur d'Alene tribe for the use of the lake (Storro Testimony p. 13 – 18); as well as power supply cost issues including fuel prices, wholesale market prices, and loads.

Avista Response to Staff - 53
Attachment A

# 2007 Draft IRP Resource Acqusition Schedule

| | Nameplate Capacity (MW) | | | | Costs ($millions) | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Wind | Other Renewables | Gas CCCT | Total | Wind | Other Renewables | Gas CCCT | Total |
| 2006 | - | - | - | - | - | - | - | - |
| 2007 | - | - | - | - | - | - | - | - |
| 2008 | - | - | - | - | - | - | - | - |
| 2009 | - | - | - | - | - | - | - | - |
| 2010 | - | - | - | - | - | - | - | - |
| 2011 | - | 20.00 | 280.00 | 300.00 | - | 9.58 | 43.44 | 53.02 |
| 2012 | - | 10.00 | - | 10.00 | - | 16.49 | 47.30 | 63.79 |
| 2013 | - | - | - | - | - | 16.66 | 45.64 | 62.30 |
| 2014 | 100.00 | 5.00 | 70.00 | 175.00 | 28.28 | 18.49 | 55.58 | 102.35 |
| 2015 | - | - | - | - | 30.95 | 18.02 | 55.06 | 104.03 |
| 2016 | 100.00 | - | - | 100.00 | 65.53 | 16.98 | 53.14 | 135.65 |
| 2017 | 100.00 | - | - | 100.00 | 105.08 | 15.96 | 51.28 | 172.33 |
| 2018 | - | - | - | - | 102.40 | 14.97 | 49.49 | 166.85 |
| 2019 | - | - | - | - | 94.31 | 14.00 | 47.73 | 156.04 |
| 2020 | - | 10.00 | 81.20 | 91.20 | 88.24 | 21.00 | 61.86 | 171.09 |
| 2006-20 Total | 300.00 | 45.00 | 431.20 | 776.20 | 514.79 | 162.13 | 510.53 | 1,187.45 |

# AVISTA CORP.
## RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 07/11/2007 |
| CASE NO: | UE-070804/UG-070805 | WITNESS: | Kelly Norwood |
| REQUESTER: | Public Counsel | RESPONDER: | Kelly Norwood |
| TYPE: | Data Request | DEPT: | State & Fed. Reg. |
| REQUEST NO.: | PC -28 | TELEPHONE: | (509) 495-4267 |

**REQUEST:**

**Re: Testimony of Kelly Norwood, page 7, line 27 to page 8, line 19.**

Please provide all research and/or quantitative projections prepared by, or for, Avista of the following:

a. The level and frequency of rate adjustments with, and without, a PCORC.

b. The incremental increase in accuracy and timeliness of price signals with a PCORC relative to no PCORC.

c. The incremental improvement in customer ability to understand the factors causing rate increases with a PCORC relative to no PCORC.

d. The probability that Avista would file a PCORC for a rate adjustment of over 5% knowing that its remaining costs, not covered by the PCORC, had declined since it last generate rate case.

e. The incremental improvement in its financial condition with a PCORC relative to no PCORC.

f. The incremental reduction in the administrative burden associated with establishing retail rates with a PCORC relative to no PCORC.

**RESPONSE:**

a. Please see the Company's responses to WUTC Staff Request No. 60, and Public Counsel Request Nos. 26 and 27.

b. Please see the Company's responses to WUTC Staff Request Nos. 58 and 62, and Public Counsel Request No. 27.

c. Please see the Company's responses to WUTC Staff Request Nos. 63 and 64, and Public Counsel Request No. 27.

d. In Avista's CONFIDENTIAL response to WUTC Staff Request No. 180C, it provided a copy of its most recent financial forecast. That forecast shows a need for additional rate relief for the next several years. That need for rate relief is driven not only by cost items that would be included in the PCORC, but also other cost categories that are not included in the PCORC, such as administrative & general, certain operation & maintenance expenses, and additional capital investment excluded from the PCORC. No other specific research or projections have been prepared.

e. Please see the Company's response to WUTC Staff Request No. 67.

f. Please see the Company's responses to WUTC Staff Request No. 68, and Public Counsel Request No. 27.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | | |
|---|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/16/2007 | |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Bruce Folsom | |
| REQUESTER: | Public Counsel | RESPONDER: | Lori Hermanson | (509) 495-4658 |
| TYPE: | Data Request | RESPONDER: | Jon Powell | (509) 495-4047 |
| REQUEST NO.: | PC - 39 | DEPT: | Energy Solutions | |

**REQUEST:**
Please provide all projections and analyses prepared by, or for, Avista of the incremental increase in matching of customer costs and benefits over time under its proposed changes in regulatory and accounting treatment of DSM funding. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.

**RESPONSE:**
Avista has not prepared analyses of incremental funding under the proposed regulatory and accounting treatment.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | | |
|---|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/13/2007 | |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Bruce Folsom | |
| REQUESTER: | Public Counsel | RESPONDER: | Lori Hermanson | (509) 495-4658 |
| TYPE: | Data Request | RESPONDER: | Jon Powell | (509) 495-4047 |
| REQUEST NO.: | PC - 38 | DEPT: | Energy Solutions | |

**REQUEST:**
Please provide the following:

a. All projections and analyses prepared by, or for, Avista comparing its future funding of DSM with, and without, a combination of capitalizing and expensing its DSM expenditures. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.
b. All projections and analyses prepared by, or for, Avista comparing its future funding of DSM with, and without, a predefined minimum capital budget. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.
c. All projections and analyses prepared by, or for, Avista comparing its future funding of DSM with, and without, an electric fixed cost recovery charge. Please include all supporting input assumptions, calculations and workpapers. If Avista has not prepared such a quantitative analysis or projection please explain why not.

**RESPONSE:**

a. Please see Attachment A, page 1, column I for electric and page 2, column H for natural gas, for comparison of future DSM funding vs. capitalizing and expensing.

b. The IRP process determines cost-effectiveness and the minimum funding level. Current funding is insufficient to meet this minimum level and therefore spending will go beyond the minimum level. Please see Attachment B, for 20 year projections of cost effective acquisitions.

c. Please see Attachment A, which shows the funding requirements in columns b, d, & e. No additional analysis has been completed.

Please also see the attached documents, Attachment C & D, that address utility cost recovery of DSM such as capitalization and fixed cost recovery.

**PC_DR-38 - Attachment A**
**Avista Utilities**
**Washington - Electric**
**Estimated Schedule 91 DSM Rider Level to Recover Revenue Requirement associated with Capitalizing DSM Expenditures and Recovery of Fixed Costs**
**2008 - 2017**
**(000s of $)**

| | Est. Base Retail Rev.(1) | Est. DSM Capital Expend.(2) | DSM Rev. Require.(3) | Capital Rev. Require.(4) | Est. Fixed Costs(5) | DSM Rev. Less Expend. | DSM Deficiency Balance(6) | DSM Rider %(7) | Inc cost inc due to reg/acctg changes |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | (d)+(e)+(f) | | | (c)-(d)-(e) | | (c)/(a) | (d+e)-(b) |
| 2007 | $320,000 | | | | | | $3,800 | | |
| 2008 | $336,000 | $7,000 | $4,500 | $1,191 | $539 | $2,770 | $1,030 | **1.4%** | ($5,270) |
| 2009 | $352,800 | $7,350 | $4,500 | $2,753 | $566 | $1,181 | ($151) | **1.4%** | ($4,031) |
| 2010 | $370,440 | $7,718 | $4,500 | $4,319 | $594 | ($151) | $262 | **1.4%** | ($2,804) |
| 2011 | $388,962 | $8,103 | $6,775 | $5,889 | $624 | | $0 | 1.7% | ($1,590) |
| 2012 | $408,410 | $8,509 | $8,120 | $7,465 | $655 | | | 2.0% | ($388) |
| 2013 | $428,831 | $8,934 | $9,737 | $9,049 | $688 | | | 2.3% | $803 |
| 2014 | $450,272 | $9,381 | $11,365 | $10,643 | $722 | | | 2.5% | $1,985 |
| 2015 | $472,786 | $9,850 | $13,006 | $12,248 | $758 | | | 2.8% | $3,157 |
| 2016 | $496,425 | $10,342 | $14,661 | $13,865 | $796 | | | 3.0% | $4,319 |
| 2017 | $521,246 | $10,859 | $16,332 | $15,496 | $836 | | | 3.1% | $5,473 |

(1) Estimated WA 2007 retail revenue escalated at 5% per year.
(2) Estimated WA Electric DSM expenditures escalated at 5% per year.
(3) Annual DSM Revenue needed to recover capital revenue requirement, fixed cost and deficiency (through 2010)
(4) Annual revenue requirement for recovery of capitalized DSM expenditures using ten-year amortization
(5) Estimated (lost) fixed costs for 2008 escalated at 5% per year
(6) Est. deficiency balance of $3.8 million at 12/31/07 - excess DSM Rev. in '08 & '09 used to pay down balance
(7) No change to present rider until 2011

PC DR-38 - Attachment A
**Avista Utilities**
**Washington - Gas**
**Estimated Schedule 191 DSM Rider Level to Recover Revenue Requirement associated with Capitalizing DSM Expenditures**
**2008 - 2017**
**(000s of $)**

| | Est. Base Retail Rev.(1) (a) | Est. DSM Capital Expend.(2) (b) | DSM Rev. Require.(3) (c) (d)+(f) | Capital Rev. Require.(4) (d) | DSM Rev. Less Expend. (e) | DSM Deficiency Balance(5) (f) | DSM Rider %(6) (g) (c)/(a) | Inc cost inc due to reg/acctg changes (h) (d)+(e)-(b) |
|---|---|---|---|---|---|---|---|---|
| 2007 | $198,000 | | | | | $590 | 1.6% | $0 |
| 2008 | $207,900 | $2,300 | $981 | $391 | $590 | $0 | 0.5% | ($1,319) |
| 2009 | $218,295 | $2,415 | $905 | $905 | $0 | $0 | 0.4% | ($1,510) |
| 2010 | $229,210 | $2,536 | $1,419 | $1,419 | | | 0.6% | ($1,117) |
| 2011 | $240,670 | $2,663 | $1,935 | $1,935 | | | 0.8% | ($728) |
| 2012 | $252,704 | $2,796 | $2,453 | $2,453 | | | 1.0% | ($343) |
| 2013 | $265,339 | $2,935 | $2,973 | $2,973 | | | 1.1% | $38 |
| 2014 | $278,606 | $3,082 | $3,497 | $3,497 | | | 1.3% | $415 |
| 2015 | $292,536 | $3,236 | $4,024 | $4,024 | | | 1.4% | $788 |
| 2016 | $307,163 | $3,398 | $4,556 | $4,556 | | | 1.5% | $1,158 |
| 2017 | $322,521 | $3,568 | $5,091 | $5,091 | | | 1.6% | $1,523 |

