BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. AVISTA CORPORATION, D/B/A AVISTA UTILITIES, Respondent.	)	DOCKET NO. UE-050482 and DOCKET NO. UG-050483

BRIEF OF AVISTA CORPORATION

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TABLE OF CONTENTS

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1 COMES NOW, Avista Corporation (hereinafter "Avista" or the "Company"), and by and through its undersigned counsel, respectfully submits this post-hearing Brief in the above-captioned matter.

I. INTRODUCTION

A. Brief History of the Proceeding and Ultimate Issue Before the Commission.

2 On March 30, 2005, Avista filed proposed tariff revisions requesting an increase in electric rates of $35,833,000, representing a 12.5% increase in base retail rates. At the same time, Avista also requested an increase in natural gas rates of $2,943,000, or 1.7%. (Exh. 1, p. 4, ll. 8-13.) The Company had proposed a rate of return of 9.67%, based on a common equity ratio of 44.0% and an 11.5% return on equity. (Id.)

3 After a lengthy period of discovery and at the conclusion of several settlement conferences, a multi-party Settlement Agreement (hereinafter "Settlement") was reached and filed with the Commission on August 12, 2005. The process leading up to this Settlement will be discussed in more detail below. A copy of the Settlement was introduced as Exhibit 2 in this proceeding. Joining in the Settlement were Avista, the Staff of the Commission, the Northwest Industrial Gas Users ("NWIGU") and the Energy Project. The Office of Public Counsel and the Industrial Customers of Northwest Utilities ("ICNU") did not join in the Settlement.

4 The parties to the Settlement have requested that the Commission approve the agreement, as being in "the public interest." Indeed, much of the rest of this Brief is devoted to explaining why the agreement comports with the public interest. Procedurally, however, WAC 480-07-750 provides that the Commission may accept (with or without conditions) or reject settlements. More specifically, Section 1 of the rule provides, in pertinent part, that the Commission "will approve settlements when doing so is lawful, the settlement terms are supported by an appropriate record, and when the result is consistent with the public interest in light of all the information available to the Commission."

5 It is noteworthy that the Commission, in this proceeding, is <u>not required to approve an alternative revenue requirement</u> at this time, should the Settlement be rejected. WAC 480-07-750(2) provides that, if the Commission rejects a settlement, "the litigation <u>returns to the status at the time the settlement was offered</u> and the time for completion of the hearing will be extended by the elapsed time for consideration of the settlement." (Emphasis added.) Stated differently, instead of arriving at an alternative revenue requirement as a result of its review of the Settlement, this Commission would return the matter to its prior status as a contested case.

6 The following sections of this Brief will address how the Settlement is supported by an "appropriate record" and how it is "consistent with the public interest in light of all the evidence available to the Commission." (Id.) While the Company had originally filed for $35.8 million in increased electric rate relief and $2.9 million in increased natural gas revenues, as explained below, were this matter to be litigated, the evidence would still support a revenue requirement of $33.4 million for electric and $2.6 million for natural gas service. (Exh. 11, p. 22, ll. 3-10.) The joint testimony of the signing parties (Exh. 1), as well as the testimonies of various Company and Staff witnesses rebutting the arguments of Public Counsel and ICNU, provide strong support for the Settlement.

7 Stated differently, were this case to be litigated, the evidence would strongly support a revenue requirement equal to or greater than the dollar amounts included in the Settlement, as evidenced by Avista's revised litigation position of $33.4 million for electric and $2.6 million for natural gas. Apart from resolving revenue requirement issues, the Settlement also has other noteworthy aspects that bear on the "public interest." It provides for a substantial increase in low-income DSM and LIRAP funding; it implements an agreed-upon "equity building mechanism" that reaffirms the Company's commitment to improve the equity component of its capital structure; it reduces the ERM deadband which would be viewed favorably by the financial community as the Company continues to work toward an investment-grade credit rating; and finally, it better aligns rate spread and rate design with cost of service. (Exh. 11, p. 23, ll. 3-11.) Simply put, the Settlement produces an "end result" that is in the "public interest" and will serve to improve the Company's financial condition.

B. Commission Precedent Regarding Settlements.

8 RCW 80.28.010(1) (Duties as to Rates, Services, and Facilities) provides that "all charges made, demanded or received by any gas company, electrical company . . . shall be just, fair, reasonable and sufficient." Moreover, RCW 80.28.020 provides this Commission with authority to fix just, reasonable and compensatory rates:

9 > Whenever the commission shall find . . . that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and enforced, and shall fix the same by order.

10 (Emphasis supplied.) As the Supreme Court explained in the Hope Natural Gas case, the requirement that rates be "fair, just and reasonable" does not define a method by which rates are to be calculated; instead, the fixing of fair, just and reasonable rates involves a balancing of investor and consumer interests. Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). Simply put, the "end result" must be reasonable. These standards have been incorporated into RCW 80.28.010 and 80.28.020, as set forth above.

11 Accordingly, this Commission is given broad powers in making rate-setting decisions. U.S. West Communications, Inc. v. Washington Utilities & Transp. Comm'n, 134 Wn.2d 74, 949 P.2d 1337 (1997). In the process, the Commission must, in each rate case, attempt to not only assure fair prices and service to customers, but also "assure that regulated utilities earn enough to remain in business – each of which functions is as important in the eyes of the law as the other."[1]

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[1] People's Organization for Washington Energy Resources (POWER) v. Utilities & Transp. Comm'n, 104 Wn.2d 798, 808, 711 P.2d 319 (1985) (citing, State ex rel. Puget Sound Power & Light Co. v. Department of Pub. Works, 179 Wash. 461, 466, 38 P.2d 350 (1934)).

Accordingly, the Commission is obligated to balance both investor and consumer interests.[2]

12 As this Commission observed at page 27 of its Order No. 06 (Docket No. UE-032065), which approved a recent settlement involving PacifiCorp:

> 13 Ratemaking is not an exact science. As our Supreme Court has observed: '[t]he economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result.' (U S West, supra, 134 Wn.2d at 70.)

14 More recently, this Commission has again recognized, in the context of approving settlements, that the ultimate test is whether resulting rates are "fair, just and reasonable." In this Commission's recent Order No. 03 approving the Verizon settlement, issuing on April 12, 2005, the Commission observed:

> 15 This proposed settlement occurred late in the litigation process, after extensive discovery and production of information. It occurred after thorough analysis by the parties, which was described during the hearings. Settlement occurred after the parties' testimony was filed, making clear their litigation positions. . . . as a result, we have confidence that the proposed rates are fair, just and reasonable, as required by RCW 80.04.130. (Docket No. UT-040788.)

16 (Emphasis added.) (Id. at ¶¶ 18-19.) The same could be said of the Settlement reached in this case. It occurred after extensive discovery and production of information, and on the eve of the pre-filing of direct testimony, at a point at which all parties' litigation positions should have been evident. This was followed by extensive hearings providing contesting parties with the full and complete opportunity to argue their litigation positions, and for the Company and Staff to respond. Accordingly, a full and complete record was developed, allowing this Commission to reach the ultimate finding that the Settlement rates are "fair, just and

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[2] "The public interest is served when the interests of the utility and the interest of the utility's customers are kept in careful balance." In re the Matter of Avista Corp., Docket No. UE-010395, Sixth Supp. Order Rejecting Tariff Filing, ¶ 7 (September 24, 2001). The public interest standard, of course, encompasses a broad set of interests. See, e.g., Application of Puget Sound Energy re: Colstrip, Third Supp. Order Approving Sale, Docket No. UE-990267 (September 30, 1999).

reasonable." It is this "end result," which balances the interests of consumers and investors alike, that is the objective of this process.

II. THE PROCESS CULMINATING IN THE SETTLEMENT PROVIDED AMPLE OPPORTUNITY TO REVIEW THE COMPANY'S BOOKS AND RECORDS AND TO ENGAGE IN MEANINGFUL SETTLEMENT DISCUSSIONS

A. More Than Sufficient Time was Allotted the Parties for Discovery and Audit of the Company's Books and Records.

17 The Company originally filed for rate relief on March 30, 2005, nearly five months before a Settlement was reached in this matter. During that time, Staff and all interested parties had sufficient time to complete extensive discovery and arrive at their so-called "litigation" positions. Indeed, the first of three settlement conferences, originally scheduled for June of 2005, was postponed a month until July 27th of this year. It is reasonable to assume that all parties would have substantially completed their discovery of Avista and arrived at a position on any issues to be contested, by the end of the Settlement process — which was shortly before the August 26, 2005, pre-filing date for Staff and Intervenor testimony.

18 In his testimony, Staff witness Braden described how Staff was actively involved and "thorough in its review of issues." (Exh. 4, p. 1, ll. 19-20.) In his words:

> 19 In the process, Staff devoted the time and energy of several of its members to understanding the issues, auditing the books and records of the Company and examining every accounting adjustment proposed by the Company. Staff propounded 165 data requests of its own, and reviewed the Company's responses to all other requests of other parties. In doing so, it became well-acquainted with the issues and reached an informed decision that the Settlement was in the public interest. (Id. at ll. 8-15.)

20 Accordingly, after completion of its audit work, Staff exercised "its informed judgment of what was in the public interest," as explained by Mr. Braden, after taking into account the

results of its own audit work and other discovery as well as its assessment of litigation positions and prior Commission precedent. (Id. at ll. 19-23.)[3]

B. The Settlement Itself Incorporates Many Issues Raised by Public Counsel and ICNU.

21 As previously noted, three separate settlement discussions were held with all parties, including Public Counsel and ICNU. Information was freely shared during the process and all issues were fully explored. The Settlement, as finally reached, attempted to take into account a variety of issues that were raised by Public Counsel and ICNU in the process, even though they did not ultimately join in the Settlement. As confirmed through the cross-examination of Public Counsel witness Dittmer, the Settlement incorporates three of Public Counsel's seven electric rate base proposed adjustments and four out of ten of its net operating income adjustments. (Tr., p. 793, ll. 19-25.)[4] Furthermore, with respect to the gas revenue

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[3] Staff witness McIntosh was challenged, during cross-examination by intervenors, with respect to the settlement in relation to the timing of certain data requests. In response to questioning by Chairman Sidran, however, Mr. McIntosh responded as follows:

> Q: My question is, did you review all of the materials that were submitted in response to these data requests, albeit they may have come in after the settlement agreement?
> A: Yes.
> Q: And did your review of these materials have [any] impact on your opinion as to the reasonableness of the settlement?
> A: It confirmed my opinion.

(Tr., p. 234, ll. 16-p. 235, ll. 6.)

[4] The following seven adjustments, originally proposed by Public Counsel in its direct case, were, in fact, incorporated into the Settlement: (1) Colstrip AFUDC rate base adjustment (electric); (2) Colstrip Common AFUDC rate base adjustment (electric); (3) Customer Deposits rate base and NOI adjustment (electric/gas); (4) American Jobs (Tax Act of 2004) NOI adjustment (electric); (5) Kettle Falls Production Tax Credit NOI adjustment (electric); (6) Amortization of Cancelled Production Facilities NOI adjustment (electric); (7) Promotional Advertising NOI adjustment (gas).

requirement, the Settlement incorporated all of Public Counsel's rate base adjustments and two out of three of its net operating adjustments. Furthermore, as acknowledged by the Public Counsel witness, the Settlement included a number of additional adjustments resulting from Staff's audit work, that Public Counsel, itself, did not propose in its original direct case, but proposed in its rebuttal filing.[5] (Tr., p. 796, ll. 17-p. 797, ll. 4.) Simply put, the parties to the Settlement actively sought out the views of Public Counsel and ICNU, and where appropriate, incorporated their views in the Settlement.

22 Finally, this Commission, through its settlement hearing process, has fully afforded opponents of the proposed Settlement the opportunity to present their case in opposition. WAC 480-07-740(2)(c) provides the parties, who are opposed to the Settlement, the opportunity to cross-examine witnesses, and to present evidence and argument in support of their preferred result. That was done in this case.

III. THE SETTLEMENT IS "IN THE PUBLIC INTEREST"

23 In the final analysis, the Settlement represents a negotiated compromise among the signing parties. That is the nature of any settlement process. In the words of Staff witness Braden, it "appropriately balances the competing interest of the parties and is in the public interest." (Exh. 4, p. 1, ll. 6-7.) In the final analysis, however, "judgment must be brought to bear on the question of whether to settle this case," as explained by Mr. Braden. (Id. at p. 2, ll. 2-11.) From Staff's perspective, given its assessment of the merits of the positions of all parties, and the results of its own audit work, Staff concluded that ". . . the Settlement

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[5] These additional adjustments include (1) Pole Rental Revenues; (2) Amortized Gains on Sales of Real Property; (3) Eliminate Expiring Computer Lease Costs; and (4) a Consolidated Adjustment noted as Miscellaneous Below-The-Line Expense Elimination.

represents a just, fair and reasonable compromise of the competing interests presented in this case when they are considered as a whole." (Id. at ll. 9-12.)

24 The joint testimony of the signing parties concluded with observations explaining why the Settlement was "in the public interest." (See Exh. 1, p. 38, ll. 12-p. 39, ll. 5.) First of all, it strikes a reasonable balance between the interests of the Company and its customers, including low income customers; as such, it represents a "reasonable compromise among differing interests and points of view." (Id.) Furthermore, the Settlement will assist the Company in regaining its financial strength and thereby improve the prospects for an investment-grade credit rating. Moreover, the filing has been subjected to extensive discovery, with the Company responding to over 615 data requests; for its part, Staff assigned six members to participate in the audit of the Company's books and records for the purpose of reviewing normalizing and pro forma adjustments, capital structure and rate of return, along with rate spread and rate design. All parties have been given ample opportunity to participate meaningfully in the Settlement process, through the three settlement conferences noted above.

25 In the final analysis, however, as noted in the joint testimony, any settlement, by its very nature, reflects compromise in the give-and-take of negotiations. This Settlement, as presented, produces an "end result" or outcome that is squarely in the "public interest." Moreover, the Settlement addresses a broad spectrum of issues, not just revenue requirements. As earlier noted, it provides for increased funding for low-income DSM and LIRAP programs, it incorporates an "equity building mechanism," it reduces the deadband in the ERM and better aligns rate spread and rate design with cost of service. It also provides that the Company will not increase natural gas base rates prior to July of 2007. As such, the Settlement represents a "package" of different components and should be viewed as a whole.

IV. THE SETTLEMENT IS SUPPORTED BY THE RECORD AND COMMISSION PRECEDENT

26 Before addressing the particulars of the Settlement, it is helpful to understand the Company's litigation position, were this matter to be fully litigated.

A. Avista's Litigation Position, Were the Settlement Rejected.

27 In its rebuttal testimony, the Company reassessed its litigation position in this proceeding, were the Settlement to be rejected. It took into account the discovery completed to date, all settlement discussions, and a review of the testimony of Public Counsel and ICNU. In his rebuttal testimony (Exh. 11), Company witness Norwood, at page 5, sets forth the revisions to Avista's original filing, which would represent the Company's litigation position, absent a settlement. Mr. Norwood demonstrates that Avista's electric and natural gas additional revenue requirements would be $33.4 million and $2.6 million, respectively. This should be contrasted with the Company's original request of $35.8 million for an electric revenue increase, and $2.9 million for the natural gas increase. The agreed-upon revenue requirement in the Settlement of $22.1 million for electric and $968,000 for natural gas represents, by any measure, a substantial reduction from Avista's litigation position.

28 When comparing revenue requirements set forth in the Settlement ($22.1 million/electric) with the litigation positions of Public Counsel and ICNU, one notes that much of the difference can be explained by a relatively few adjustments. For example, were one to adopt the Settlement figure of 10.4% for return on equity (ROE) instead of Public Counsel's proposed 9.25%, this adjustment, alone, would explain $5.9 million of the difference in revenue requirement. In addition, the elimination of the Production Property Adjustment, as proposed by Mr. Lott of Public Counsel, would increase the Company's

revenue requirement by an additional $2.4 million, as compared with Public Counsel's case.[6] As testified to by Mr. Norwood, "these two adjustments alone total $8.3 million, and would increase Public Counsel's revenue increase level from $11.7 million [as set forth in its initial August 26 testimony] to $20.0 million, as compared to the proposed Settlement Agreement increase of $22.1 million." (Exh. 11, p. 3, ll. 13-17.) And, as Mr. Norwood goes on to explain, the acceptance of even "a portion of the Company's rebuttal" in connection with other adjustments made by Public Counsel would "result in a revenue increase to Avista that is well above the $22.1 million that the Company has agreed to accept in the Settlement." (Id. at ll. 18-21.)

29 It is true that, on rebuttal, Public Counsel further revised downward its recommended revenue requirement increase of $11.7 million to $6.4 million (electric). (See Exh. 235, p. 3.) However, much of this downward adjustment is based on Public Counsel's adoption of ICNU's positions with respect to a variety of power supply adjustments – adjustments which have been discredited by the Company's rebuttal. In this brief, the Company will proceed, point by point, to address each of the adjustments recommended by Public Counsel and ICNU. Nevertheless, the Company wishes to emphasize that most of the difference between the Settlement level of revenue requirement and the litigation positions of the parties is explained away by relatively few adjustments that have been fully addressed by Avista in the record.

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[6] As explained below, Mr. Lott's adjustment would result in "double counting," given the existence of the Retail Revenue Credit adjustment in the ERM.

B. The Agreed-Upon Return on Equity of 10.4% is Well Supported by the Record.

30 Avista and the other settling parties agreed upon a return on equity of 10.4%. This should be contrasted with Public Counsel's proposed ROE of 9.25%, as set forth in Mr. Hill's testimony (Exh. 261) and Mr. Gorman's testimony on behalf of ICNU, who argued for 9.8% (Exh. 331). A 10.4% ROE, as set forth in the Settlement, is, by any reasonable measure, conservative when viewed against the backdrop of the evidence in this case, as will be discussed below. It was the result of a compromise on a number of different issues which was necessary to arrive at a "settlement package" that reflected the give-and-take of negotiations.

31 As characterized by Dr. Avera, the recommendations of Mr. Hill and Mr. Gorman are "significantly downward-biased and out of touch with requirements of real-world investors in the capital markets." (Exh. 62, p. 2, ll. 10-16.) Simply put, the ROE recommendations of Public Counsel and ICNU fail the most fundamental test of reasonableness because they "do not provide Avista with the opportunity to earn returns that are comparable with those available from alternative investments of comparable risks," as testified to by Dr. Avera. (Id. at p. 3, ll. 8-27.) One can begin by examining the presently authorized average return on equity for Mr. Hill's own sample group, which is 10.67% — this is approximately 142 basis points higher than his own ROE recommendation. (Id.) Likewise, the data relied upon by Mr. Gorman, on behalf of ICNU, indicated an average ROE for the utilities in his comparable group of 10.95% — which exceeds his recommended ROE by 115 basis points. (Id. at p. 3, ll. 19-21.) Furthermore, Value Line reports that its analysts expect an average return on common equity for the electric utility industry of 11.0% for 2008-2010 (firms in the natural gas industry were expected to earn a return on common equity of 12.5%). (Id. at ll. 22-27.)

32 Interestingly enough, the agreed-upon equity component of the capital structure in the Settlement of 40% — which is not contested by any intervenor — is also below the average equity component of Mr. Hill's own proxy group of 43% and of Mr. Gorman's proxy group of 43%. On cross-examination, Mr. Hill acknowledged the obvious: (1) that his own proxy group had higher authorized ROEs than 10.4%; (2) that his own proxy group had average equity capitalization rates higher than 40%; and (3) that Avista has greater financial risk. (See, Tr. p. 787, ll. 17-p. 788, ll. 5.)

33 Yet another benchmark is recent data for average authorized returns for utilities during the first half of 2005. As discussed in both the Joint Testimony and in Dr. Avera's rebuttal, rates of return on common equity authorized for electric utilities by regulatory commissions across the company are compiled by the Regulatory Research Associates (RRA) and are published in its Regulatory Focus Report. (See Exh. 1, p. 14, ll. 13-18.) (Exh. 62, p. 7, ll. 10-15.) RRA, in its July 6, 2005 publication, reported that average equity return authorizations by state commissions nationwide for the first six months of 2005 was 10.36% for electric utilities (based on 16 rate cases) and 10.56% for natural gas utilities (based on 8 rate cases). (Id.) Accordingly, the 10.4% return on equity arrived at through Settlement in this case falls well within the recently reported average ranges. Mr. Braden described references to these national averages for approved ROEs as a useful "sanity check":

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> . . . the reference to the ROE report is what I would call a sanity check. When you have . . . [had] a negotiation and you have arrived at a number, you raise your head up, you look around and say does this make sense, and this was a factor we considered in determining that that was a reasonable compromise number.

(Emphasis added.) (Tr., p. 288, ll. 9-15.)

35 The Commission, at page 32 of its Order, in the recent Puget case, ultimately referred to "the common sense approach" as a useful check on its decision; it noted that establishing the proper return on equity is, in the final analysis "an exercise in informed judgment":

> 36 Establishing the proper return on equity is not a precise science; it is an exercise in informed judgment. Considering all the competing financial analysis evidence, we find that Dr. Wilson's traditional DCF approach, suggesting at the upper end an equity return of 10.4%, is about right. We note that an equity return between 10.0% and 10.5% falls within the range of equity awards in other jurisdictions and that such a check is useful in fulfilling the common sense approach NWIGU urges. While Dr. Wilson supports a lower number than what is represented by his high point, Mr. Hill points out that it is appropriate to consider that interest rates are rising and we can expect in such an environment some upper pressure on the cost of equity capital. Taking all into account, we find that PSE's cost of equity capital should be set at 10.3% for purposes of setting rates in this proceeding. Coupled with our determination to set PSE's equity share at 43.00%, the computed weighted average cost of equity is 4.43%. (Order No. 06, Docket Nos. UG-040640 and UE-040641, at p. 32 (¶ 80).)

37 (Emphasis added.) As noted above, the Puget order issuing in February of 2005, approved an ROE of 10.3%, and an equity component of 43%, resulting in an authorized weighted average cost of equity of 4.43%. This should be compared with the weighted cost of equity in Avista's proposed Settlement of 4.16% (40% common equity ratio; 10.4% return on equity). This is less than Puget's authorized cost of 4.43%, as discussed above. Moreover, it is less than Avista's recently completed, fully litigated combined electric and natural gas Idaho general case, where the weighted cost of equity was 4.43% (42.59% common equity ratio; 10.4% ROE). (Exh. 1, p. 14, ll. 3-10.)[7]

38 Furthermore, the allowed return on equity should reflect the evidence that interest rates will increase going forward. To begin with, Mr. Hill noted at page 25, lines 14-15 of his

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[7] Avista's Oregon weighted common equity is 4.95% (48.25% common equity ratio; 10.25% ROE), and PacifiCorp's recent settlement established a 4.75% weighted cost of equity in Oregon (47.5% common equity ratio; 10% ROE). (Exh. 1, p. 14, ll. 8-10.)

testimony (Exh. 261), that the "current expectation is that . . . interest rates will increase." As Dr. Avera also explained, capital market participants generally anticipate that "as economic growth strengthens, interest rates will begin to rise." (Exh. 62, p. 18, ll. 3-14.) On cross-examination, Dr. Avera provided updated information with respect to rising interest rates. He observed that long-term interest rates are higher than they were at the beginning of 2005.[8] Indeed, as of the day of his testimony on October 18, Dr. Avera noted that the producer price index went up 6.9%, which was the largest increase since 1990. (Tr., p. 387, ll. 11-15.) Moreover, he observed that Dr. Greenspan's address "the previous evening" had indicated concern about inflation and an intent to continue with "increases in the short-term rates of which there had been eleven so far, and there have been five since the beginning of the year." (Tr., p. 387, ll. 16-20.)

39 Turning to the risks of Avista specifically, Dr. Avera noted that Avista is "one of a small minority of utilities with a below investment grade credit rating," which implies a significantly higher risk and a higher required return on equity. (Id. at p. 6, ll. 4-26.) (Indeed, in response to questioning by Commissioner Jones, Dr. Avera noted that Avista is only among the seven or eight utilities below investment grade among the 130 major publicly-traded utilities. (Tr., p. 437, ll. 2-8.)) The fact remains that Avista's "BB+" rating only serves to

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[8] Dr. Avera went on to note that:

> The 60-day or 90-day Treasury Bill rate that Mr. Hill used is higher now than when he did his testimony. The 30-year Treasury Bond is considerably higher now than when he did his testimony. So interest rates have gone up since the first of the year and especially since the testimony before the Commission has been filed.

(Tr., p. 388, ll. 1-7.)

restrict the Company's financial flexibility and access to capital relative to other utilities. (Id.)[9]

40 Access to the capital markets going forward is important to Avista. In order to meet customer growth, provide for necessary maintenance and replacements of its systems and to fund new investment in electric generation, transmission and distribution facilities, Avista will need access to capital markets on reasonable terms.[10] It is, therefore, imperative that Avista return to investment grade so that it can attract capital on reasonable terms, thereby lowering costs for customers in the future.