(1) Estimated WA 2007 retail revenue escalated at 5% per year
(2) Estimated WA Gas DSM expenditures escalated at 5% per year
(3) Annual DSM Rev. needed to recover capital revenue requirement and deficiency (through 2008)
(4) Annual rev. require. for recovery of capitalized DSM expenditures using ten-year amortization
(5) Est. deficiency balance of $590,000 at 12/31/07 - DSM Rider of 0.5% in '08 would recover capital rev. require. of $391,000 and deficiency balance
(6) Present DSM Rider of 1.6% ($3.1 million/year) could be reduced to 0.5% in 2008

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | | |
|---|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/13/2007 | |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Bruce Folsom | |
| REQUESTER: | Public Counsel | RESPONDER: | Lori Hermanson | (509) 495-4658 |
| TYPE: | Data Request | RESPONDER: | Jon Powell | (509) 495-4047 |
| REQUEST NO.: | PC - 36 | DEPT: | Energy Solutions | |

**REQUEST:**
Please provide the following information regarding Avista's current and anticipated spending on efficiency:

a. Please provide the actual amount in 2006 on electricity and natural gas efficiency programs respectively.
b. Please report the actual amount spent on electricity and natural gas efficiency programs respectively in 2006 as a percentage of actual electric and natural gas revenues in that year.
c. Please indicate the amount that Avista expects to spend on electricity and natural gas efficiency programs in 2008.
d. Please describe the process that Avista will use to determine how much to budget for efficiency in 2008 in order to place efficiency on an equal footing with new supply as a new resource.
e. Please identify the anticipated percentage of the 2008 efficiency budget will be allocated to the following components - program design, administration, incentives, marketing, implementation, and evaluation.

**RESPONSE:**
a. The actual amount spent in 2006 on electric efficiency was $8.2 million and for natural gas efficiency was $2.8 million.

b. The $8.2 million spent on electric efficiency was 15% more than collected in DSM electric revenues and 1.5% of actual total electric revenues. The $2.8 million spent on natural gas efficiency was 83% more than was actually collected in DSM natural gas revenues and 0.7% of actual total natural gas revenues.

c. Our expected 2008 budget is $7.0 million for Washington electric programs and $2.3 million for Washington gas programs. These early projections were based off a 2006 estimate for 2008, and may be modified during our 2008 business planning, which is anticipated to occur in the late summer and fall of 2007.

d. Avista's core objective is to acquire cost-effective efficiency resources that are available through utility intervention. This process includes the high-level identification of acquirable resource potential through the Integrated Resource Plan

(IRP) process and basic avoided cost projections. This corporate effort then becomes a starting point for a more detailed demand-side management (DSM) business planning process. The business planning process produces avoided cost levels that include factors to make them more applicable for the evaluation of DSM efforts, plans for targeted measures and markets, infrastructure requirements, program outreach plans, participation and leveraging of regional and national efficiency programs and budget requirements. These plans are living documents that are frequently modified over the course of the year based upon further evaluation and revised expectations.

The overall process does strive to create a level playing field for efficiency and generation resource alternatives that includes consideration of factors such as risk, emissions, transmission and distribution losses, capacity valuation, time-of-use and other factors.

e. Avista utilizes three categorizations of overall efficiency program utility cost. These categorizations are:
   - incentives (composed of direct financial incentives received by the customer),
   - utility labor expense (the fully load cost of labor expended in demand-side management operations) and
   - non-labor utility expense (all non-labor, non-incentive expenses incurred in demand-side management operations)

The table below is our current projection of the proportions that we anticipate for each of these categories in 2008.

| | WA electric | WA gas |
|---|---|---|
| Incentives | 79% | 83% |
| Labor utility expense | 13% | 11% |
| Non-labor utility expense | 8% | 6% |
| Total | 100% | 100% |

These projections have been made in advance of the detailed 2008 business planning process that will occur in the late summer and fall of 2007.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/12/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Heather Cummins |
| TYPE: | Data Request | DEPT: | Distribution Engineering |
| REQUEST NO.: | PC - 187 | TELEPHONE: | (509) 495-4430 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 8 and Response to PC 55.

Ms. Cummins indicates that the preliminary estimate of the total cost of installing an AMR system for gas and electric meters in Washington may be as much as $71.4 million. She also indicates that no incremental costs are required to modify its billing system to accept monthly information from certain of these new meters (response to PC 55 c and f) but there will be incremental costs required to modify its billing system to accept monthly information from the new electric meters to be installed under phase II (response to PC 55 i and l). Please provide the following information regarding the economic justification for this program:

a. The total capital project budget for the installation of AMR, including but not limited to associated upgrades of data processing and billing systems, and any other costs associated with AMR deployment that Avista management has approved for Washington. Please provide the major components of this budget by cost category and by year.

b. The economic justification upon which Avista management based their decision to approve this capital project budget.

c. Confirmation that Avista understands it will have to demonstrate that this investment is prudent, used and useful in a future general rate case in order to recover any, or all, of the revenue requirements associated with this investment in its rates?

d. To the extent not provided in response to the above, please provide Avista's projections of total costs associated with the deployment of advanced metering in Washington. Please provide the major components of this cost projection by cost category and by year (e.g., cost categories may include, but are not limited to: meter costs, installation costs, billing system upgrades, data processing and analysis).

e. Any and all studies prepared by or for Avista, or reviewed by Avista, regarding demand response programs, including but not limited to time-of-use programs, critical peak pricing programs, or direct load control programs.

f. Any and all studies prepared by or for Avista, or reviewed by Avista, regarding the use of "smart" or advanced meters in connection with demand response programs.

**RESPONSE:**

a. The incremental costs of modifications to Avista's existing billing systems to incorporate monthly billing for the Phase II AMR meters has not been specifically included in the estimates. See attached spreadsheet (Attachment A) for additional data.

b. The Washington AMR project is in Avista's plan, but is subject to final approval by the annual Avista capital budgeting process. The initial AMR project was justified on the basis that it was relatively rate payer neutral in the long run. The incremental cost of the Phase II system for Washington will need to be analyzed as the scope is determined.

c. Yes, the Company understands it will have to demonstrate that the investment in AMR is prudent, used and useful in a future general rate case in order to recover any, or all, of the revenue requirements associated with our investment in rates.

d. Please refer to the attached spreadsheet referenced in a. above.

e. Over time the Company stays current with literature on demand response programs but does not retain in its files all that has been reviewed. Attached are those documents that have been reviewed and are in our files. Due to the voluminous nature of these documents, the attachments are only being provided in electronic format. The Company will produce paper hard copies upon specific request.

Attachment D – faruqui proposal
Attachment E – EEI Plexus
Attachment F – EEI NERA
Attachment G – NARUC FERC
Attachment H – FERC_Act
Attachment I – WG2_DR_Final_Report
Attachment J – Valuation of Demand Response Vol 1 01-2006
Attachment K – Valuation of Demand Response Vol 2 01-2006
Attachment L – Lawrence Berkeley_2007_May_Demand Response_Report
Attachment M – BestPractice_DRPrograms
Attachment N – Residential_Load_Control_2-20-0
Attachment O – demand-response
Attachment P – LMADRT_060506

Avista also reviewed information from the following website links:

http://www.aesp.org/associations/5980/files/Goldman_Chuck_Final.pdf

www.ferc.gov/legal/staff-reports/demand-response.pdf

http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/programs_and_incentives/progs.pdf

Please also see Avista's CONFIDENTIAL response PC-187 C for the following four CONFIDENTIAL attachments:

Confidential Attachment B
Confidential Attachment C
Confidential Attachment Q
Confidential Attachment R

Please note that Avista's **CONFIDENTIAL** response to PC - 187 C is protected from disclosure per Protective Order (Order 03 issued May 30, 2007 under Docket Number UE-070804, UG-070805, and UE070311) and by WAC 480-07-160.

Due to the voluminous nature of these documents, the attachments are only being provided in electronic format. The Company will produce paper hard copies upon specific request.

f. Over time the Company stays current with literature on "smart" or advanced meters but does not retain in its files all that has been reviewed.

Avista continues to review and monitor information regarding "smart" or advanced metering from many resources. The following website links are of particular interest:

www.utilipoint.com

http://www.sce.com/PowerandEnvironment/ami/

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 09/06/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Linda Gervais |
| TYPE: | Data Request | DEPT: | State and Federal Regulation |
| REQUEST NO.: | PC - 156 | TELEPHONE: | (509) 495-4975 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 2 and Response to PC 32 b.

a. Please provide the requests that Avista filed in Idaho Cases AVU-E-O4-1 and AVU-G-O4-1.

b. Please provide Order 29602 from that proceeding.

**RESPONSE:**

Please see the attached Idaho request AVU-E-04-1, AVU-G-04-1 (PC_DR_156-Attachment A & B) and Idaho Order 29602 (PC_DR_156-Attachment C & D).

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**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION | ) | CASE NO. AVU-E-04-01 |
| OF AVISTA CORPORATION FOR THE | ) | CASE NO. AVU-G-04-01 |
| AUTHORITY TO INCREASE ITS RATES | ) | |
| AND CHARGES FOR ELECTRIC AND | ) | |
| NATURAL GAS SERVICE TO ELECTRIC AND | ) | DIRECT TESTIMONY |
| NATURAL GAS CUSTOMERS IN THE STATE | ) | OF |
| OF IDAHO | ) | DAVID D. HOLMES |
| | ) | |

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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

A. My name is David D. Holmes and I am employed as the Manager of Distribution Engineering for Avista Utilities, at 1411 East Mission Avenue, Spokane, Washington.