41 Additionally, specific criticisms of the analyses done by Mr. Hill and Mr. Gorman are set forth in the rebuttal testimony of Dr. Avera (Exh. 62) and will not be repeated here.

C. The Equity Component of the Capital Structure.

42 Through the direct testimony of Company witness Malquist, the Company's original filing supported a capital structure with a common equity component of 44%. (See Exh. 31, pp. 24-29.) This equity component was derived from a proforma capital structure (as set forth

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[9] Avista is currently assigned a corporate credit rating of "BB+" by Standard & Poor's Corporation, with Avista's senior secured debt rating being "BBB-." Moody's Investors Service ("Moody's") has assigned an issuer credit rating of "Ba1" to Avista, while rating the Company's first mortgage bonds "Baa3." As testified to by Dr. Avera, "these corporate credit ratings place Avista in the same category as speculative, or 'junk' bond companies, with its senior debt ratings occupying the bottom rung on the ladder of the investment grade scale." (Exh. 50, p. 12, ll. 2-12.)

[10] To underscore this point, capital expenditures for 2005 alone will total $145 million, with approximately $275 million anticipated over the 2005-2006 period. (Exh. 50, p. 12, ll. 19-p. 13, ll. 13.) Looking over a longer time horizon, according to Avista's Integrated Resource Plan, the Company has identified the potential need to finance total expenditures for electric facilities of approximately $725 million over the next 10 years. (Id.) Not only will Avista be funding investment in utility infrastructure, it will also be required to refinance a significant portion of its long-term debt. As noted by Dr. Avera, the Company has securities of $71 million that mature in 2005-2006; over 50% of Avista's total debt (nearly $500 million) matures in 2007 and 2008.

in Exh. 32) which reflected expected changes based on average of quarter-ending information for the period December 31, 2005, through December 31, 2006. The proposed equity component of the capital structure was well-supported by the average capitalization for Dr. Avera's proxy group, which ranged from 39.1% to 65.8% - and averaged 51.1% (adjusted to 48.5% to incorporate short-term debt comparable to Avista). (See Exh. 50, p. 29, ll. 12-14.)[11] Accordingly, Avista's 44% common equity ratio, as originally proposed, fell well below the 48.5% average for Dr. Avera's proxy group.

43 Simply put, the agreed-upon equity component of the capital structure of 40%, as set forth in the Settlement, is conservative for the reasons discussed above. By way of further comparison, it is also well below the 43% common equity ratio approved recently for Puget in the above-referenced case. It is also well below the 42.59% common equity ratio determined to be appropriate in Avista's recently completed Idaho general rate case, as well as the Company's 48.25% common equity ratio currently in effect in Oregon. (Exh. 1, p. 14, ll. 5-10.)

44 It is well to note, however, that neither Public Counsel nor ICNU take issue with the 40% equity ratio incorporated in the Settlement Agreement. Indeed, Mr. Hill acknowledges that the 40% equity ratio is below the 43% equity ratio contained <u>within his own</u> proxy group, attesting to greater financial risk for Avista. (Tr., p. 787, ll. 21-p. 788, ll. 5.) Likewise, Mr.

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[11] As further support, Dr. Avera made reference to the Value Line Investment Survey, which anticipated that average common equity ratios for the proxy group of western utilities would increase to 56.3% over the next three to five years (or 53.4%, after incorporating short-term debt comparable to Avista). (<u>Id.</u> at p. 31, ll. 1-7.) In fact, in this Commission's February 18, 2005, order for Puget, <u>supra</u>, the Commission remarked that "[i]t is appropriate . . . to afford more weight to forward considerations than to historical conditions as we determine the appropriate equity ratio to be embedded in prospective rates." (Order No. 06, <u>supra</u>, at p. 32.)

Gorman's proxy group also demonstrated an average equity ratio of 43% - again well above the 40% set forth in the Settlement. (See Exh. 334.)

45 Mr. Hill, on behalf of Public Counsel, however, derived a "utility-only" capitalization. According to his arithmetic, he concluded that Avista's jurisdictional utility operations were actually financed with only 29.26% common equity. (Exh. 261.) Mr. Hill's analysis, however, does not represent a meaningful benchmark for purposes of evaluating an appropriate capital structure, for reasons explained by Dr. Avera:

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> Avista does not have a holding company structure. Consequently, a separate balance sheet is not reported for Avista's utility activities, with the capital for its various business lines being provided from general corporate funds. Moreover, investors can only purchase the debt and common stock of Avista, and their assessment of investment risks and required rates of return is driven solely by Avista's consolidated financial leverage, not a theoretical capitalization derived by apportioning capital sources among various utility and non-utility operating divisions.

47 (Exh. 62, p. 56, ll. 8-15.)

48 Dr. Avera further explained why ratepayers get the benefit of a consolidated capital structure, both in terms of the security that it provides for the bonds, and also the benefit of diversification that comes from having other businesses. (Tr., p. 423, ll. 3-15.) He noted that the energy marketing affiliate of Avista (Avista Energy) had been a "source of significant cash over the last several years." (Id.) Dr. Avera also noted ratepayers get the benefit of diversification when Avista has to go to the capital markets to raise money or to refinance its debt, "because of the corporate structure that creates financial resilience." (Tr., p. 424, ll. 19-24.)

49 Mr. Malquist also commented on the fact that, notwithstanding Avista Energy, Avista Corporation is in essentially the same "business position 6" as the proxy groups used by Mr. Gorman and Mr. Hill. (Tr., p. 484, ll. 18-p. 485, ll. 7.) Mr. Malquist went on to note,

however, that rating agencies take into account the risks associated with Avista Energy, as does the investment community. (Tr., p. 486, ll. 15-20.) As Mr. Malquist observed:

50 In the comparable groups we see a number of utilities with similar business positions as us, and that suggests to me that we have done a good job of mitigating the risks associated with Avista Energy since we're placed in essentially the same comparable groups as these other utilities are.

51 (Tr., p. 486, ll. 21-25.)

52 ICNU witness, Mr. Gorman, asserts that Avista should be required to suspend its common dividend payments until the Company reaches a certain utility-only common equity level. (Exh. 331, p. 5.) This, of course, would send precisely the wrong message to the financial community, at a time when the Company is trying to attract capital on reasonable terms. Dr. Avera did not spare words in describing the likely investor reaction:

53 Given investors' perceptions regarding the risks of electric utilities and the importance of regulatory support, slashing or eliminating dividends would undoubtedly be perceived as an unexpected and extremely negative, development by the capital markets. Considering investors' heightened sensitivity, this would represent a dramatic increase in investment risk and likely be interpreted as an unfavorable signal regarding Avista's future prospects. The collapse in the Company's stock price that would certainly result from such an unexpected shift in dividend policy would severely hamper Avista's efforts to strengthen its finances. A regulatory mandate to eliminate common dividend payments, as Mr. Gorman seems to advocate, would likely be perceived by investors as a draconian and punitive measure that would only serve to undermine efforts to enhance Avista's financial integrity and ongoing access to capital.

54 (Emphasis supplied.) (Exh. 62, p. 71, ll. 19-p. 72, ll. 10.)

55 It is important to maintain investor confidence, in order to gain access to capital on reasonable terms, especially during times of capital market adversity and financial stress. In

short, the elimination of dividends would "all but eliminate the company's financial flexibility," according to Dr. Avera. (Id. at p. 73, ll. 14-15.)[12]

56 In the Settlement, the Company did agree, however, to an "Equity Building Mechanism." Under the Settlement, the Company has agreed that it will increase the actual utility equity component to 35% by December 31, 2007, and to 38% by December 31, 2008. As explained in the Joint Testimony, the increase in the Company's utility equity component is expected to occur through growth in retained earnings and reductions in outstanding levels of long-term debt. (Exh. 1, p. 12, ll. 14-19.) According to the Equity Building Mechanism, failure to meet the common equity ratio targets in 2007 and 2008 would result in automatic reductions in base utility rates of 1%, effective April 1, 2008, and/or 1% effective April 1, 2009. Accordingly, there are sufficient penalties set forth in the mechanism in order to ensure the Company meets the common equity targets. As noted in the Joint Testimony in support of the Settlement, however, other "components" of the Settlement are also important in order for the Company to meet the higher equity component:

> 57 Important components of Avista's joint plan include the approval of the Settlement Agreement, progress in recovery of the power cost deferral balance of approximately $100 million, and a continuation of the ERM with a reduced deadband of $3 million. Without these important components, it would be difficult for the Company to make meaningful progress in reaching a higher equity component.

58 (Emphasis added.) (Exh. 1, p. 20, ll. 10-14.)

59 Finally, Mr. Gorman's suggestion that the amortization of the ERM deferral balance should be increased by an additional $12.4 million to reflect the difference between the

[12] In one well-publicized instance, Consolidated Edison Company's stock value dropped from $18.00 to $8.00 within two weeks of omitting its second quarter dividend in 1974. (Exh. 62, p. 72, ll. 15-16.)

Settlement revenue requirement and the lower cost using a 9.8% common equity return and Avista's actual common equity ratio, should be rejected outright. (See Exh. 344, p. 6, ll. 15-19.) Adoption of Mr. Gorman's proposal would reduce the agreed-upon revenue requirement of $22 million, as set forth in the Settlement, by an additional $12 million — essentially cutting in half the agreed-upon increase in base rates. The reaction of the investment community would be predictable, and the Company would be deprived of the earnings improvement necessary to help restore its financial well-being. That is not the way to return to investment grade status.

D. A Reduction in the ERM Deadband is an Essential Element of the Settlement.

60 The Settlement provides that the $9 million "deadband" would be reduced to $3 million, upon the effective date of the Settlement. (See Exh. 2, ¶ 13.) It is important to understand, at the outset, why a deadband was established at the $9 million level in the first place. As explained in the Joint Testimony, the deadband, itself, was developed in connection with a prior settlement that addressed some fixed-price contracts that were entered into by Avista during the 2001 energy crisis, in order to provide natural gas for thermal generation. (Exh. 1, p. 26, ll. 1-8.) In arriving at a deadband of $9 million, it was understood that a deadband at this level would cause the Company to absorb a portion of the cost of those natural gas contracts, whose price, at the time, was higher than the forward price of natural gas. (Id.) (The last of these natural gas contracts terminated on October 31, 2004.) (Id.)

61 It should be recognized that the Company has already absorbed $22.5 million in losses through the deadband since it was implemented in July of 2002. (Exh. 1 at p. 27, ll. 3-7.) In addition, another $5.7 million was absorbed by the Company through the 90/10 sharing

mechanism. Moreover, the Company anticipates that it will again absorb the entire $9 million deadband in 2005, given current hydroelectric conditions and natural gas pricing. (Id.)

62 The Company had originally proposed, in its filing in this case, to entirely eliminate the deadband. The Settlement, however, was a negotiated resolution of this issue, and served to reduce the deadband from $9 million to $3 million. As explained in the Joint Testimony:

> 63 This reduction provides a better balancing of costs that are not within the Company's control. It also recognizes the Company's experience to date with respect to the deadband as described above and reflects a compromise of the parties' litigation positions.

64 (Id. at p. 27, ll. 19-22.)

65 The Power Cost Adjustment (PCA) mechanism of the Company that is currently in place in the State of Idaho does not provide for a deadband, even though it is almost identical, in all other respects, to the ERM. This PCA, like the ERM, does, however, provide for a 90/10 sharing of changes in power supply costs – i.e., 90% of the changes in power supply costs are deferred for later rebate or surcharge to customers. (Id. at p. 27, ll. 10-13.) This 90/10 sharing mechanism, in effect in both Washington and Idaho, in their respective ERM and PCA mechanisms, provides sufficient incentive for the Company to do what it can to manage costs.

66 The financial community also views the "deadband" as problematic, subjecting Avista to greater earnings volatility than occurs with similar mechanisms. Excerpted in the rebuttal testimony of Mr. Norwood, is the Banc of America Securities Report of March 2005 ("The Kaleidoscope of Power Regulation in Focus"), wherein it provides its assessment of adjustment clauses in the State of Washington:

> 67 Adjustment Clauses – Fuel and purchase-adjustments are permitted, and Puget and Avista have adjustment clauses in place. The current plans subject the utility to the risks/reward of under/over collection of a portion of the change

in expected costs before costs are passed on to customers. This "dead band" approach has subjected the utilities to greater earnings volatility than a simple recovery mechanism.

68 (Emphasis added.) (Exh. 11, p. 15, ll. 12-18.).

69 Both Public Counsel and ICNU express a concern that a reduction in the deadband will shift the risk from the Company to customers. In fact, Avista already bears more risk than other utilities, inasmuch as their mechanisms do not include a sizeable deadband. Stated differently, the "elimination of the deadband would place Avista in a more comparable position with other utilities regarding the risk that it bears," according to Mr. Norwood. (Exh. 11, p. 15, ll. 25-27.) Conversely, the ROE for Avista should be much higher than other utilities, if the deadband is not reduced, since Avista bears more risk through a less-effective cost recovery mechanism. (Id.)[13]

70 Because Avista will be facing significant capital requirements in the future in order to invest in necessary infrastructure to serve its customers, it is important that both the deadband be reduced to no more than $3 million and that the ROE, as set forth in the Settlement, be approved. Both are key indicators to the investment community and will assist the Company in its efforts to attract capital on reasonable terms.

71 In its testimony, Public Counsel witness Lott discusses a number of suggested refinements to the ERM, such as the inclusion of transmission revenues and expenses, brokering fees, etc. (See Exh. 281, pp. 74-78.) It should be recalled that many of the items

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[13] It should also be recalled that the ERM, itself, even without a deadband, does not guarantee the recovery of even 90% of the power costs (with the other 10% being automatically absorbed by the Company). The Company is still required to make annual filings under the ERM, together with documentation that supports the additions to the deferral balance. This triggers further review and analysis by Staff and interested parties. Therefore, in addition to absorbing the first $9 million of cost increases, the ERM does not insulate Avista from the risk of the ongoing potential for regulatory disallowances.

discussed by Mr. Lott were considered during the original development of the ERM in Washington and the PCA in Idaho but, as noted by Mr. Norwood, were relatively small compared to other cost categories; moreover, there was a desire to "preserve as much simplicity as possible in the design of the mechanism." (Exh. 11, p. 17, ll. 10-17.) Nevertheless, as part of the Settlement, Avista has agreed that it will initiate discussions among all interested stakeholders concerning possible changes to the ERM, prior to January 31, 2006. (See Exh. 2, ¶ 13(C).) This forum would be more appropriate to further discuss those refinements alluded to by Mr. Lott in his testimony. In the meantime, however, the ERM mechanism is working well, but for the deadband.

72 It should be recalled that the ERM has been in place since July of 2002 and, as noted above, the Company makes annual filings with the Commission that provide the opportunity review the costs. Likewise, in the State of Idaho, the Company's PCA has been in place for over 15 years, and has been refined and improved over time. As noted by Mr. Norwood, the current PCA in Idaho is "essentially identical to the existing ERM, with the exception of the deadband." (Id. at p. 17, ll. 4-5.) There is, therefore, a "proven track record," with respect to both the ERM and the PCA. (Id.)

73 By way of summary, the ERM mechanism, itself, is well-suited for the recovery of costs over which the Company has little opportunity to control. These costs are driven, in large part, by prevailing water conditions affecting hydroelectric output, and the pricing of natural gas to fuel the thermal plants. The deadband feature of the ERM, however, has subjected the Company, over time, to greater earnings volatility than would a simple recovery mechanism. The investment community recognizes this shortcoming of the ERM and would view the reduction of the deadband as evidence of strong regulatory support for the Company in its effort to regain an investment-grade credit rating.

E. Boulder Park.

74 Public Counsel, through Mr. Lott, proposes a disallowance for the Company's investment in the Boulder Park project. Mr. Lott's recommendation is based entirely on a disallowance calculation of the Idaho Commission in Avista's last general rate case (Docket No. AVU-E-04-1), decided in October 2004; he provided no independent analysis of prudence related to his proposed rate base reduction of $4.4 million. (Exh. 281, p. 28, ll. 1-5.) In doing so, Mr. Lott has "cherry-picked" an item from the Company's recent Idaho rate case order. (Interestingly enough, Public Counsel did not choose to "cherry-pick" and adopt the 10.4% ROE or 42.59% equity ratio that were also contained within that same Order.)

75 More to the point, however, the Boulder Park project was previously reviewed as part of this Company's last general rate case before the WUTC that concluded in June of 2002, through a Settlement Agreement that was entered into by all parties, including Public Counsel. The Commission, when approving the Settlement Agreement, expressly noted that Staff had examined the costs associated with new power projects, including Boulder Park, and had found that these new projects were "prudently acquired." The excerpted language of that order, as set forth in Mr. Norwood's rebuttal testimony at page 13, is also reproduced here for ease of reference:

76 Staff also addresses new power supply costs, the prudence of which was reserved as an issue for the general rate proceeding. *Exhibit No. 14 (Staff Memorandum) at 15-20.* These costs include those associated with the Company's fifty-percent ownership in the Coyote Springs II generation project, its Boulder Park project, and the Kettle Falls CT generation project. 'Staff believes [these projects] will provide benefits in the form of firm energy supply and a reduction in exposure to the more volatile wholesale markets.' *Exhibit No. 14 (Staff Memorandum) at 15.* Staff states that based on its

> analysis, 'these projects were prudently acquired and that the Company should be allowed to recover associated costs, including capital costs, interest, depreciation and non-fuel O&M costs on a prospective basis. Id. at 15-16. Docket No. UE-011595, Fifth Supplemental Order, dated June 18, 2002, p. 11. (Emphasis added.)

77 The prudence of Boulder Park, therefore, has been addressed in the Company's prior Settlement. Beyond a selective reliance on the Idaho Order, Public Counsel has developed no other evidentiary record in this case that would support a different result.

F. Contested Power Supply Adjustments.

1. Production Property Adjustment.

78 In his testimony, Public Counsel witness Lott includes a "production property adjustment," which has the effect of reducing rate base by $15.2 million. (Exh. 281, pp. 22-24.) (See also Exh. 283.) Mr. Norwood, in his rebuttal testimony, made it clear that the costs that Mr. Lott was intending to address with his "production property adjustment" are already being adjusted for through the existing ERM calculations. (Exh. 11, pp. 7-11.) As explained by Mr. Norwood, the concern being addressed by Mr. Lott (and in the Retail Revenue Credit in the ERM), is that production property costs consisting generally of costs associated with owning and operating Avista's generating projects will be over-collected by the Company as retail loads continue to grow.

79 As noted by Mr. Norwood, in his rebuttal testimony, Public Counsel witness Lott would be correct, were there not "clearly an offsetting adjustment." (Id. at p. 9, ll. 1-2.) And that adjustment is referred to as the Retail Revenue Credit which is built into the existing Energy Recovery Mechanism. This is designed to address the "very issue" that Mr. Lott has raised in his adjustment. Mr. Norwood provided a simple example to illustrate how the Retail Revenue Credit (RRC) ensures that the Company does not over-collect production costs.

(This illustration assumes that new rates are approved effective January 1, 2006, based on 2004 loads.)

> 80 In the RRC calculation for January 2006, the actual retail loads (sales) for January 2006 are compared with the retail loads from January 2004 that were used to set base retail rates. If the January 2006 loads are higher than January 2004 loads, the increased kWh sales are multiplied by the cost of production, and the resulting dollar amount is credited back to customers in the ERM. This credit reduces the cost of power charged to retail customers, and ensures that Avista does not over-collect its production costs due to growth in retail loads. This adjustment occurs every month in the ERM.

81 (Exh. 11, p. 9, ll. 10-16.) Upon questioning by Chairman Sidran, Staff witness Parvinen also agreed that the so-called production credit <u>is already factored</u> into the ERM.

> 82 Q [Chairman Sidran]: Well, let me try reframing it. Do you agree or disagree with Mr. Norwood's testimony, which is I take it to the effect that the production credit is already factored into the ERM and that it would be <u>in effect double counting</u> if you were to follow the suggested raised by Public Counsel that it be done in the rate base?
>
> 83 A: Yes, yes I would agree with that.

84 (Emphasis added.) (Tr., p. 199, ll. 24-p. 200, ll. 5.)[14]

85 Moreover, the Retail Revenue Credit for 2003 and 2004 is working as planned and has resulted in sizeable adjustments in connection with the ERM. The Retail Revenue Credit for 2003 was $2.1 million and for 2004 was $3.7 million. (Exh. 11. at p. 10, ll. 7-12.) As pointed out by Mr. Norwood, the average of these two years is $2.9 million, which actually <u>exceeds</u> the $2.4 million adjustment to revenue requirement proposed by Mr. Lott through his production property adjustment. Stated differently, the Retail Revenue Credit production cost

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[14] Moreover, the Retail Revenue Credit under the ERM is based on <u>actual</u> load growth over time, instead of the load growth <u>estimates</u> that Mr. Lott proposes to be used in his adjustments. Accordingly, the Retail Revenue Credit adjustment that exists in the ERM provides a more accurate calculation of the production cost adjustment. (See also, Exh. 186, p. 19.)

adjustment already in place in the ERM, on an actual basis, has been greater than the adjustment proposed by Mr. Lott. (Id.)

2. The Purpose and Significance of the AURORA Model.

86 Because many of ICNU witness Falkenberg's adjustments rely on his understanding of the AURORA model, it is important to begin with a common understanding of the model. As explained by Company witness Kalich, the purpose of any power supply dispatch model is to reasonably determine expected operational and market conditions of the Company during the proforma period. (Exh. 174, pp. 2-3.) The Company employed the AURORA model for purposes of this filing, but it is important to note that the model, itself, was developed only after significant review by Avista, as well as the respective staffs of the Washington and Idaho Commissions, and members of the Company's Integrated Resource Plan Technical Advisory Committee. As such, the model has also been extensively used for purposes of the Company's 2003 and 2005 Integrated Resources Planning processes.[15]

87 For purposes of this case, it is well to recognize that the Commission Staff has been trained on this model several times since 2002 and possesses fully licensed versions of the software. For its part, Staff witness McIntosh described how Staff utilized the AURORA model in this proceeding, by "replicate[ing] the results" and by doing both "fuel and water sensitivities." (Tr., p. 204, ll. 21-25.)

88 A solid understanding of the AURORA model and its various assumptions is critical for purposes of analyzing costs and suggesting adjustments. The extensive use of the model

[15] Mr. Falkenberg acknowledged that the AURORA model was used extensively in the Northwest by clients such as BPA and several Northwest utilities; indeed, Puget has made use of the model in the last two of its rate cases, as well as in its last two PCORC filings. (Tr., p. 664, ll. 4-19.)

by the Company, Staff and others in the region has been discussed above. At the time of hearing, it was revealed, however, that ICNU witness Falkenberg is only newly-acquainted with this model. Notwithstanding the use of the AURORA model in the region for several years, Mr. Falkenberg admitted that he did not receive training on the model until July of this year — and that training only occurred approximately a month to a month and a half before he filed his testimony. (Tr., p. 665, ll. 3-14.) Moreover, he conceded that he only received a total of approximately three to four hours worth of training on the model and had no prior working experience with the AURORA model. (Tr., p. 665, ll. 15-22.) As will be further developed below, Mr. Falkenberg has made several errors in his use of the model, and his adjustments should be rejected.

3. Hydro-Normalization (Use of Number of Water Years).

89 In its audit of the Company's adjustments, the Staff utilized a hydro-normalization methodology based on the average of 50 separate simulations run through the AURORA model utilizing hydrological data for 50 years, from 1928-1979. The parties to the Settlement agreed to use this methodology for purposes of the Settlement. As will be discussed below, the Settlement was meant to employ the same methodology that Staff advocated in the recent Puget Sound Energy rate case (UG-040640/UE-040641) and that was adopted by the Commission in its order in that proceeding. [Even though the Settlement was meant to capture Staff's use of 50 years of water data (as opposed to the Company's original proposal to use a 60 year period), the resulting agreed-upon revenue requirement of $22.1 million does not, in fact, reflect the use of 50 years' worth of water data. This inadvertent omission, if corrected, would translate into a further reduction in revenue requirement of $165,000. (Tr.,

p. 552, ll. 2-3.) Avista would not object to this further revision, if so ordered by the Commission.]

90 To begin with, not only does ICNU witness Falkenberg use only a 40-year period (1939-1978), he then "filters out" approximately one-third of the water years based on a faulty statistical premise. As explained by Mr. Kalich, Mr. Falkenberg "skews the hydro data for the Company by 'cherry-picking' the better hydro years." (Exh. 174, p. 6, ll. 1-7.) Instead, one should begin with the generally-accepted premise that hydro data is normally distributed and exhibits no upward or downward trend. Mr. Falkenberg, however, eliminates all observations outside of "one standard deviation" which excludes a full third of the hydro years. (Id. at p. 4, ll. 8-16.) Accepted statistical theory, however, defines so-called "outliers" in normal and trendless distributions as those occurring beyond three or four standard deviations, not one, as explained by Mr. Kalich. (Id.). Illustration No. 1, as set forth at page 5 of Mr. Kalich's testimony, demonstrates that only one observation in the entire 60-year record exceeds even two standard deviations, and none exceed three or four standard deviations.