**Q. Would you describe your educational background and professional experience?**

A. I am a 1977 graduate of Montana State University with a degree in Electrical Engineering. I originally joined the Company in 1977 and spent eighteen years in various engineering and management positions including five years managing the Company's electric and natural gas metering departments. In 1995, I left the utility to develop advanced metering systems for Avista Advantage and then joined Avista Labs to direct their Application Engineering staff. In early 2003, I rejoined Avista Utilities to supervise the Distribution Engineering staff. I am a Professional Electrical Engineer in the States of Idaho and Washington.

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

A. My testimony will describe Avista's proposal for implementation of Advanced Meter Reading (AMR) for Avista's customers in the State of Idaho.

**Q. Please summarize the Company's request in this case regarding Advanced Meter Reading, or AMR.**

A. The Company proposes to install AMR devices on all Idaho electric and natural gas meters over a four-year period commencing January 2005. The Company is not proposing a change in rates in this filing related to the implementation of AMR. Mr. Falkner explains the Company's proposal for the future ratemaking treatment of the costs associated with this program.

**Q. Has Avista been following the Commission's recent examination of AMR?**

A. Yes. The Company has been actively monitoring Case No. IPC-E-02-12. While Avista has not submitted written comments in that proceeding, Company representatives attended the Commission's June 5, 2003 technical workshop and participated in the December 2, 2003 workshop via a conference bridge.

**Q. Please summarize the Company's perspective on AMR.**

A. Avista has been following the development of AMR over the past decade, and periodically assessing possible AMR implementation in areas where it is demonstrably cost-effective. The Company has installed a small number of AMR devices on some meter reading routes and customer locations that involve extensive driving, lack of access or have represented a hazard for our personnel.

The Company has also monitored development of AMR technology with attention to costs and with an eye to the future. Regarding costs, we have noted that AMR technology has been improving and its costs are generally decreasing. Our plan is to select and install systems that are compatible with existing systems, long-lived, and suitable for later expansion.

The cost of manual meter reading continues to increase. Meter reading expenses in Idaho have increased an average of 4.8% per year since 1995, as shown in Exhibit No. 13. Page 1 depicts historical meter reading expenses in Idaho, Washington and Oregon. We believe that the expected continual increases in meter reading expenses and a decline in equipment pricing indicate that now is the time to commit to a broader implementation of AMR technology.

**Q. What technology, or type of AMR devices, is the Company proposing to install?**

A. The Company will utilize a combination of AMR technologies in its Idaho service territory. We intend to install radio-based technology in areas with higher meter densities, and a power line carrier (PLC) based technology in areas with lower densities. We will continue to use telephone-based technologies for selected industrial accounts. A number of factors will determine where each technology is utilized including geography, distribution configuration, installation costs and the presence of natural gas. All electric technologies will have the capability to provide hourly or more frequent interval data. Meters utilizing a radio-based technology will initially be read monthly through a mobile device. They will not require modification when a fixed radio communication network is added to collect data in the latter phases of the project.

**Q. Will the proposed AMR technology provide such functions as automated meter reading, theft detection, accuracy improvement, improved outage monitoring, flexible billing schedules, account aggregation, and improved customer service?**

A. Yes. The equipment we propose to install will provide interval metering data, as well as indications of tampering and information on outage conditions. Data collected from this equipment will enable us to provide flexible billing schedules for our customers. This equipment is not intended to provide aggregated demands for tariff calculations, but it will enhance our ability to provide consolidated billing statements for customers with multiple accounts.

This system will greatly reduce estimated reads, reduce the volume of phone calls associated with estimated reads and the need for investigations related to such calls. Customer billings will tend to be more accurate because estimates and misreads will be reduced. The actual metering accuracy will not be affected by this automated system and will continue to be monitored through our periodic sampling program.

**Q. Will this system provide the capability for future Time-of-Use or critical peak pricing?**

A. Yes. This technology will allow the remote capture of electric interval meter readings in intervals of one hour or less. The significance of capturing interval readings is that it provides the foundation for later adoption of retail energy pricing that may vary by hour of the day or day of the week. This type of pricing can ultimately be used to provide economic incentives to customers to curtail usage during critical energy periods.

Although this project does not include the necessary modifications to our billing system to implement a time of use or critical peak rate structure, this equipment will provide all the field data necessary to support this type of system in the future.

**Q. What other AMR systems did the Company review prior to selecting the technology it did?**

A. Avista has evaluated several advanced metering systems. Avista has installed over 74,000 radio and 350 PLC based AMR devices throughout Washington, Oregon and California including 1,700 within the State of Idaho. Our supplier for radio-based equipment has been Itron, based in Spokane, Washington. We have utilized Hunt Technologies for PLC based technology and are currently reviewing Distribution Control System's Incorporated TWACS PLC technologies. We will continue to review vendor technologies to ensure program requirements are met and future technology migration and service is available.

**Q. How will you determine the AMR plan for roll out and the most cost-effective area to begin implementation?**

A. An efficient deployment of AMR systems is based on the specific attributes of each geographic area. Our intent is to begin AMR installations in areas that will free up the most labor, which in turn will be used to accelerate additional installations. These areas tend to be more rural in nature, however, the same attributes that make these meters more costly to read, reflect a generally higher AMR retrofit cost. Efficient utilization of PLC technology is usually accomplished with the conversion of customers served by the same substation. The efficient deployment of radio-based systems tend to be organized by the specific terrain and geographic densities. Specific system design, vendor evaluation and selection will take place in 2004.

**Q. What is the projected cost to install this system in Idaho?**

A. We estimate the cost of installing this system in Idaho will be approximately $16,300,000. We propose that this system be installed over a four year time period beginning in 2005, with approximately equal expenditures in each year as shown in Exhibit 13. Page 2 is a summary of costs in 2003 dollars associated with the proposed AMR installation. It is important to note that these are initial estimates. The selection of appropriate technologies for each location, vendor, evaluation, and selection, as well as a refinement of cost estimates will take place during 2004.

**Q. What are your anticipated hard dollar savings?**

A. Avista believes that installing a fully networked AMR system on all of Idaho's meters will represent an annual operations savings of approximately $994,000. The majority of these savings (92%) is achieved through a 91% reduction in meter reading labor and associated expenses. Other savings are represented by efficiencies in customer billing, service, reduced energy diversion and reduced meter maintenance, as shown in Exhibit 13. Page 3 represents estimated savings associated with the installation on Avista's system.

**Q. Will the hard dollar savings offset all of the costs, or will this project cause an increase in overall net costs?**

A. Our current estimates indicate that the costs of this project, as compared to the costs of continuing with the technology and operations that are currently in place, will result in additional annual electric costs of $188,700. This additional cost represents approximately 0.13% of the Company's $146,000,000 of annual electric revenues.

With regard to natural gas, we estimate that the costs of this project, as compared to the costs of continuing with the technology and operations that are currently in place, will result in a decrease in costs of $63,000 per year. These cost savings represent approximately 0.12% of the Company's $51,000,000 annual natural gas revenues. These values are based on an analysis of costs and benefits over a fifteen-year period. The costs/benefit analyses show higher net costs in the early years, which decline over time. This is shown in Exhibit 13.

Pages 4, 5, and 6 depict estimated annual costs, savings and net annual revenue requirements for an AMR system, compared to not installing an AMR system over a fifteen-year period.

We believe the relatively small levelized costs on the electric side are justified by other benefits associated with this proposed system.

**Q. Please describe these additional benefits to the Company and its customers.**

A. There are a number of benefits to AMR that clearly exist, but for which dollar values are difficult to quantify. For example, information obtained through a networked AMR system will be of value in determining specifications for distribution equipment used to serve our customers. Interval data provided by the system can be utilized for customer load research and rate development programs. A networked AMR system can provide information to help manage operations during outages and may prevent extended customer outages where a traditional outage report may have not been made. There may be opportunities to provide meter-reading services for other utilities. Furthermore, the addition of software in the future, not provided in the scope of this project, would allow customers on-line access to hourly load profile data, which would allow them the opportunity to better manage their electricity consumption.

**Q. Does this conclude your prefiled direct testimony?**

A. Yes.

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**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION | ) | CASE NO. AVU-E-04-01 |
| OF AVISTA CORPORATION FOR THE | ) | CASE NO. AVU-G-04-01 |
| AUTHORITY TO INCREASE ITS RATES | ) | |
| AND CHARGES FOR ELECTRIC AND | ) | |
| NATURAL GAS SERVICE TO ELECTRIC AND | ) | EXHIBIT NO. 13 |
| NATURAL GAS CUSTOMERS IN THE STATE | ) | |
| OF IDAHO | ) | DAVID D. HOLMES |
| | ) | |

FOR AVISTA CORPORATION

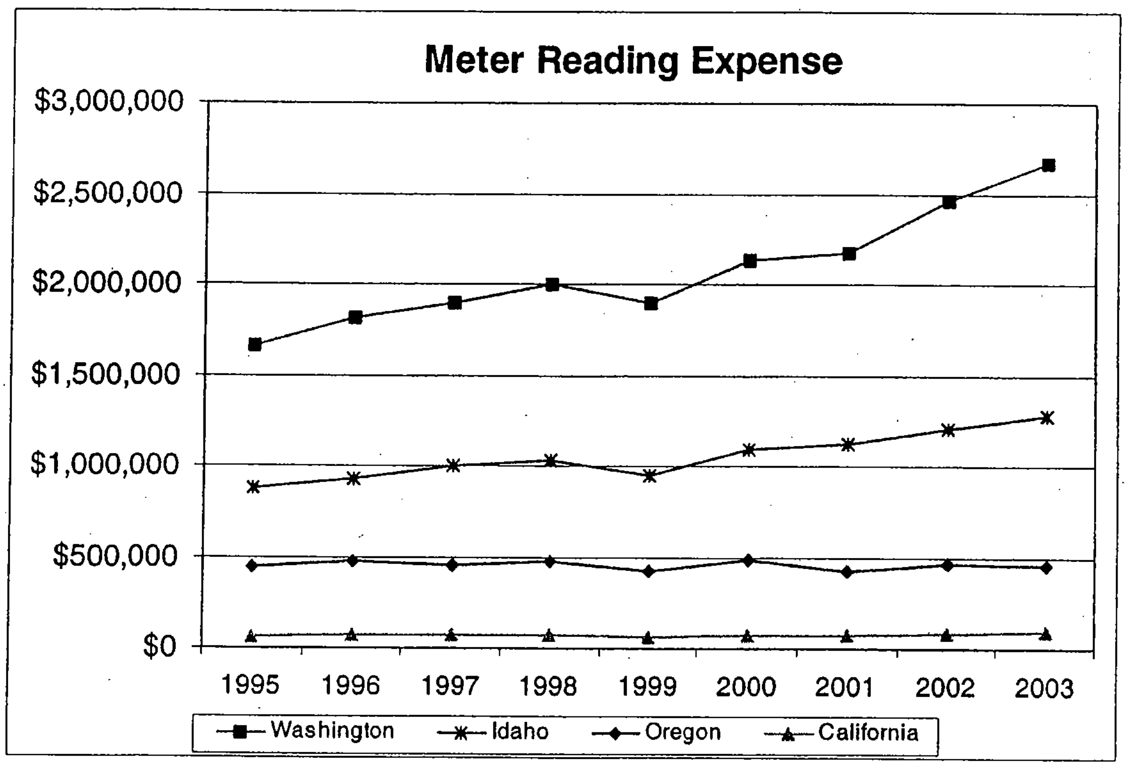
(ELECTRIC AND NATURAL GAS)

## Historical Meter Reading (x902.xx) Costs

| | Washington | | | Idaho | | | Oregon | | | California | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost | Cust | $/mtr | Cost | Cust | $/mtr | Cost | Cust | $/mtr | Cost | Cust | $/mtr |
| 1995 | $1,661,190 | 293,138 | $5.67 | $879,447 | 132,368 | $6.64 | $447,346 | 61,513 | $7.27 | $66,866 | 17,233 | $3.88 |
| 1996 | $1,819,206 | 300,268 | $6.06 | $927,554 | 138,495 | $6.70 | $476,603 | 65,290 | $7.30 | $69,291 | 17,582 | $3.94 |
| 1997 | $1,894,833 | 307,682 | $6.16 | $1,000,371 | 143,919 | $6.95 | $451,448 | 68,623 | $6.58 | $73,587 | 17,742 | $4.15 |
| 1998 | $2,001,076 | 315,675 | $6.34 | $1,036,070 | 150,009 | $6.91 | $471,254 | 72,850 | $6.47 | $76,843 | 18,107 | $4.24 |
| 1999 | $1,898,692 | 322,862 | $5.88 | $946,753 | 154,992 | $6.11 | $426,819 | 74,878 | $5.70 | $59,188 | 18,002 | $3.29 |
| 2000 | $2,132,285 | 328,163 | $6.50 | $1,093,684 | 159,269 | $6.87 | $481,281 | 77,689 | $6.19 | $72,852 | 17,941 | $4.06 |
| 2001 | $2,175,057 | 346,535 | $6.28 | $1,120,487 | 162,436 | $6.90 | $424,039 | 84,981 | $4.99 | $74,243 | 18,571 | $4.00 |
| 2002 | $2,459,379 | 348,000 | $7.07 | $1,207,072 | 165,304 | $7.30 | $467,047 | 86,000 | $5.43 | $80,761 | 18,600 | $4.34 |
| 2003 | $2,668,689 | 350,571 | $7.61 | $1,283,042 | 172,745 | $7.43 | $449,604 | 89,587 | $5.02 | $93,515 | 18,762 | $4.98 |

4.8%

Average annual growth



**Estimated AMR Installation Cost (nominal 2003 dollars)**

## Estimated Unit Costs (2003 dollars)

| Type | Total | Prior | To Convert | Unit Cost | Meter Cost |
|---|---|---|---|---|---|
| Electric Non Demand | 79,962 | 920 | 79,042 | $62.25 | $4,920,394 |
| Electric Demand | 3,332 | 0 | 3,332 | $263.25 | $877,088 |
| PLC Non Demand | 26,654 | 169 | 26,485 | $138.25 | $3,661,573 |
| PLC Demand | 1,111 | 0 | 1,111 | $263.25 | $292,363 |
| Total Electric | 111,059 | | 109,970 | $88.67 | $9,751,419 |
| Total Gas | 61,686 | 601 | 61,085 | $67.75 | $4,138,509 |
| Total Electric & Gas | 172,745 | 1,690 | 171,055 | $81.20 | **$13,889,928** |

Meter per point **$81**

| | |
|---|---|
| Network meters | 144,980 |
| Collector cost | $2,320 |
| Cust/Collector | 140 |
| Communication/mo | $20 |

| Gas | Electric | Network |
|---|---|---|
| $857,892 | $1,544,638 | **$2,402,530** |

Network per point **$17**

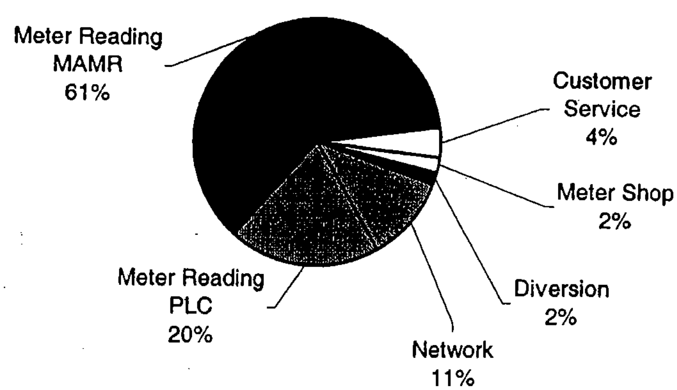
## Estimated Project Costs (2003 dollars)

| Year | Units Gas | Units Electric | Cost Gas | Cost Electric | Network Gas | Network Electric | Total Gas | Total Electric | Project Total |
|---|---|---|---|---|---|---|---|---|---|
| 2004 | 601 | 1,089 | | | | | | | |
| 2005 | 18,326 | 32,991 | $1,241,553 | $2,925,426 | | | $1,241,553 | $2,925,426 | $4,166,978 |
| 2006 | 18,326 | 32,991 | $1,241,553 | $2,925,426 | | | $1,241,553 | $2,925,426 | $4,166,978 |
| 2007 | 12,217 | 21,994 | $827,702 | $1,950,284 | $514,756 | $926,762 | $1,342,457 | $2,877,046 | $4,219,503 |
| 2008 | 12,217 | 21,994 | $827,702 | $1,950,284 | $343,170 | $617,841 | $1,170,872 | $2,568,125 | $3,738,997 |
| 2009 | 0 | 0 | $0 | $0 | | | $0 | $0 | $0 |
| 2010 | 0 | 0 | $0 | $0 | | | $0 | $0 | $0 |
| 2011 | 0 | 0 | $0 | $0 | | | $0 | $0 | $0 |
| 2012 | 0 | 0 | $0 | $0 | | | $0 | $0 | $0 |
| | 61,686 | 111,059 | $4,138,509 | $9,751,419 | $857,926 | $1,544,604 | $4,996,435 | $11,296,023 | **$16,292,458** |

## AMR Estimated Savings (nominal 2003 dollars)

| Annual Savings | | Savings |
|---|---|---|
| Meter Reading PLC | - Reduction in Meter reading staff | $195,908 |
| Meter Reading MAMR* | - Reduction in Meter reading staff | $613,789 |
| Customer Service | - Call Center, Rebills | $37,000 |
| Meter Shop | - Meter refurbishment reduction & testing | $20,000 |
| Diversion | - Tamper reduction | $18,000 |
| **Annual savings from MAMR & PLC system** | | **$884,697** |
| Additional Meter Reading Savings from Network | | $358,044 |
| Network operation (communication to collectors) | | -$248,538 |
| Network | - Additional net savings from network | **$109,506** |
| **Annual AMR savings with fixed network (full implementation)** | | **$994,203** |

**AMR Savings**




* Mobile Advanced Meter Reading (MAMR)

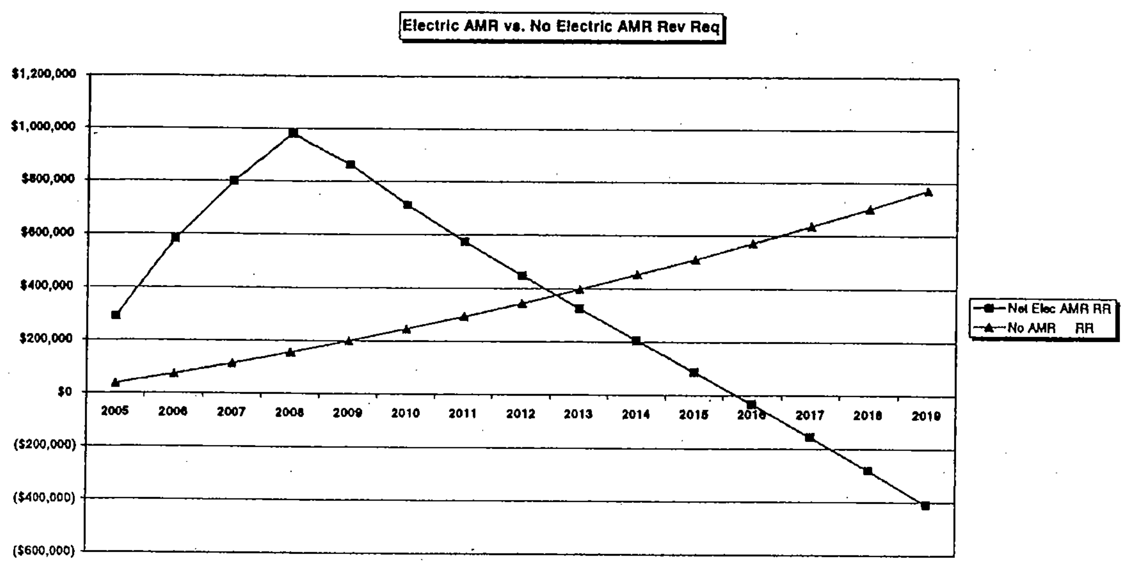
# AMR Estimated Rate Impact

| Idaho | | AMR Levelized Revenue Requirement | | No AMR Levelized Revenue Requirement | | Incremental Levelized Revenue Requirement |
|---|---|---|---|---|---|---|
| **2002 Pro forma Idaho Electric** | | | | | | |
| Capital Investment | $ | 11,296,023 | | | | |
| Revenue | $ | 146,000,000 | $ | 146,000,000 | $ | 146,000,000 |
| AMR $ Impact | $ | 486,567 | | $297,864 | $ | 188,703 |
| AMR % | | **0.33%** | | **0.20%** | | **0.13%** |
| **2002 Pro forma Idaho Gas** | | | | | | |
| Capital Investment | $ | 4,996,435 | | | | |
| Revenue | $ | 51,000,000 | $ | 51,000,000 | $ | 51,000,000 |
| AMR $ Impact | $ | 105,077 | $ | 168,136 | $ | (63,059) |
| AMR % | | **0.21%** | | **0.33%** | | **-0.12%** |