91 Even more telling is Mr. Falkenberg's selection of a 40-year hydro period (1939-1978), which serves to exclude lower stream flow periods. It should be remembered that the purpose of the hydro-normalization adjustment is to reset base utility rates in this case as close as possible to what historical evidence would dictate. If we fail, in that regard, subsequent adjustments through the ERM process will be even more sizeable, with the prospects for even greater deferral balances. Some care, therefore, should be taken to assure that we do not understate costs resulting from the hydro-normalization adjustment in setting base rates.[16]

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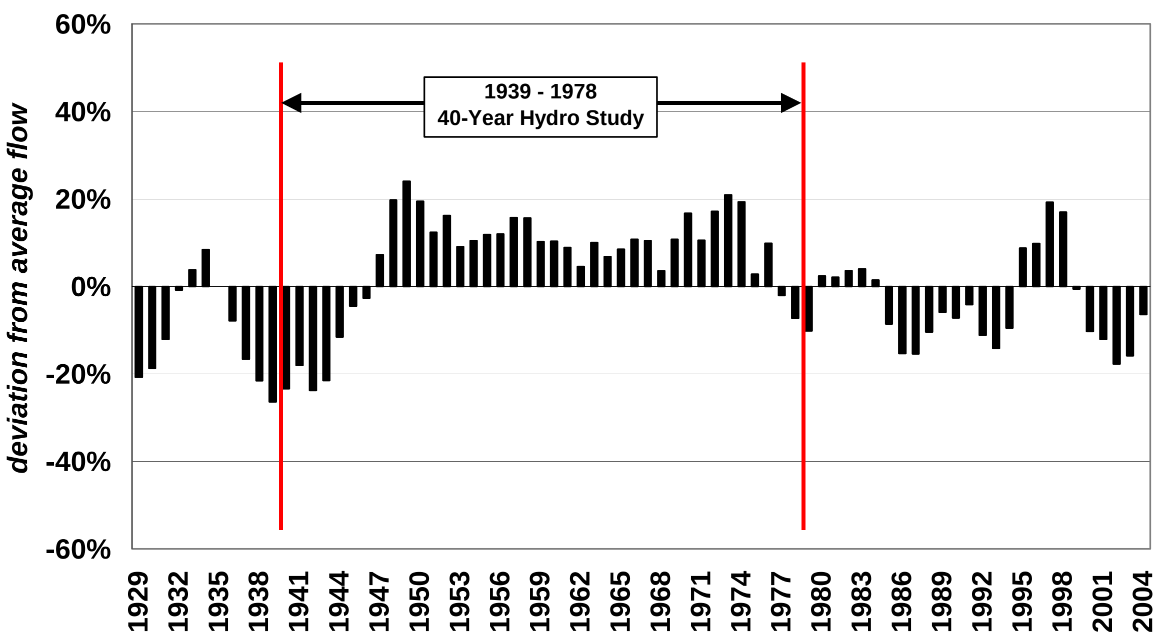
[16] Moreover, the Company, through the ERM mechanism, would continue to absorb $3 million under the deadband, and would still be subject to a 90/10 sharing on any additional dollars passed through the ERM.

92 Illustration No. 3, derived from page 8 of Mr. Kalich's testimony (Exh. 174) is set forth below in order to better illustrate the point that Mr. Falkenberg's approach selects a period of years that includes an extended number of above-average streamflows conditions:

Smoothed Historical Streamflow 1929-2004
Direct Deviation from 76-Year Average



93 A five-year average "smoothing routine" was applied to the 76 years of data in order to produce the illustration above. This is done simply for the purpose of smoothing out the year-to-year variations so that deviations from the average of multi-year periods are more easily seen, as explained by Mr. Kalich. (Exh. 174, p. 7, ll. 6-8.) As shown by this illustration, Mr. Falkenberg's use of a 40-year hydro study (1939-1978) clearly includes a disproportionate number of above-average years.[17]

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[17] In applying the AURORA model, Mr. Falkenberg also switched the 1973 and 1974 water years in deriving his hydro-normalization adjustment. Mr. Falkenberg acknowledged as much

94 Further demonstrating his biased results, Mr. Falkenberg was asked to read from his own sponsored Exhibit No. 304, consisting of a report entitled "Columbia River Flows and Droughts Since 1750." He agreed, on cross-examination, that his exhibit made reference to the drought of the 1930s, along with the observation that this should not be regarded as an "anomalous event," but is likely a typical fluctuation of the Columbia River system. (Tr., p. 669, ll. 3-p. 670, ll. 8.) Even so, in his own analysis, Mr. Falkenberg excluded the drought water years of the 1930s when he adopted, instead, a 40-year period of 1939 through 1978. Mr. Falkenberg next compounds the error by including a substantial portion of the water years 1950 through 1987 in his 40-year period [1939-1978], even though his own Exhibit 304 also characterizes these years as an "anomaly" – i.e., those years were characterized as having "no notable multiyear drought events." (See Tr., p. 671, ll. 1-20.) Simply put, his 40-year study both excludes the drought conditions of the 1930s and includes the "anomalous" period of 1950 to 1987 (containing "no notable multiyear drought conditions").

95 Finally, this Settlement which incorporates a hydro-normalization adjustment encompassing 50 years of data ending with 1978, comports with recent Commission precedent. Again, in the recently-completed Puget case, the Commission adopted Staff witness Mariam's recommendation for the use of a 50-year study. The Commission concluded as follows:

> 96 As the Commission's 1993 Order states, the basis upon which it found the 40-year rolling average to be superior to other approaches, was Staff's evidence in a prior case that the rolling average produced less cumulative error than other approaches. There is no evidence that Staff analyzed in those cases the statistical validity of the underlying stream-flow data as it did in this proceeding. We now have before us a detailed analysis, performed by Dr. Mariam, that confirms not only that the 50-year stream-flow data is trend-less

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during cross-examination. This mistake was corrected by Mr. Kalich in his rebuttal testimony appearing in Exh. 174, ll. 11-12.

> and normally distributed, but also that there is a high degree of correlation between stream flow and hydro generation. (Order No. 06, Docket Nos. UG-040640, UE-040641, at p. 50.) (Emphasis added.)

97 Therefore, this Settlement is aligned with recent Commission precedent and is supported by credible evidence in this record, as well, that 50 years worth of hydro data is appropriate for use in the hydro-normalization adjustment.[18]

98 Perhaps most telling, in the final analysis, is Mr. Falkenberg's own admission that his water year proposal "was not made on the basis of statistical analysis, but rather on the basis of policy considerations . . .." (Tr., p. 678, ll. 17-24.) On cross-examination, Mr. Falkenberg was asked about the statistical analysis performed by Staff (Dr. Mariam) in the recently-concluded Puget case; therein, the Commission commented, at paragraph 130 of the Order, that the "clear and convincing argument by Staff and PSE that the method presented by Dr. Mariam based on 50 years of data is a superior alternative to the 40 years rolling average." (Tr., p. 678, ll. 7-15.) The following exchange is revealing:

99 > Q: So you're bringing nothing new to this record in this case with respect to statistical analysis, correct?

100 > A: You know, after I read the Puget Sound order, I didn't feel that anybody could improve on the statistics that were presented in that case.

101 (Tr., p. 679, ll. 9-14.)

4. Hydro Shaping: Dispatch of Hydro to Meet System Loads.

102 Mr. Falkenberg, on behalf of ICNU, appears to define the optimal dispatch of hydro resources as that which establishes "a meaningful relationship between projected market prices and hydro operation." (Exh. 301C, p. 28, ll. 16-17). What he fails to recognize,

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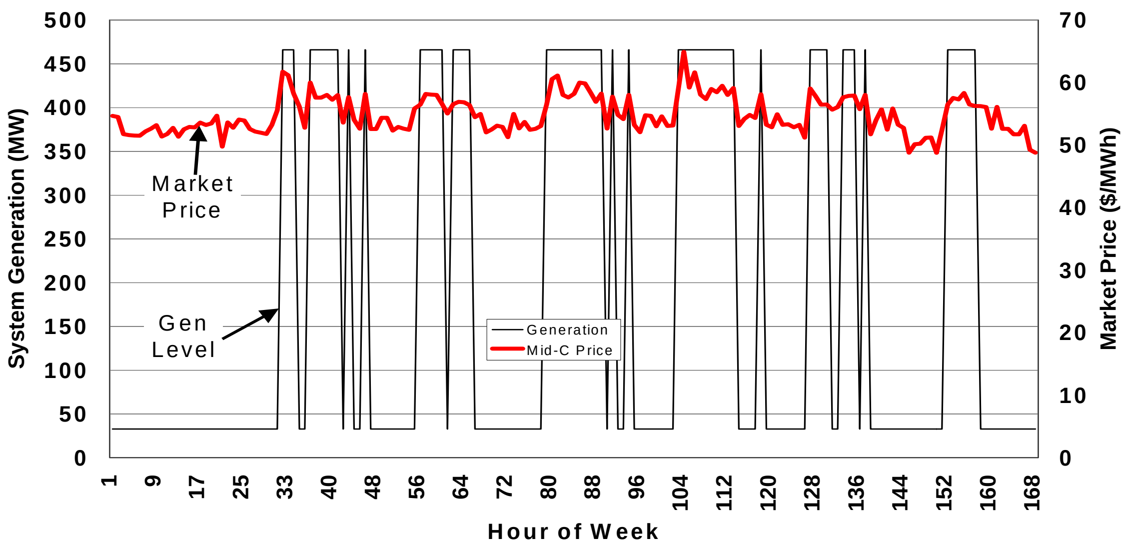
[18] Furthermore, it is important to note that in Avista's use of a 60-year water methodology for hydro normalization, in its original filing the Company did not pick the methodology with the "highest cost impact," as inferred by Public Counsel. (Tr., p. 574, ll. 20-24.)

however, is that many factors beyond market prices will affect the optimal dispatch of hydro resources. Company witness Kalich explains how the AURORA model dispatches discretionary hydro to "flatten the load requirement being served by other resources." (Id. at p. 13, ll. 4-14.) Mr. Kalich goes on to explain that Avista shapes its hydro generation to "peak shave," consistent with the AURORA model. He provided illustration No. 5, at page 14 of his rebuttal testimony to demonstrate how the AURORA model dispatched the Company's Clark Fork project against the Company's loads.

103 Mr. Kalich, at pages 15 through 17 of his rebuttal testimony (Exh. 171), also provides ten reasons why the Company does not generate at maximum capability each day with respect to its hydro projects. As he explains, factors such as unit outages, the need to maintain operating reserves, individual project characteristics, environmental restrictions, reservoir restrictions, and restrictions on transmission line capability are among the items that limit maximum generation at any particular time.

104 Mr. Falkenberg, in his analysis, vastly over-simplifies the modeling of hydro dispatch. He assumes only two levels of generation – minimum and maximum. Essentially, he either switches hydro "on" or "off." (Exh. 171, p. 18, ll. 1-7.) To illustrate how Mr. Falkenberg simply looks at the highest and lowest generation hours in each month, Mr. Kalich provided Illustration No. 6 in his rebuttal testimony, reproduced below:

January ICNU Hydro Modeling



105 This clearly illustrates the "on/off" character of his hydro modeling.

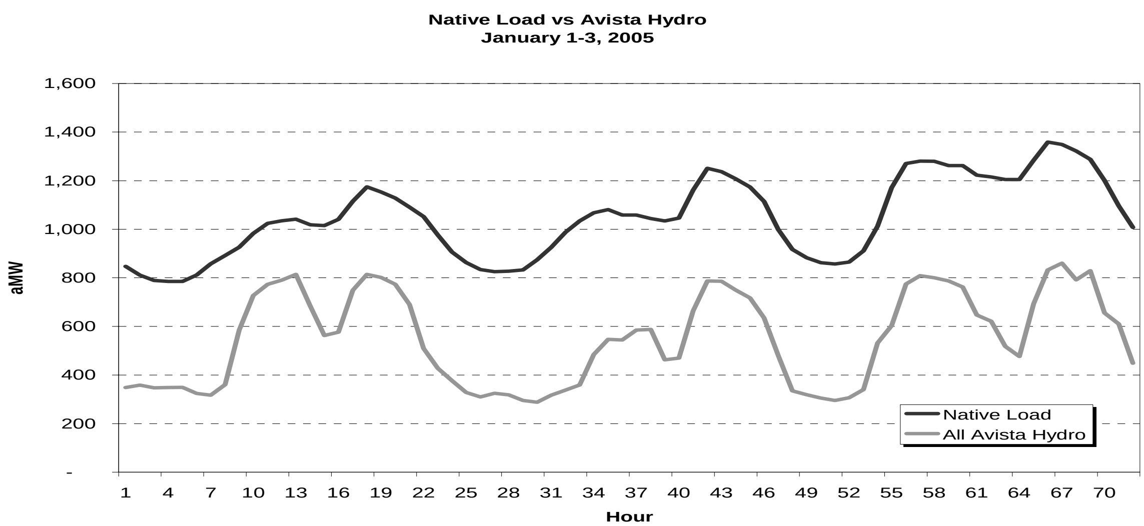
106 Mr. Falkenberg, however, attempted to further argue the point by introducing, during the course of the proceedings, Exhibit 323 illustrating how AURORA dispatches a <u>thermal</u> unit – CS II. In response to ICNU's testimony surrounding the operational characteristics of thermal plants (Exhibit 323), Mr. Norwood returned to the stand in order to explain the very fundamental differences between the operation of thermal and hydro facilities. With thermal plants, if the resources are needed to serve load or the market is such that it makes sense to run the project and sell it into the market, the plant will be operated, as explained by Mr. Norwood. Conversely, you will shut the plant down if you don't need it for load or to otherwise sell into the market. (<u>Id.</u>) As explained by Mr. Norwood, <u>hydro</u> represents a "very different situation":

107 > For hydro it's a very different situation. If you look at Exhibit 324, what this exhibit shows is actual loads. The top line is native load for three days, January 1st, 2nd and 3rd of this year, 2005. The bottom line shows how Avista actually ran its hydroelectric generation. What you see in that bottom line is the first two humps represents Avista ramping up its hydro resources during the morning peak, backing them off during the middle part of the day,

and then ramping them back up to meet the evening peak, and then going down again during the off-peak hours, middle of the night, back up again in the morning and afternoon, and you can see the third day that's there also.

108 (Tr., p. 767, ll. 9-24.) Mr. Norwood went on to explain why hydro facilities are run in that manner, in order to meet peak loads, throughout the day. Exhibit 324 is reproduced immediately below, and serves to contrast the actual operation of the Company's hydro system with what Mr. Falkenberg erroneously modeled, as was shown in the previous illustration:

[Exh. 324]



109 Finally, Mr. Norwood reiterated the ten factors that otherwise affect the operation of the hydro system, which further underscore the point that hydro plants are not operated in an "on/off" configuration as suggested by Mr. Falkenberg. (Tr., p. 768, ll. 13-25.)[19]

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[19] Accordingly, the Company properly shaped its hydro resources based on a 5-year historical shape, as explained by Mr. Kalich. (Exh. 171, p. 20, ll. 3-10.) This 5-year average is consistent with the period used for other modeling assumptions and is very consistent with the 10- and 15-year average shapes: the 5-year historical shape results in AURORA shaping 68.4% of the Company's hydro into more valuable on-peak periods. This is consistent with the 10-year on-peak generation average of 67.7% and the 15-year average of 68.1%. (Id. at p. 20, ll. 11-15.)

5. Colstrip Planned Outages.

110 Planned maintenance with respect to the Company's partial ownership of the Colstrip coal-fired plant has historically occurred from March through June in each year, with approximately 10% occurring in March and June and 40% occurring in the months of April and May. (Exh. 171, p. 21, ll. 11-19.) In its original filing, the Company had erroneously modeled Colstrip planned maintenance as occurring across all hours of the proforma year; this oversight was corrected during the settlement process, with the result of the Company decreasing its overall revenue requirement by $481,275, representing Washington's share of the adjustment. ICNU, through its witness Mr. Falkenberg, would nearly quadruple this adjustment to $1.643 million, by adjusting scheduled maintenance to simply coincide with periods of lowest wholesale prices. (See Exh. 301, pp. 35-38.) Mr. Falkenberg's analysis, however, clearly does not comport with actual historical schedules for required maintenance.

111 It is wrong to assume, as does Mr. Falkenberg, that all outages can be timed to occur during the least cost months of the year. Exhibit 176 provided confidential information with respect to the actual historical maintenance performed since 2003 with respect to Colstrip units 3 and 4, as well as planned maintenance for the years 2006 and 2007. For prior periods, it shows that the maintenance schedule does vary from year-to-year. It is simply not reasonable to assume, as does Mr. Falkenberg, that Colstrip maintenance is always timed to coincide with the period of lowest wholesale prices. As explained by Mr. Kalich, a number of factors influence the timing and maintenance, including the availability of labor to perform the maintenance, specific operating concerns at the individual plant, the extent of maintenance required, and market conditions. (Exh. 171, p. 21, ll. 8-10.) Market conditions, alone, however, do not – and cannot – dictate the timing of planned maintenance.

6. Bidding Factors.

112 Bidding factors are meant to more closely align forward natural gas market prices and wholesale electric prices, so that the Company's resources are operated, based on what we can anticipate in the 2006 marketplace. The use of bidding factors was included in the design of the AURORA model in order to better represent the forward marketplace. Mr. Falkenberg, however, argues that bidding factors should be eliminated in the power supply model. (Exh. 301C, p. 35.) Illustration No. 8, contained at page 24 of Mr. Kalich's rebuttal testimony (Exh. 171), demonstrates the impact of excluding bidding factors from the analysis. It clearly shows that, without the use of bidding factors, the AURORA model would not properly reflect the forward market. As such, the power supply model will not estimate proforma power supply expenses correctly.

113 Moreover, this Commission, in the recently completed Puget case, supra, recognized the importance of using forward prices, employing a 3-month averaging of forward market values. In its Puget Order, supra, at page 42, the Commission observed that ". . . we must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms." In this proceeding, the Settlement Agreement makes use of a 3-month average of forward natural gas prices, consistent with this Commission's recent order.

7. Fuel Price Adjustment for CS II/Hedging Practices.

114 The Settlement Agreement recognizes that natural gas prices have risen, and the futures and forwards market covering the rate year of 2006 has risen as well. (See Joint Testimony, Exh. 1, p. 19, ll. 17-p. 20, ll. 2.) Accordingly, the Settlement Agreement provides that the price of natural gas fuel should be set at $7.25/MMBTU, in order to better reflect

anticipated costs during the 2006 rate year. This figure was arrived at based on an average of the most recent 90 days of NYMEX futures, which the settling parties have agreed is a good indicator of the 2006 rate year's gas prices for rate-making purposes. (Id.) And, indeed, as noted above, the Commission's Order in the most recent Puget rate case, supra, made it clear that this method is currently acceptable in this jurisdiction.

115 Mr. Falkenberg, on behalf of ICNU, however, argues that the average price for all forward purchases is $6.85/MMBTU, relying on Exhibit 316 which was a worksheet previously prepared indicating the gas purchased, at that time, for electric generation for 2006. During the course of these proceedings, however, Company witness Peterson was asked to provide updated information with respect to the natural gas purchased for thermal generation. His Exhibit No. 204C demonstrated, that as of October 13, 2005, the average price of gas procured for thermal generation in 2006 was $7.34. Therefore, the $7.25 price embedded in the Settlement is conservative and may, if anything, understate the natural gas prices that will be experienced for purposes of fueling the Company's thermal generation during the rate year.

116 Mr. Peterson, on behalf of Avista, also described the Company's gas hedging strategy for Coyote Springs II, noting that the Company "looks out 18 months" and "layers in gas purchases" in accordance with its risk management guidelines:

117 Again, you have to think back to the way we manage our power positions, and it's not about speculating about gas prices and where gas prices are going to go, it's about managing open power positions and fueling the most economic resource for our customers at any point in time. Again, the way we do that is we look out to the future, we balance our loads versus our resources, and then we make a decision on whether we should buy fuel or buy power. We actually do hedge gas for Coyote Springs over time when it's economic to do so. We look out 18 months, and we layer in gas purchases when our risk management guidelines say that you have an open power position that needs to be filled. I think Mr. Norwood talked about that yesterday, but if you don't

> recall, we have actually hedged 40% of our gas needs for Coyote Springs through the end of 2006, and the average price that we have hedged is around $7.34.

118 (Emphasis added) (Tr., p. 594, ll. 11-p. 595, ll 2.) Mr. Peterson went on to explain that the remaining 60% of the gas needs for Coyote will not remain "unhedged" as we move into the upcoming year; rather, "between now and the time we get to running the plant in 2006, if it's economic, we will have hedged that gas." (Tr., p. 595, ll. 5-19.) Stated differently, if Coyote Springs II is economic to run, Mr. Peterson explained that "we would have purchased the gas ahead of time." (Id.)

119 Moreover, it is simply incorrect to assert, as does ICNU, that Avista is engaged in strictly a short-term purchasing strategy for gas. Company witness Peterson, at some length, described the Company's purchasing strategies, including hedging, for fueling its plants. Mr. Peterson explained that fuel for CS II is "hedged" before the time it is needed, as previously explained. Stated differently, the Company does not speculate on gas prices. Instead, the Company hedges gas as needed in order to meet load. Mr. Peterson commented on the fact that the $7.25 gas price in the Settlement was, if anything, conservative:

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> I would like to point out that in this particular case, we have agreed to a gas price of $7.25 in the settlement. As I had mentioned to you a moment ago, our hedges to date are at $7.34, forward gas prices for this winter are in the $12 to $13 range. The lowest prices that we see for 2006 are in the $9 range. And so I think the price that we have set in the Settlement is probably less than we're actually going to experience.

121 (Tr., p. 598, ll. 8-15.)

122 Nor will it do for ICNU to argue that the Commission's decision in Docket No. UE-031725 involving Puget and its Tenaska gas costs is pertinent. There, the Commission faulted Puget for using a strictly short-term purchasing strategy for gas, and for selling a long-term contract at a profit that was not returned to customers, while substituting gas at a later time at

much higher prices. In this case, Avista procures its natural gas supplies over the next 18 months, in keeping with its risk management policy. It is not simply procuring gas in the short-term market, whether defined as the day-ahead or month-ahead market.[20]

8. OASIS Transmission Revenues.

123 OASIS stands for "Open Access Same-Time Information System." It is a system used by transmission departments to schedule available transmission for other utilities and for independent generators. Revenues resulting from the sale of transmission capacity to third parties (OASIS revenues) are credited back to customers in this rate case, in order to offset a portion of the overall costs of transmission.

124 As explained by Company witness Cloward, in previous cases, the Company has used the most recent 5-year average as being representative of future expectations with respect to OASIS revenues. (See Exh. 221, p. 2, ll. 3-12.) The testimony of Mr. Cloward, however, makes it clear that "major changes" to the regional transmission system have caused OASIS revenues to be significantly different, going forward, than what has occurred in the past five years. (Id.) Originally, the Company had proposed OASIS revenues (system) in its filing of \$1.5 million; for settlement purposes, however, the Company has agreed to increase the OASIS revenues to be credited back to customers to \$2.4 million. (Id.) This should be contrasted with Public Counsel's position, which would credit \$3.2 million of revenues.

125 Mr. Cloward explains that OASIS revenue is generally dependent on energy market conditions, as well as Available Transmission Capability (ATC) on adjacent utility systems at

[20] The fact that its gas acquisitions extend out over the next 18 months is evident from the very exhibit on which ICNU relies (Exhibit 316) which shows not only the "trade date" but the "delivery month" as well. (See also Exh. 204C, showing the date purchased and the delivery dates for gas meant to fuel thermal generation.) These exhibits clearly demonstrate that the Company does not rely strictly on short-term gas purchasing to fuel its plans.

any given time. When examining market conditions in 2001, it is evident that Avista's OASIS revenues were nearly twice that of a typical year, due to the West Coast energy crisis observed during 2001.[21] Moreover, revenues of $5.4 million in 2004 are also not representative. During this period, as explained by Mr. Cloward, BPA was constructing a new 500 kV line from the Bell substation in Spokane to Grand Coulee Dam, as well as installing additional capacitor banks on four of its area 500 kV lines as part of the so-called "West of Hatwai Reinforcement Project." (Id. at p. 3, ll. 7-20.) These BPA transmission upgrades are now complete, however, and it has resulted in a substantial increase in BPA's ATC, well beyond levels available in prior years. As we go forward, this will "substantially reduce Avista's opportunity to sell transmission to third parties," as observed by Mr. Cloward. (Id. at p. 4, ll. 21-p. 5, ll. 3.) Accordingly, reliance on prior history is misplaced, in this instance, because the basic assumptions concerning available ATC have changed.