**Notes:**
1. Assumes 15yr book life of AMR

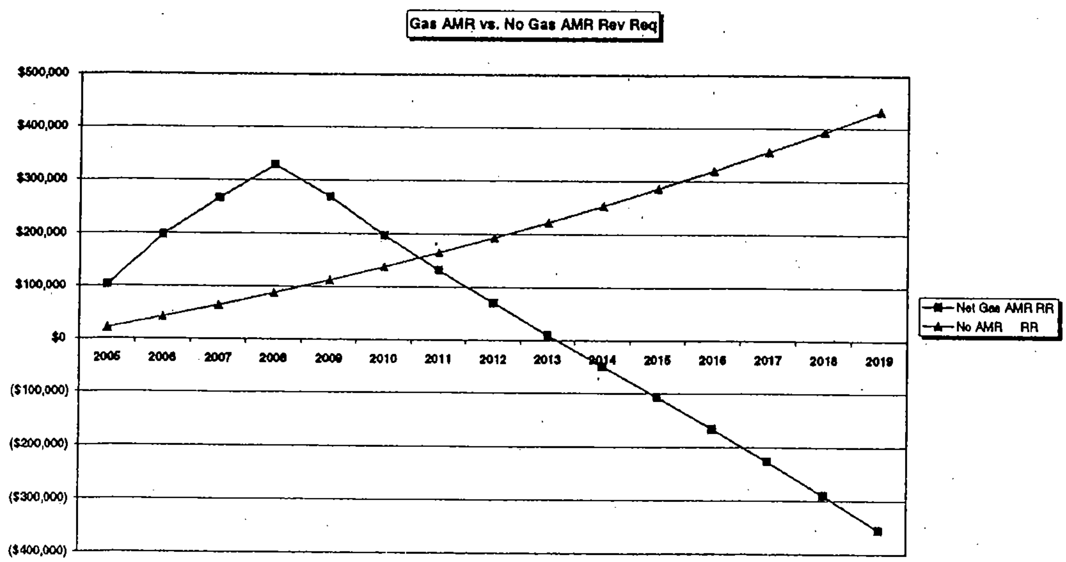
**Electric AMR Costs and Savings by year versus No AMR Costs**

| Year | Elec AMR Costs | Elec AMR Savings | Net Elec AMR RR | No AMR RR |
|---|---|---|---|---|
| 2005 | $449,613 | $160,055 | $289,558 | $36,260 |
| 2006 | $942,644 | $362,215 | $580,430 | $74,260 |
| 2007 | $1,387,170 | $587,921 | $799,250 | $114,084 |
| 2008 | $1,754,795 | $774,288 | $980,506 | $155,820 |
| 2009 | $1,699,746 | $836,899 | $862,848 | $199,559 |
| 2010 | $1,587,180 | $877,070 | $710,111 | $245,398 |
| 2011 | $1,493,217 | $919,169 | $574,048 | $293,437 |
| 2012 | $1,409,992 | $963,289 | $446,703 | $343,782 |
| 2013 | $1,333,395 | $1,009,527 | $323,868 | $396,543 |
| 2014 | $1,263,143 | $1,057,985 | $205,159 | $451,837 |
| 2015 | $1,195,945 | $1,108,768 | $87,177 | $509,785 |
| 2016 | $1,128,746 | $1,161,989 | ($33,243) | $570,514 |
| 2017 | $1,061,547 | $1,217,764 | ($156,217) | $634,158 |
| 2018 | $994,349 | $1,276,217 | ($281,868) | $700,858 |
| 2019 | $927,150 | $1,337,475 | ($410,325) | $770,759 |



**Gas AMR Costs and Savings by year versus No AMR Costs**

| Year | Gas AMR Costs | Gas AMR Savings | Net Gas AMR RR | No AMR RR |
|---|---|---|---|---|
| 2005 | $188,284 | $85,843 | $102,441 | $20,330 |
| 2006 | $395,904 | $197,990 | $197,914 | $41,635 |
| 2007 | $601,763 | $335,587 | $266,176 | $63,963 |
| 2008 | $771,236 | $442,458 | $328,778 | $87,363 |
| 2009 | $749,071 | $480,274 | $268,797 | $111,886 |
| 2010 | $699,986 | $503,328 | $196,658 | $137,587 |
| 2011 | $659,137 | $527,487 | $131,649 | $164,521 |
| 2012 | $622,859 | $552,807 | $70,053 | $192,747 |
| 2013 | $589,461 | $579,341 | $10,120 | $222,329 |
| 2014 | $558,926 | $607,150 | ($48,224) | $253,330 |
| 2015 | $529,750 | $636,293 | ($106,543) | $285,820 |
| 2016 | $500,575 | $666,835 | ($166,260) | $319,869 |
| 2017 | $471,399 | $698,843 | ($227,444) | $355,552 |
| 2018 | $442,224 | $732,388 | ($290,164) | $392,948 |
| 2019 | $413,048 | $767,542 | ($354,494) | $432,140 |



# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 07/09/2007 |
| CASE NO: | UE-070804/UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Heather Cummins |
| TYPE: | Data Request | DEPT: | Distribution Engineering |
| REQUEST NO.: | PC -34 | TELEPHONE: | (509) 495-4430 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 8, lines 10 to 12.

Please provide the following information regarding Avista's economic justification for investment in AMR:

a. Does Avista expect to justify rate recovery of these investments solely on demonstrated, or projected, savings in its operating costs? Please explain why, or why not.

b. Does Avista expect to justify rate recovery of these investments in whole or in part on the potential for customers to reduce their costs if they have the capability to respond to time-of-use critical peak pricing. If so, please provide all research and analyses prepared by, or for, Avista to support that expectation.

**RESPONSE:**

a. The estimated operational cost savings are expected to justify a portion of the investment in AMR. Other cost savings are expected through improved supply resource management that the selected AMR system would provide a foundation for. The AMR system enables more granular data around usage patterns for the company and customer to leverage which could help manage resource costs more effectively.

b. Avista has provided two cost estimates for its urban areas. The low estimate assumes one-way radio based communication, while the high estimate assumes two-way radio based communication. The two-way solution would allow for real-time price signal communication to customers, providing the foundation for time-of-use critical peak pricing. If the two-way radio based communication method is chosen, the higher investment could be partially justified by this functionality. However, before decisions are made, more research needs to be done concerning the value of time-of-use critical peak pricing, the cost of supporting billing system modifications required to support this type of pricing, and other customer communication methods available to deliver this real-time information to customers.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/27/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Heather Cummins |
| TYPE: | Data Request | DEPT: | Distribution Engineering |
| REQUEST NO.: | PC - 56 | TELEPHONE: | (509) 495-4430 |

**REQUEST:**
Re: Avista Response to Public Counsel Data Request No. 34.
The response to PC-34 a states that "...other cost savings are expected through improved supply resource management". Please provide examples of the types of improvements in supply resource management that Avista is expecting, and how it expects those savings to produce savings in supply costs.

**RESPONSE:**
With the AMR foundation in place, some possible improvement in supply resource management could be experienced through shifting of supply needs and reducing capacity needs with the implementation of Time of Use Pricing or Critical Peak Pricing, if those rate structures are implemented in the future.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 9/11/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Bruce Folsom |
| REQUESTER: | Public Counsel | RESPONDER: | Lori Hermanson |
| TYPE: | Data Request | DEPT: | Energy Solutions |
| REQUEST NO.: | PC - 161 | TELEPHONE: | (509) 495-4658 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 8, lines 10 to 12.

Please provide the following information regarding Avista's economic analyses of prospective investments in AMR:

a. Avista's comments dated August 11, 2006 in Docket UE-060649 indicate, on page 2, that time-of-use (TOU) meters could be cost-effective for some customer classes, e.g. large industrial, but are not likely to be cost-effective for all customer classes. Please indicate if Avista has designed its deployment of AMR to evaluate the cost-effectiveness by customer class? If Avista is not evaluating the cost-effectiveness by customer class please explain why not.

b. Avista's comments dated August 11, 2006 in Docket UE-060649 refer, on page 3, to a "high-level study" of the cost-effectiveness of TOU meters. Please provide a copy of this "high level study," as well as any study conducted by or on behalf of Avista regarding the cost-effectiveness of advanced metering technology (please include any memos or workpapers).

c. Please describe Avista's plans for updating the "high level study," referred to above in part (b), in its analysis of cost-effectiveness in connection with its evaluation of AMR technology in Washington. If Avista has already updated the study please provide a copy. If Avista is not planning to update this analysis please explain why not.

d. Avista's comments dated August 11, 2006 in Docket UE-060649 present on page 5, eight factors that Avista recommended the Commission consider in determining whether time-based rates and meters are cost-effective. Does Avista continue to recommend consideration of these eight factors? If not, please explain why not.

**RESPONSE:**

a. The initial and primary (though not sole) intent of the AMR effort was to cost-effectively manage meter reading costs and address other operational issues (e.g. dog bites, intrusion upon customers, reduce estimated meter reads etc). The application of this tool for TOU rate design has been incorporated into the effort because we want to preserve and prepare for this contingency in the future. Avista has and continues to evaluate the potential impact of TOU rate design, and this consideration is segmented by market classes (to include segmentation by rate classes).

b. The referenced statement on page 3 of Avista's comments is as follows: "A high-level study recently performed by Avista shows the value of Avista's on-peak/off-peak differential, combined with avoided capacity charges, to be under 1.5 cents per kilowatt hour." This high-level study was the then-preliminary results of on-peak/off-peak analyses derived from the Company's electric integrated resource planning (IRP) process. The attached spreadsheet shows this documentation. While the spreadsheet is dated after the referenced comments were submitted, it documents the internal discussions regarding the cost analysis of on-peak/off-peak differentials.

Please see previously submitted PC-156 response. The Company continues to analyze and monitor AMR technology.

c. Avista is finalizing cost-effective analyses for load management programs from an avoided cost perspective. This will be provided upon completion as a supplemental response to this request.

The Company continues to analyze and monitor AMR technology.

d. The eight measures cited as critical factors in the future consideration of TOU rate design remain our best current metrics on formulating a strategy for future rate design.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 09/06/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Linda Gervais |
| TYPE: | Data Request | DEPT: | State and Federal Regulation |
| REQUEST NO.: | PC - 160 | TELEPHONE: | (509) 495-4975 |

**REQUEST:**

Please provide all comments submitted by Avista, or on its behalf, regarding smart meters or time-of-use pricing in WUTC Docket No. UE-060649.

**RESPONSE:**

Please see the attached comments provided by the Company in WUTC Docket No. UE-060649.

**[Avista Corporation Letterhead]**

**VIA ELECTRONIC MAIL**
<records@wutc.wa.gov>

August 14, 2007

Carol Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

**Re: Standards for Interconnection to Electric Utility Delivery Systems, WAC 480-108, Docket UE-060649**

**&**

**Re: Public Utility Regulatory Policies Act Standards, Docket UE-060649**
**PURPA Section 111(d) Standards:**
**(11) – Net Metering**
**(12) – Fuel Sources**
**(13) - Fossil Fuel Generation Efficiency**
**(14) – Smart Metering (Time-based Metering and Communications)**

Dear Ms. Washburn:

On July 9, 2007, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Opportunity to File Written Comments (Notice) on the proposed rule amendments governing the interconnection of customer-owned generating facilities to investor-owned electric utility delivery systems. On July 10, 2007, the Commission issued a second Notice in this Docket regarding whether new regulations are needed to govern the four PURPA Standards listed above. Avista Corporation (Avista) is providing the following comments in response to these Notices.

**General Comments**

In general, Avista supports the proposed amendments to the interconnection rules as developed by the Commission. Additionally, after review of PacifiCorp's comments, Avista generally supports PacifiCorp's comments filed in this Docket in response to the first Notice issued on July 9, 2007.

Avista also supports the Commission's determination not to adopt any new regulations addressing the four PURPA Standards. Furthermore, Avista supports the Commission's drafted Interpretive and Policy Statement in response to the second Notice issued on July 10, 2007, in this Docket.

Avista appreciates the opportunity to present their viewpoints and to participate in the stakeholder's review on these issues in the Commission's drafted amended rules and the drafted Interpretive and Policy Statement. Please direct any questions regarding these comments to the undersigned.

Sincerely,

James McDougall
Regulatory Analyst
Avista Corporation
(509) 495-2547
james.mcdougall@avistacorp.com

cc: Dick Byers – via e-mail dbyers@wutc.wa.gov

**VIA ELECTRONIC MAIL**
<records@wutc.wa.gov>

May 25, 2007

Carol Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

Re: *Public Utility Regulatory Policies Act Standards*
*Standards for Interconnection to Electric Utility Delivery Systems*
Docket UE-060649
Joint Comments of Puget Sound Energy, Inc. and Avista Corporation

Dear Ms. Washburn:

On April 30, 2007, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Opportunity to File Written Comments (Notice) on the draft amended rules governing the interconnection of customer-owned generating facilities to investor-owned electric utility delivery systems. Avista Corporation and Puget Sound Energy, Inc. provide the following joint comments in response to the Notice.

**General Comments**

In general, both Avista Corporation and Puget Sound Energy, Inc. support the draft interconnection rule as developed by the Commission. Additionally, after review of PacifiCorp's comments, both Avista Corporation and Puget Sound Energy, Inc. generally support PacifiCorp's comments filed in this docket in response to the Notice.

**Specific Comments**

Avista Corporation and Puget Sound Energy offer the following changes to the language provided in the draft rule language (changes to draft text are underlined for additions and striken-through for deletions).

**WAC 480-108-020(1)(f)(iii)**

(iii) Power quality. Installations must be in compliance with all applicable standards including, without limitation, the most current version of IEEE Standard 519-~~1992~~ Harmonic Limits, and IEEE Standard 141 Flicker as measured at the PCC.

**WAC 480-108-010**

**"Network distribution system (spot)"** means electrical service from a distribution system consisting of two or more primary circuits from one or more substations or transmission supply points arranged such that they collectively feed secondary circuits serving one or more electrical company customers not served from the grid.

Avista Corporation and Puget Sound Energy appreciate the opportunity to present their viewpoints on these issues in the Commission's draft amended rule. Please direct any questions regarding these comments to the undersigned.

Sincerely,

**Avista Corporation**

*James McDougall*
James McDougall
Regulatory Analyst
(509) 495-2547
james.mcdougall@avistacorp.com

**Puget Sound Energy, Inc.**

*Tom DeBoer*
Tom DeBoer
Director - Rates & Regulatory Affairs
(425) 462-3495
tom.deboer@pse.com

cc: Dick Byers – via e-mail dbyers@wutc.wa.gov

PC_DR_160-Attachment A

**VIA ELECTRONIC MAIL**
<records@wutc.wa.gov>

February 28, 2007

Carol Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

Re: Public Utility Regulatory Policies Act Standards
Standards for Interconnection to Electric Utility Delivery Systems
Docket UE-060649

Dear Ms. Washburn:

On January 25, 2007, the Washington Utilities and Transportation Commission (Commission) issued a Notice of Opportunity to File Written Comments (Notice) on the draft amended rules governing the interconnection of customer-owned generating facilities to investor-owned electric utility delivery systems. Avista Corporation and Puget Sound Energy, Inc. provide the following joint comments in response to the Notice.

**General Comments**

In general, both Avista Corporation and Puget Sound Energy, Inc. support the draft interconnection rule as developed by the Commission. Additionally, after review of PacifiCorp's comments, both Avista Corporation and Puget Sound Energy, Inc. generally support PacifiCorp's comments filed in this docket in response to the Notice.

**Specific Comments**

Avista Corporation and Puget Sound Energy offer the following changes to the language provided in the draft rule language.

**WAC 480-108-010 Definitions.**
WUTC draft amended language:

> **"Certificate of completion"** means the form described in WAC 480-108-050 that must be completed by the applicant or interconnection customer and the electrical inspector having jurisdiction over the installation of the facilities indicating completion of installation and inspection of the interconnection.

Avista and PSE proposed language:

> **"Certificate of completion"** means the form described in WAC 480-108-050 that must be completed by the applicant or interconnection customer and the electrical inspector having jurisdiction over the installation of the facilities indicating completion of installation and inspection of the interconnection. <u>The certificate of completion as provided in WAC 480-108-050 requires review and written preapproval by the electrical company before the applicant's or interconnection customer's generating facility can be connected or operated in parallel with the electrical company's electric system.</u>

**WAC 480-108-020 Technical standards for interconnection.**
**(2) Specific interconnection requirements**
WUTC draft amended language:

> **(d)** Nominal voltage and phase configuration of the applicant's generating facility must be compatible with the electrical company's system at the point of common coupling.

Avista and PSE proposed language:

> **(d)** Nominal voltage and phase configuration of the applicant's generating facility <u>require review and written preapproval by the electrical company for compatibility</u> ~~must be compatible~~ with the electrical company's system at the point of common coupling.

**WAC 480-108-020 Technical standards for interconnection.**
**(2) Specific interconnection requirements**
WUTC draft amended language:

> **(e)** The applicant must provide evidence that its generating facility will never result in reverse current flow through the electrical company's network protectors.

Avista and PSE proposed language:

(e) The applicant must provide evidence that its generating facility will never result in reverse current flow through the electrical company's system at the point of common coupling ~~network protectors~~.

**WAC 480-108-020 Technical standards for interconnection.**
**(2) Specific interconnection requirements**
WUTC draft amended language:

(g) Interconnection to grid network distribution systems is not allowed.

Avista and PSE proposed language:

(g) Interconnection to grid network distribution systems is prohibited unless allowed by the electrical company ~~not allowed~~.

**WAC 480-108-030 Application for interconnection.**
WUTC draft amended language:

**(3) Application prioritization.**
All generation interconnection requests pursuant to this chapter will be prioritized by the electrical company in the same manner as any new load requests. Preference will not be given to either request type. The electrical company will process the application and provide interconnection in a time frame consistent with the average of other service connections.

Avista and PSE proposed language:

**(3) Application prioritization.**
All generation interconnection requests pursuant to this chapter will be prioritized by the electrical company in the same manner as any new load requests. Preference will not be given to either request type. The electrical company will process the application and provide interconnection of the same type in a time frame consistent with the average of other service connections.

**WAC 480-108-050 Certificate of Completion.**
WUTC draft amended language:

All generating facilities must obtain an electrical permit and pass electrical inspection before they can be connected or operated in parallel with the electrical company's electric system. The interconnection customer must provide to the electrical company written certification that the generating facility has been installed and inspected in compliance with the local building and/or electrical codes.

Avista and PSE proposed language:

All generating facilities must obtain an electrical permit and pass electrical inspection before they can be connected or operated in parallel with the electrical company's electric system. The interconnection customer must provide to the electrical company written certification that the generating facility has been installed and inspected in compliance with the local building and/or electrical codes. <u>The certificate of completion requires review and written preapproval by the electrical company before the applicant's or interconnection customer's generating facility can be connected or operated in parallel with the electrical company's electric system.</u>

**WAC 480-108-070 Interconnection of Facilities Greater than 300 kW.**

WUTC draft amended language:

(1) No later than August 31, 2007, each electrical company over which the commission has jurisdiction must file interconnection service tariffs for facilities larger than 300 kW. Interconnection service, for purposes of this section, includes only the terms and conditions that govern physical interconnection to the electrical company's delivery system and does not include sale of power by the interconnecting customer or retail service to the interconnecting customer.