126 Given the new construction of BPA transmission and increases in BPA's available ATC, it is worthwhile to note the actual OASIS revenues for six months through June of 2005, which total $1.1 million. If one were to examine the percent of long-term and short-term transmission revenue received during the first six months of the year compared to the entire year, for the past several years (2001-2004), one finds that 45.75% of OASIS revenues are traditionally realized in the first six months of the year. (Exh. 221, p. 5, ll. 18-p. 6, ll. 2.) Therefore, if one were to use this percentage and annualize the current revenues through June of 2005, one would derive OASIS revenues for calendar year 2005 of $2.4 million. The

[21] As explained by Mr. Cloward, during that time, customers purchased almost all of Avista's ATC, which would allow those customers the flexibility to move energy from multiple locations based on the price and availability of energy. (Id. at p. 3, ll. 1-3.) Clearly 2001 was "an anomaly" and should not be used for future revenue forecasts, in this respect.

Settlement Agreement, itself, reflects this same $2.4 million amount. Mr. Lott's adjustment of $3.2 million, for the reasons stated above, is premised on operating conditions that existed prior to BPA's transmission upgrades, and is not representative of future conditions.[22]

9. Other Miscellaneous Power Supply Adjustments.

127 Public Counsel proposed twenty different miscellaneous power supply adjustments, while ICNU proposed two adjustments, one of which matched Public Counsel's. As discussed above, the Settlement, itself, incorporated twelve of the Public Counsel adjustments. Turning now to adjustments that were not incorporated in the Settlement, it was often the case that Public Counsel and ICNU, in their adjustments, reduced proforma 2006 expense levels below 2005 levels, or "known 2006 expense levels." This is a recurring theme and is discussed below.

(a) CS II Gas Transportation Expense Adjustment.

128 Avista pays a fixed gas transportation charge to transport gas from the AECO hub in Canada to Coyote Springs II. Mr. Lott, on behalf of Public Counsel, proposed to reduce these costs by $240,000 (system), based on prices using the then-current Canadian exchange rate. (See Exh. 281, p. 38, ll. 1-6.) The fact remains, however, that Mr. Lott's adjustment produces an annual expense in the 2006 proforma year that is lower than the expense that the Company is currently experiencing in 2005. (Exh. 186, p. 3, ll. 20-23.) In addition, Mr. Lott used an exchange rate of 79.35 U.S. cents/Canadian dollar while the average rate through July of 2005

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[22] Mr. Lott also makes a $48,000 downward adjustment pertaining to Colstrip O&M for the interconnecting 500 kV transmission line. (Exh. 281, p. 56, ll. 15-22.) Exhibit 294 provides updated 2006 O&M expenses for Avista's share of the 500 kV transmission system capital and expense budgets, as provided by Northwestern Energy, who manages the project. It indicates that Avista's share of the revised budget for 2006 is $340,906, which actually exceeds the level proformed into the Settlement.

has been 81.18 U.S. cents/Canadian dollar. The combination of Mr. Lott's adjustments results in proforma expense levels that are less than current 2005 expenses and should be rejected. (Id.)

(b) Kettle Falls Fuel Cost.

129 Here again, Mr. Lott makes an adjustment that is not reasonable because it is based on a fuel cost that is less than current 2005 costs; moreover, contracted-for costs in 2006 are known to be higher. (See Exh. 186, p. 1, ll. 23-25.) Mr. Lott proposed a unit fuel cost of $17.085/ton. This should be compared with actual 2005 costs through August of 2005 which have been $17.84/ton. (Id. at p. 4, ll. 17-22.) Moreover, the Company projects unit fuel costs to be $19.18/ton in 2006. (Id.)

130 Mr. Johnson, on behalf of the Company, explains why fuel costs at Kettle Falls are increasing. Approximately half of the Kettle Falls fuel cost is related to transportation. As the cost of diesel increases, the final delivered cost of fuel, therefore, correspondingly increases. Moreover, one of the larger fuel suppliers for Kettle Falls has a contract that ties the price that Avista pays to the price of natural gas. This was done because the supplier was using gas for their drying kilns and they had an option to switch over to burning their own hog fuel instead of using natural gas. Not surprisingly, the increase in the price of natural gas has driven up the fuel price from this supplier. (Id. at p. 5, ll. 7-12.)

(c) Wanapum Expense.

131 Avista purchases 8.2% of the output of Wanapum Dam, which is one of the dams on the Mid-Columbia owned by Grant County PUD. Avista pays fixed monthly payments, and in 2004, the total expense was $2,522,000 (system), which was projected to increase to $3,534,000 in 2006. Mr. Lott, however, arbitrarily reduces the proforma expense level by

$369,000 (system). Simply because the cost of Wanapum increased by 40% from the 2004 test year to the 2006 proforma year, is not, in and of itself, a sufficient basis for Public Counsel's adjustment. The Settlement is based on costs provided by the owner and operator of the project (Grant County PUD) which, as noted by Mr. Johnson, is "in the best position to establish the expected cost of the project in the proforma year." (Exh. 186, p. 10, ll. 19-21.) This is yet another example of an unsupported adjustment that results in a 2006 expense level that is lower than current levels.

(d) Rathdrum Lease Expense.

132 As explained in Mr. Johnson's testimony, the Company is terminating the Rathdrum lease. (Exh. 186, pp. 13-14.) Rathdrum is a two-unit simple cycle combustion turbine facility located in Rathdrum, Idaho, which was placed in service in 1995. At the time of construction, the units were financed through a lease arrangement and a lease expense was reflected for the pro forma year. (Id.) The Company, however, has recently announced its intent to "buy out" the Rathdrum turbine lease, believing that it would be less costly, in the long-term to do so, than to extend the financial arrangements under the lease.

133 While the costs associated with the buyout will be higher in the near term, in the long-term, the overall costs, on a present value basis, will be lower. (Id. at p. 14, ll. 3-7.) Accordingly, we already know that the known and measurable costs associated with buying-out the Rathdrum lease will be higher than that which is included in the Company's original filing in this case. Mr. Lott's adjustment will only serve to exacerbate the under-recovery of the revenue requirement associated with the buy-out of the Rathdrum lease. Simply put, given the buy-out of the lease, Avista's revenue requirement already is understated because it

was premised on lower near-term costs associated with the continuation of the lease arrangement.

(e) Short-Term Wheeling Expense.

134 Avista incurs a short-term wheeling expense in order to purchase additional transmission over and above its long-term firm transmission requirements. As explained by Mr. Johnson, short-term wheeling is typically used to move power from the Mid Columbia that is in excess of the Company's firm transmission rights between Mid Columbia and Avista's system. (Exh. 186, p. 6, ll. 3-6.) Mr. Lott, however, proposes an adjustment that significantly understates the short-term wheeling expense. In the 2004 test year, short-term wheeling expenses totaled $248,000 (system), and Mr. Lott would reduce that to only $54,000. (Id. at p. 6, ll. 9-13.) His adjusted level of expense is significantly lower than any of the previous five years, and is, as explained by Mr. Johnson, $294,000 less than the average of the past five years. (Id.)

135 Mr. Lott errs in mixing total system sales and purchases with short-term sales and purchases. He divides short-term wheeling expense by total system sales and purchase volumes to derive wheeling expense per unit of total sales and purchases. He then applies the per-unit expense to the proforma short-term purchases and sales volumes. In doing so, he arbitrarily "cuts in half the proforma wheeling expense." (Id. at p. 7, ll. 1-2.) Moreover, Mr. Lott does not recognize that actual short-term purchase and sales volumes always exceed modeled short-term purchase and sales volumes. (For the years 2000 through 2004, modeled volumes are only 21% of actual volumes.) (Id. at p. 7, ll. 3-10.) Therefore, Mr. Lott has failed to account for the fact that these modeled energy volumes generally represented only

1/5 to 1/3 of the actual volumes; this serves to understate, therefore, the proforma short-term wheeling expense.[23]

(f) Kaiser DES Revenue Adjustment.

136 DES stands for "Dynamic Energy Services." As explained by Mr. Johnson, Kaiser's Trentwood facility is "electronically" in Avista's control area, which means that the Company provides services that match their scheduled energy purchases with their load. For this service, the Company charges Kaiser a fixed fee based on their average load. Mr. Falkenberg, on behalf of ICNU, however, in his adjustment includes in the test year "deviation energy revenue," which represents energy that Avista sold to Kaiser as a result of scheduled energy being less than Kaiser's load. As explained by Mr. Johnson, however, this "deviation revenue" should not be included in the proforma because any revenue would exactly be offset by an equal expense related to the energy obligation, resulting in a net expense of zero. (Id. at p. 16, ll. 7-11.) In his adjustment, Mr. Falkenberg has included the revenue, but has excluded the expenses.

G. Other Contested Adjustments to Results of Operations.

137 What follows is a brief discussion with respect to each item, which will serve to explain why the adjustments proposed by Public Counsel and ICNU should not be accepted:

(1) Customer Deposits:

138 For its part, Public Counsel argues that Avista's rate base should be reduced by the average balance of customer deposits recorded during the test year. (See Exh. 231, pp. 11-

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[23] This Brief will not address the remaining miscellaneous power supply adjustments of Public Counsel, inasmuch as they are relatively small; the adjustment for "broker fees" and the "Garrison-Burke Wheeling Expense" account for only $18,000 and $16,000, respectively, at the NOI level. The Company's rebuttal to these adjustments appears at Exhibit 186, pp. 9-11.

13.) Mr. Dittmer is incorrect in his assumption that customer deposits should be viewed as a form of financing for the Company's utility operations, with a corresponding reduction in rate base. As explained by Mr. Falkner, customer deposits accrue interest at a short-term interest rate adjusted annually by this Commission. (Exh. 105, p. 5, ll. 12-18.) On the other hand, the Company looks to long-term financing, both debt and equity, in order to fund its utility operations. The entire amount of customer deposits is only $2.3 million, as contrasted with a Washington electric rate base level of approximately $800 million. (Id. at p. 6, ll. 1-9.) More importantly, it should be recognized that customer deposits are automatically returned to the customer after twelve months of payment history, as discussed by Mr. Falkner. (Id.) These deposits are simply a "tool for management of accounts receivable write-offs, not a financing vehicle, and are very short-term in nature," as testified to by Mr. Falkner. (Id. at p. 7, ll. 12-13.) They appropriately receive a short-term interest rate which is credited back to customers who have made the deposit.

(2) Kettle Falls:

139 Public Counsel's proposal regarding the treatment of the 1984 Kettle Falls disallowance should be rejected; this matter has been previously resolved in prior Commission orders and the Company's adjustment in this case is consistent with the treatment previously afforded Kettle Falls. By way of brief history, in Cause No. U-83-26, the Commission disallowed a portion of the Company's investment in the Kettle Falls generating plant; that decision was reaffirmed by the Commission in Cause No. U-84-28. Accordingly, in December of 1986, the Company recorded on its books a write-off for the amount of the Kettle Falls investment applicable to Washington operations that was previously disallowed.

(Exh. 105, p. 8, ll. 5-11.)[24] Nor was the Company's Kettle Falls adjustment contested in a subsequent proceeding, in Docket No. UE-011595; and, the Company's annual commission-basis reports have consistently reflected the Kettle Falls disallowance adjustment as filed by the Company in this case. (Id. at p. 9, ll. 16-21.)

140 Mr. Lott also argues that the 60.02% allocation factor is not appropriate for calculating the Kettle Falls disallowance. (Exh. 281, p. 13, ll. 1-8.) Mr. Lott contends that the Commission's previously ordered disallowance in Cause No. U-83-26 should somehow fluctuate each year depending on how the production/transmission allocation factor changes from year to year. (Id.) This would produce a non-sensical result. Instead of being a fixed, one-time write-off amount, Mr. Lott's suggestion would result in either "write-offs" or "write-ups" being recorded every year as the allocation factor changes. Accordingly, this would lead to the impossible situation where there never would be a "final resolution of this matter for financial reporting purposes," as observed by Mr. Falkner. (Exh. 105, p. 12, ll. 13-16.)

(3) Rate Base Adjustment for Coyote Springs II:

141 Public Counsel also proposes a reduction in rate base of $1,882,000, through the testimony of Mr. Lott, relating to Coyote Springs II. (See Exh. 281, pp. 20-21.) Public Counsel does not raise a "prudence issue with regard to this purchase." (Id. at p. 20.) It does, however, take issue with the manner in which the Company has pro-formed Coyote Springs into rate base, contending that the Company has over-stated the cost of this plant in the 2006 proforma. (Id.)

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[24] The Company recorded a $5,247,725 write-off on its books that reduced the investment level allocated to the State of Washington to 60.02% of $80,555,706, as provided for in Cause No. U-83-26. This write-off was pursuant to the Company's election, in 1986, to apply the requirements of Statement of Financial Accounting Standards No. 90, in reporting its 1986 results. (Exh. 105, p. 8, ll. 12-22.)