Avista and PSE proposed language:

(1) No later than <u>October 31, 2007,</u> ~~August 31, 2007~~, each electrical company over which the commission has jurisdiction must file interconnection service tariffs for facilities larger than 300 kW. Interconnection service, for purposes of this section, includes only the terms and conditions that govern physical interconnection to the electrical company's delivery system and does not include sale of power by the interconnecting customer or retail service to the interconnecting customer.

Avista Corporation and Puget Sound Energy appreciate the opportunity to present their viewpoints on these issues in the Commission's draft amended rule. Please direct any questions regarding these comments to the undersigned.

Sincerely,

**Avista Corporation**

James McDougall

James McDougall
Regulatory Analyst
(509) 495-2547
james.mcdougall@avistacorp.com

**Puget Sound Energy, Inc.**

Tom DeBoer

Tom DeBoer
Director - Rates & Regulatory Affairs
(425) 462-3495
tom.deboer@pse.com

cc: Dick Byers – via e-mail dbyers@wutc.wa.gov

August 11, 2006

Carole Washburn, Executive Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

Re: Avista Comments on the Public Utility Regulatory Policies Act Standards, Docket No. UE-060649

Dear Ms. Washburn:

Thank you for the opportunity to provide comments regarding the consideration of the Public Utility Regulatory Policies Act Standards in Docket No. UE-060649. Avista's comments are responsive to the questions, italicized below, contained in the Commission's June 9, 2006 Notice of Opportunity to File Written Comments.

Avista's comments herein address the time-based metering and communications questions beginning on page 7 of the Commission's inquiry. Regarding the questions beginning on page 9 on Interconnection issues, Avista is filing its response separately on this item as a joint respondent with other Washington utilities.

1) *Should the Commission, by rule, adopt PURPA Standard 14 – Time-Based Metering and Communications – to apply uniformly to PSE, Avista Utilities, and PacifiCorp requiring each utility to offer by February 8, 2007, a time-based rate to each customer class and the necessary time-based metering to individual customers upon request? Why, or why not?*

The Commission should not require by rule that, by February 8, 2007, PSE, Avista Utilities, and PacifiCorp offer a time-based rate to each customer class and the necessary time-based metering to individual customers upon request. Two components of such a requirement are problematic for Avista. First, at best it would be prohibitively expensive to install time-based metering and associated data storage and billing system upgrades by February 8, 2007. At worst, it would not be possible to acquire and install over 220,000 meters for Avista's Washington customers and the necessary computer system upgrades in a five month period. Second, the time-based metering "upon request" option by customers is not feasible. To the extent that time-of-use metering is cost-effective, then all customers would need to be metered. Meter installation and communication for data aggregation should be done neighborhood by neighborhood. It would not be economic to put time-of-use (TOU) meters onto customer premises only upon request, especially where it was not part of a wider installation plan in the area. If offered in a rate tariff, TOU could be by individual election, but from the utility perspective this is an "all or nothing" proposition.

Recent and past analyses of TOU by Avista show it is likely not cost-effective for Avista to implement TOU rates for all customer classes. The potential savings created by customers shifting their daytime demand into the night does not outweigh the cost of meter installation, software upgrades, and associated operational costs. TOU, however, could be cost-effective for our large industrial customers. These customers consume large quantities of power and already have sophisticated TOU-ready meters, making them potentially "low-hanging fruit."

A high-level study recently performed by Avista shows the value of Avista's on-peak/off-peak differential, combined with avoided capacity charges, to be under 1.5 cents per kilowatt hour. This value needs to be compared to the cost of metering, software, and operating costs for TOU implementation in our residential and small commercial customer classes, which represent over 50% of our customer usage. An approximate cost estimate of meter installation is $40 million. Additionally, the Company's preliminary cost estimate for associated data storage and billing system updates is $22 million. If the metering and billing costs are amortized over twenty years, then the Company would need to have a shifting of 7% percent of its load, 446 million kwh or 51 aMW, for this to be cost-effective. We would expect that with a 1.5-cent cost differential this would not be cost-effective. As mentioned earlier, however, there may be an opportunity for large industrial customers to provide load reduction through TOU programs with significantly less cost than through a total Company approach. The Company is examining this as part of its 2007 Integrated Resource Plan.

2) *Should the Commission examine and determine whether to adopt the Time-Based Metering and Communications Standard on a generic basis (i.e., applying the same requirements to all utilities), or should it consider the standard within separate proceedings specific to the circumstances of each utility?*

The Commission should examine and determine whether to adopt time-based metering and communication on a generic basis for the policy and principles underlying the consideration of TOU adoption. However, the Commission should consider the specific application of implementation of TOU in separate proceedings.

For the overall policy aspects in considering TOU adoption, issues common to all stakeholders will likely be discussed. Participation and perspectives of each utility should help inform others. Yet, there will likely be issues unique to each utility for implementation. The details for implementation may involve different metering equipment and architectural design of data collection. The power supply cost profiles (e.g., the value of on-peak versus off-peak costs) may also be different. If the Commission adopts TOU pricing, the same type of rate schedule should not be required of all utilities and for all rate classes.

3) *Should the Commission reject, reiterate or modify its policy enunciated in Cause U-78-05 that time-of-day rates are appropriate so long as they are cost-effective?*

The Commission Decision and Order in Cause No. U-78-05 at page 7 states:

> "Basically, this standard says that rates to classes of electric customers shall be on a time-of-day basis unless it is determined that time-of-day ratemaking is not cost-effective to the utility and its customers. We agree with this standard, and believe it should be adopted.
>
> "Amendments were offered, such as utilizing cost-justified metering only and 1,000 KW loads or greater only, but we believe that the limitations thus proposed are included within the language of the standard as it presently exists. Basically, time-of-day ratemaking is acceptable only if cost-justified. Other parties proposed to reject the PURPA standard because there is allegedly no showing that it is presently cost-justified at all within Washington State. Allusion was made to metering costs and present high load factors, and rejecting the standard was suggested for a specific class such as residential because metering is not shown to be cost effective as to that class.
>
> "Again, the proposals to reject the standard are based upon a judgment that under existing circumstances, time-of-day metering and rates may be not cost justified. We believe that the standard itself is flexible enough to accommodate to present circumstances as well as any future circumstances and believe it more appropriate to adopt the standard, with its flexibility, than to reject or amend the standard under present facts but thus to be without a stated policy in the event of future changes in load or generation patterns.

> "Finally, it is urged that high daily load factors limit achievable savings and that a shifting of loads off peak could hamper reservoir refills or otherwise lead to inefficient use of power and resources. We believe that those factors are factors which we and the utilities may properly consider under that standard in terms of the cost-benefit analysis as "other costs associated" with the use of time-of-day rates."

Avista believes that the policy enunciated in Cause U-78-05 that time-of-day rates are appropriate so long as they are cost-effective should be reaffirmed. The Commission appropriately placed an emphasis on cost-effectiveness and noted that flexibility is built into the now-existing standards.

4) *What factors should the Commission consider in determining whether time-based rates and metering are cost-effective?*

The Commission, in determining whether time-based rates and metering are cost-effective, should consider the following factors.

A) The economic value of the difference between on-peak and off-peak wholesale costs. This value has two components, cost and volume. The value should show how much energy must be purchased by utilities for these periods if customers do not reduce the need for this power by shifting usage from on-peak to off-peak periods.
B) The economic value of deferred capacity installation
C) The economic value, if any, associated with additional information gathered through TOU metering systems (e.g., load research data).
D) The costs of meter installation.
E) The costs of data storage, billing, and other associated functions to enable TOU pricing.
F) Rate equity issues. Some customers have the flexibility to shift usage into off-peak hours. Some don't. This will create a situation in which some customers may experience lower bills and others higher. The significance of this should be addressed.
G) Process. Would movement to TOU rates need to be addressed in a general rate case or could this be done in a tariff filing?
H) The time to install and put into operation TOU meters and associated equipment.

5) *If the Commission adopts the Time-Based Metering and Communications Standard, which, if any, of the 4 listed types of time-based rate schedules should be required? Should the same type of rate schedule be required of all utilities and for all rate classes?*

If the Commission adopts a time-based metering and communications standard, of the four listed types of time-based rate schedules, Avista suggests that only time of use pricing be required, based on cost-effectiveness. The second and third categories, critical peak pricing and real-time pricing, respectively, should be considered at a later time based, in part, on customer response to time of use pricing, if implemented. The fourth category, credits for consumers with large loads who enter into pre-established peak load reduction agreements, has been implemented by Avista on several occasions. In late 2000, the Company instituted a large-customer buy-back program. More recently, on July 17, 2006, Avista implemented bi-lateral agreements with three customers at a time of near-record temperatures.

6) *What, if any, relationship should there be between a utility's integrated resource plan and its use of time-based metering, time-of-use rates and demand management programs?*

Avista submits that there is a relationship from a planning perspective for the consideration of time-based metering, time-of-use rates and demand-side-management. Peak shaving and peak shifting through TOU and other demand-response programs are analyzed in the IRP planning process as a means to defer or avoid higher cost alternatives such as a peaking natural gas combustion turbine.

The IRP process is the appropriate venue for TOU evaluation. The IRP, by definition, is an exercise in evaluating future resource options, including conservation and demand-side management. The IRP would account not only for energy savings, but also deferred capacity acquisition. A TOU evaluation would be an extension of existing IRP analysis, and could be completed on a class-by-class basis without a significant need for new modeling. Avista's work plan for its 2007 IRP incorporates a TOU evaluation. Commission Staff and other IRP participants will be provided an opportunity to comment on this analysis.

7) *Are there other issues the Commission should consider in this Inquiry?*

Yes. The Company notes that time-of-use metering and pricing has been considered by utilities periodically. Avista reviews the cost-effectiveness of TOU on an ongoing basis. This is also included in its IRP analyses. However, if the Commission prefers to codify a requirement for TOU determination and applicability, it may be appropriate to consider requiring by rule a periodic assessment of TOU pricing through the IRP process.

Thank you for the opportunity to comment on these proposed rules. Please direct any questions on this matter to me at (509) 495-8706.

Sincerely,

Bruce Folsom,
Manager, Regulatory Compliance

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 7/27/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Heather Cummins |
| TYPE: | Data Request | DEPT: | Distribution Engineering |
| REQUEST NO.: | PC - 55 | TELEPHONE: | (509) 495-4430 |

**REQUEST:**

Re: Testimony of Heather Cummins, Exhibit No. ___ (HLC-2):

Please provide the following information regarding Avista's estimates of its meter program costs presented on page 2 of Exhibit No. ___ (HLC-2):

a. Please identify the type of meter technology underlying the estimate for electric meters in phase I.

b. Please identify the $/meter loaded estimate for electric meters in phase I.

c. Does the type of meter technology underlying the estimate for electric meters in phase I require corresponding incremental costs to modify billing systems and, if so, what are those costs and are they included in the estimated of $/meter loaded.

d. Please identify the type of meter technology underlying the estimate for gas meters in phase I.

e. Please identify the $/meter loaded estimate for gas meters in phase.

f. Does the type of meter technology underlying the estimate for gas meters in phase I require corresponding incremental costs to modify billing systems and, if so, what are those costs and are they included in the estimated of $/meter loaded.

g. Does the type of meter technology underlying the estimate for electric meters in phase I require corresponding incremental costs to modify billing systems and, if so, are those costs included in the estimated of $/meter loaded.

h. Please identify the type of meter technology underlying the estimate for electric meters in phase II low case.

i. Does the type of meter technology underlying the estimate for electric meters in phase II low case require corresponding incremental costs to modify billing systems and, if so, what are those costs and are they included in the estimated of $/meter loaded.

j. Please identify the $/meter loaded estimate for electric meters in phase II high case.

k. Please identify the type of meter technology underlying the estimate for electric meters in phase II high case.

l. Does the type of meter technology underlying the estimate for electric meters in phase II high case require corresponding incremental costs to modify billing systems and, if so, what are those costs and are they included in the estimated of $/meter loaded.

**RESPONSE:**

a. The type of meter technology underlying the estimate for electric meters in phase I is digital meters with Power Line Carrier modules. Phase I covers meter installations in the rural areas.

b. The loaded estimate for electric meters in phase I is $236/meter.

c. There are no incremental costs required to modify the billing systems to accept monthly billing information for electric meters in phase I. However, to implement Time Of Use (TOU) billing capabilities, the meter technology will require corresponding incremental costs to modify the billing system. The corresponding incremental costs to modify the billing system for TOU are not included in the estimated $/meter loaded value. These costs are being evaluated separately and have not yet been determined.

d. The gas meters will not be changed out; they will have a one-way radio-based communication module installed on them.

e. The loaded estimate for gas meter upgrades in phase I is $75/meter.

f. There are no incremental costs required to modify the billing systems to accept monthly billing information for gas meters in phase I.

g. Please see response to c.

h. The type of meter technology underlying the estimate for electric meters in phase II low case is digital meters with one-way radio-based communication technology. Phase II covers meter installations in the urban areas.

i. Yes, the meter technology will require corresponding incremental costs to modify the billing systems to enable monthly billing or TOU billing. The corresponding incremental costs to modify billing systems are not included in the estimated $/meter loaded value. Theses costs are being evaluated separately and have not been determined yet.

j. The loaded estimate for electric meters in phase II high case is $200/meter.

k. The type of meter technology underlying the estimate for electric meters in phase II high case is digital meters with two-way radio-based communication technology. Phase II covers meter installations in the urban areas.

l. Yes, the meter technology will require corresponding incremental costs to modify the billing systems to enable monthly billing or TOU billing. The corresponding incremental costs to modify billing systems are not included in the estimated $/meter loaded value. Theses costs are being evaluated separately and have not been determined yet.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 09/07/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Heather Cummins |
| REQUESTER: | Public Counsel | RESPONDER: | Heather Cummins |
| TYPE: | Data Request | DEPT: | Distribution Engineering |
| REQUEST NO.: | PC - 159 | TELEPHONE: | (509) 495-4430 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 8, lines 10 to12 and Avista's Response to Public Counsel DR- 34.

The response to PC 034 (b) is limited to urban areas. Does Avista plan to evaluate time-of-use or critical-peak pricing in rural areas also? Please explain why or why not.

**RESPONSE:**

The current system planned to be deployed in rural areas is capable of supporting hourly interval data which would provide the foundation for time-of-use or critical-peak pricing. However, before the decisions are made, more research and evaluation will need to be done concerning the value of time-of-use critical peak pricing, the cost of supporting billing system modifications required to support this type of pricing, and other customer communication methods available to deliver this real-time information to customers.

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Washington | DATE PREPARED: | 9/11/2007 |
| CASE NO: | UE-070804 & UG-070805 | WITNESS: | Bruce Folsom |
| REQUESTER: | Public Counsel | RESPONDER: | Lori Hermanson |
| TYPE: | Data Request | DEPT: | Energy Solutions |
| REQUEST NO.: | PC - 162 | TELEPHONE: | (509) 495-4658 |

**REQUEST:**

Re: Testimony of Heather Cummins, page 8, lines 10 to 12.

Please indicate whether Avista believes it is appropriate to consider the costs associated with achieving load reduction in determining whether time-based rates and meters are cost-effective, including costs associated with fuel switching, energy efficiency, and customer hardship. Does Avista agree that this additional category of costs should be included in the evaluation of cost-effectiveness? Please explain why or why not.

**RESPONSE:**

Monetary costs associated with implementing a TOU rate structure, specifically the costs of appropriate metering and changes to the customer billing system, should certainly be considered within any cost-benefit analysis of a TOU rate proposal. Improving the price signal will impact customer decisions to include fuel-choice and energy-efficiency investments; choices between energy cost at various TOU periods and the value of energy consumption are an integral component of the consumer price response that is at the core of the benefits of improving the price signal.

# Avista Electric Rate Changes 2000-2006

| | UE-011143 | UE-010395 | UE-011595 | UE-011595 * | UE-021124 | UE-021731 | UE-041795 | UE-050482 | Total Change |
|---|---|---|---|---|---|---|---|---|---|
| | **Res Exc Cr** | **Temp Surch.** | **Interim** | **General** | **Res Exch Cr** | **Res Exch Cr** | **Res Exch Cr** | **Rate Case** | |
| Date Effective | October-01 | October-01 | April-02 | June-02 | October-02 | February-03 | November-04 | January-06 | |
| **Electric Annual Revenue Change:** | | | | | | | | | |
| AVISTA Requested | $ (7,900,000) | $87,387,000 | $29,344,000 | $0 | ($600,000) | $1,400,000 | ($3,400,000) | $35,800,000 | |
| AVISTA Granted | $ (7,900,000) | $59,200,000 | $14,672,000 | $0 | ($600,000) | $1,400,000 | ($3,400,000) | $22,135,000 | |
| % Change in Revenues - Requested | | 36.9% | 12.4% | 0.0% | | | | 12.5% | |
| % Change in Revenues - Granted | | 25.0% | 6.2% | 0.0% | | | | 7.7% | |
| **Monthly Residential Bill Change:** | | | | | | | | | |
| AVISTA Requested | $ (3.50) | $17.11 | $5.83 | | ($0.29) | $1.02 | ($1.44) | $7.92 | |
| **AVISTA Granted** | **$ (3.50)** | **$11.03** | **$2.91** | | **($0.29)** | **$1.02** | **($1.44)** | **$4.90** | **$ 14.63** |
| | | | | | | | | | |
| Total WA Electric Revenues | | $236,551,878 | $236,551,878 | $236,551,878 | | | | $285,942,492 | |

* No overall rate change, but a reallocation of revenues from the surcharge to base rates

Source: WUTC Electric & Gas Comparison of General Rate Cases and Purchase Gas Adjustments 2000 to Present
Available at: http://www.utc.wa.gov/webimage.nsf/e827858488fbdbaa88256efc00506bb3/dcf99908409a29448825709700726f24!OpenDocument

# Avista Natural Gas Rate Changes 2000-2006

| | UG-001932 | UG-010976 | UG-021258 | UG-031361 | UG-041515 | UG-041515 | UG-051372 | UG-050483 | UG-061513 | Total Change |
|---|---|---|---|---|---|---|---|---|---|---|
| | **PGA** | **PGA** | **PGA** | **PGA** | **Rate Case** | **PGA** | **PGA** | **Rate Case** | **PGA** | |
| Date Effective | January-01 | August-01 | November-02 | September-03 | November-04 | November-04 | November-05 | January-06 | October-06 | |
| **Natural Gas Annual Revenue Change:** | | | | | | | | | | |
| AVISTA Requested | $33,900,000 | $17,690,000 | ($28,900,000) | $11,900,000 | $8,600,000 | $17,300,000 | $38,600,000 | $2,900,000 | $16,700,000 | |
| AVISTA Granted | $33,900,000 | $17,690,000 | ($28,900,000) | $11,900,000 | $5,370,000 | $17,300,000 | $38,250,000 | $968,000 | $2,700,000 | |
| % Change in Revenues - Requested | 32.3% | 12.7% | -18.8% | 7.5% | 6.1% | 12.4% | 23.5% | 1.4% | 8.1% | |
| % Change in Revenues - Granted | 32.3% | 12.7% | -18.8% | 7.5% | 3.8% | 12.4% | 23.3% | 0.5% | 1.3% | |
| **Monthly Residential Bill Change:** | | | | | | | | | | |
| AVISTA Requested | $14.02 | $7.04 | ($12.91) | $5.20 | $4.47 | $8.26 | $16.39 | $1.48 | $7.36 | |
| **AVISTA Granted** | **$14.02** | **$7.04** | **($12.91)** | **$5.20** | **$2.79** | **$8.26** | **$16.24** | **$0.49** | **$1.19** | **$42.33** |
| | | | | | | | | | | |
| Total WA Revenues | $105,044,579 | $138,944,579 | $154,076,856 | $158,327,266 | $140,000,000 | $140,000,000 | $164,445,000 | $202,695,000 | $205,000,000 | |

**Source: WUTC Electric & Gas Comparison of General Rate Cases and Purchase Gas Adjustments 2000 to Present**

**Available at: http://www.utc.wa.gov/webimage.nsf/e827858488fbdbaa88256efc00506bb3/dcf99908409a29448825709700726f24!OpenDocument**