142 As explained by Mr. Falkner, in his rebuttal testimony, the Company's original proforma adjustments simply adjusted for the capital and associated O&M costs to reflect the most recent known and measurable information, consisting of 2005 information. As explained by Mr. Falkner, there are "no mismatches":

143 > The benefits of dispatching the second half of CS II have been captured in the power supply model, using 2004 loads, and the O&M costs have been included on a basis that is most consistent with the first half of CS II, calendar year 2005. What this does is eliminate the need to try to predict, or project two years out, what incremental additions and retirements are going to be incurred for CS II during 2005 and 2006, and produces a known and measurable result.

144 (Exh. 105, p. 15, ll. 4-9.) As such, the Company has appropriately pro-formed the incremental capital and associated O&M costs of the second half of CS II as a resource.

(4) Pro Forma Transmission:

145 Mr. Lott, on behalf of Public Counsel, proposes an adjustment that would reflect a pro forma transmission plant investment based on 2006 average of monthly average balances. (Exh. 281, p. 22, ll. 1-16.) His projection to the year 2006, however, should be rejected; instead, 2005 information should be utilized, which eliminates the need for additional projections of additions and retirements and produces an adjustment at a known and measurable level. 2005 is being utilized for the calculation, which will coincide with the date of completion, and its use will eliminate the need to speculate concerning future capital additions and retirements through 2006. (Exh. 105, p. 17, ll. 2-5.)

(5) California Sale Overhead:

146 Mr. Dittmer, on behalf of Public Counsel, argues for the reversal of the Company's electric and gas pro forma overhead cost adjustments related to the sale of its California gas properties in South Lake Tahoe, arguing that it is "not a certainty that 100% of corporate overhead costs will remain stable or 'fixed' following the property sale." (Exh. 231, p. 17, ll.

6-10.) When the Company began operating the California natural gas properties in 1991, the Company did not add any utility employees that would otherwise be considered corporate overhead, as explained by Company witness Falkner. (Exh. 105, p. 17, ll. 12-22.) The regulatory staffs of all four jurisdictions in which the Company operates reviewed and accepted a new common cost allocation methodology known as the 4-Factor. Accordingly, no Avista common costs had increased as a result of the acquisition of the properties and the existing common costs were then allocated to a much larger customer base that covered four jurisdictions (Oregon, California, Washington and Idaho), as opposed to only Washington and Idaho. (Id.) Therefore, what the Company proposes in this case is simply to reflect the sale of the California properties in accordance with a common cost allocation methodology that has been previously accepted and takes into account a known and measurable change to our customer base. (Id.)

(6) American Jobs Act of 2004:

147 Public Counsel, again through Mr. Dittmer, recommends that anticipated savings from the so-called "Americans Job Creation Act of 2004" should be incorporated into Avista's revenue requirement calculation in this case. (See Exh. 231, pp. 19-22.) This Act created a new deduction for qualified domestic production activities of U.S. business under Section 199 of the Internal Revenue Code, and includes electrical energy production within the definition of qualified production activities. While the Company believes that it may receive a tax benefit from the generation and sale of electricity under the provisions of Section 199 in the Act, the amount of any such tax benefit would be difficult to accurately estimate at the present time, due in large part to the fact that there is "minimal guidance presently available from the IRS" for how a utility would make the appropriate calculations. (Exh. 105, p. 20, ll. 1-5.) Indeed, Mr. Dittmer, in his own testimony, acknowledges that the Treasury Department has yet to issue its interpretive "regulations." (Exh. 231, p. 20, ll. 4-5.) The Company believes that this tax deduction should be reflected in future rate making when the Internal Revenue Service issues regulations that will make such an adjustment "measurable."[25] (Id. at p. 19, ll. 11-13.)

(7) Production Tax Credit:

148 Public Counsel, through Mr. Dittmer, argues that the entirety of the production tax credit associated with the operation of the Kettle Falls plant be used to offset the Company's electric revenue requirement, as contrasted with the 50% level originally proposed by the Company. (Exh. 231, pp. 22-25.) The Company had previously explained the justification for its proposal for a 50/50 sharing of the production tax credit between the Company and its customers, given its extensive participation in securing the tax credit as part of the 2004 Tax Act. (See Exh. 81, pp. 36-38.) Nevertheless, the Settlement includes all of the Production Tax Credit as a reduction in the revenue requirement.[26] If, however, this case were returned to a "contested" mode, the Company would argue for a 50/50 sharing, or in the very least that a 90/10 sharing of the tax credit, at a minimum, should be employed. (This would compare with the 90/10 cost recovery ordered by this Commission for the Company's investment in Kettle Falls in the Company's 1984 Rate Order. (Exh. 105, p. 21, ll. 17-21.))

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[25] Interestingly enough, the Company's first tax return to include this new tax deduction will not even be made until a year from now. (Id. at p. 20, ll. 22-23.) Nevertheless, for purposes of the Settlement, the parties did include an estimate of the benefit from the domestic production tax deduction, which was reflected as a reduction in the overall electric revenue requirement.

[26] Inasmuch as the Production Tax Credit varies with the amount of the generation output of Kettle Falls, any difference between the level that is approved in this case and the actual credits received in future periods would be tracked through the ERM mechanism. (Exh. 105, p. 22, ll. 8-9.)

(8) Vegetation Management:

149 Public Counsel recommends that Avista's pro forma "vegetation management" adjustment should be reversed. (See Exh. 231, pp. 26-32.) Mr. Dittmer asserts that this adjustment is simply designed to "catch up" on tree trimming maintenance that was previously deferred during the period 2001-2003. (Id. at p. 29, ll. 11-13.) The 2004 level however, was $2.3 million, and the Company's 2005 budget is $3.7 million, which is well above the test year level of expenditures. (Id.) The Settlement, however, should allay any concerns that the Company will not spend dollars set aside for tree trimming. The Settlement includes a "One-Way Balancing Account" which will track funds spent on vegetation management. As explained by Mr. Falkner, if dollars are not spent in any given year, the unspent balance will be accounted for and spent either in subsequent years, or otherwise credited back to customers. (Id. at p. 23, ll. 10-17.) (See also, Settlement at §10, p. 4.)

(9) Natural Gas Adjustments:

150 The contested adjustments, dealing with Customer Deposits and the California Sale Overhead, are identical to the adjustments discussed previously with respect to electric operations. As such, those arguments, outlined above, will not be repeated here.

H. Rate Spread/Rate Design.

151 Section 14 of the Settlement provides a detailed description of the spread of the proposed electric ($22,135,000) and natural gas ($968,000) revenue increases, as well as changes to the rates within the general service schedules. (See Exh. 2.) Page 1 of Attachment C to the Settlement shows the proposed increase to the Company's electric service schedules and page 2 shows the proposed rates within each of those schedules. Likewise, with respect to natural gas, page 3 of Attachment C shows the increase to natural gas service schedules, while page 4 shows the proposed rates within each of those schedules.

152 The Company used the results of its filed cost of service study as a "guide" in the spreading of the proposed increase by service schedule. As explained by Mr. Hirschkorn, in his direct testimony, the primary goal of the proposed rate spread is to move rates of return of the individual service schedules closer to the overall rate of return, so that all customers "contribute fairly to the cost of providing service." (Exh. 151, p. 9, ll. 14-21.) The relative rates of return for each service schedule, based on the Company's original revenue requirement and its cost of service study, are set forth below:

Relative Rates of Return by Service Schedule

	Before Increase	After Increase
Residential Service Schedule 1	0.61	0.75
General Service Schedules 11 & 12	1.91	1.60
Large General Service Schedules 21 & 22	1.53	1.35
Extra Large General Service Schedule 25	0.66	0.77
Pumping Service Schedules 31 & 32	1.06	1.04
Street & Area Lighting Schedules 41-48	1.14	1.10

153 (See Exh. 151, p. 10, ll. 1-9.) The Company, in its original filing, attempted to reduce the disparity between the relative rates of return by rate schedule by one-third in this proceeding, believing that this was a "reasonable balance between moving the rates toward the cost of service and other considerations, such as the overall level of the increase, and other proposed rate design changes," as testified to by Mr. Hirschkorn. (Exh. 151, p. 10, ll. 15-20.) The goal of moving each class at least one-third closer to unity is carried through to the Settlement.

154 The results of the Company's cost of service study demonstrate that rates for Residential Service Schedule 1 and Extra Large General Service Schedule 25, are below the cost of providing service, while the rates for General Service Schedule 11 and Large General Service Schedule 21 are above the cost of providing service. The rates for Pumping Service Schedule 31 and the Street and Area Lighting Schedules 41-48 are otherwise nearly equal to the cost of providing service. (See Exh. 1, p. 31, ll. 4-15.) Accordingly, the parties to the

Settlement agreed to spread the proposed increase ($22.1 million) by service schedule similar to the manner proposed by the Company in its direct filing. (Id.)

155 Mr. Lazar, on behalf of Public Counsel, however, suggests that the "peak credit assumptions" used by Puget, in its cost of service study may be more appropriate for Avista. (See Exh. 241.) The concept of "peak credit" serves to segregate production and transmission costs into demand and energy-related components. Avista, for its part, applies the peak credit concept differently than the process approved for Puget. Avista's cost of service study utilizes Company-specific peak credit assumptions and definition of peak hours, which caused its method to be different than the so-called "Puget Method." As Company witness Knox noted, this Commission has accepted Avista's departure from the Puget Method, when it noted in Avista's recent case that, "the Commission agrees that the usage patterns of each unique company are appropriately used in that company's cost of service study." (Third Supplemental Order, Docket No. UE-991606 and UG-991607, at p. 108.) (Exh. 136, p. 2, ll. 19-p. 3, ll. 2.)

156 As explained by Company witness Knox, the assumptions built into Puget's peak credit calculation were specific to Puget's Integrated Resource Plan in 1992, and embrace a 200-hour peak that is simply not relevant to Avista's system. As explained by Ms. Knox, the Company's use of peaking units is based upon the economic dispatch of its entire resource stack – that is, the Company incorporates all of the Company's production resources into the demand/energy comparisons. Moreover, the Company's demand allocation uses the average

of twelve monthly peaks (not the 200-hour peak) in order to capture customer contribution to peak throughout the year. (Id. at p. 3, ll. 4-13.)[27]

157 In the final analysis, however, irrespective of whether the Company's method or the so-called "Puget Method" are applied, the results remain essentially the same. At page 5 of her testimony, Company witness Knox set forth a table which demonstrates that the relative rates of return for each customer class are nearly identical. Therefore, the same customer classes, irrespective of the method used, still demonstrate the same under-recovery or over-recovery of the costs to serve them.

158 Turning now to matters of rate design, page 2 of Attachment C to the Settlement (Exh. 2) sets forth the electric rate design by schedule; likewise, page 4 of this Attachment does the same with respect to gas rates. Mr. Lazar, on behalf of Public Counsel, however, proposes that no increase be applied to the basic charge or to the first block rate in Residential Schedule 1, and that the entire increase be applied only to the second and third blocks. (Exh. 241.) Mr. Lazar's proposal wrongly assumes that lower cost hydroelectric resources should be used to serve the first 600 kWhs of residential customers' usage each month, and that higher cost thermal resources should be used to serve usage in excess of that amount. As explained by Mr. Hirschkorn, this proposal simply does not reflect the actual operation and dispatch of Avista's generating resources. (Exh. 159, p. 3, ll. 14-21.) Hydro generation has a

[27] Interestingly enough, as explained by Ms. Knox, the use of 200 peak hours for Avista's system would actually have the opposite effect on the demand allocation factors than may have been witnessed on Puget's system. The use of a 200-hour peak would focus all the hours during the extreme weather events, which would serve to increase the demand allocation to highly weather-sensitive customers like the residential class; high load factor customers would be allocated lower costs because their demand is less weather-sensitive. (Exh. 136, p. 3, ll. 4-13.) The advantage of using twelve monthly peaks is that it includes customer contribution to demand during extreme weather events as well as during more moderate times of the year, as explained by Company witness Knox.

significant amount of flexibility in order to serve variations in load. Accordingly, hydro generation is used to cover both seasonal and intra-day load variations, which would include a substantial amount of energy used to serve the second and third blocks of the Residential Schedule. (Id. at p. 4, ll. 1-7.) In contrast, the Company's base-load thermal resources are generally run "around the clock year-around as they are available." (Id.) It follows that thermal resources are actually used to serve a substantial portion of the first 600 kWhs used by residential customers, contrary to Mr. Lazar's belief. [28]

159 Finally, the Company disagrees with Mr. Lazar's assertion that there should be no increase in the residential basic charge. Mr. Lazar argues that the proposed rate increase is driven by thermal power costs, and that power costs are proportionate to usage and should be recovered in the usage rates. (See Exh. 241, p. 19, ll. 6-8.) This would be true if all of the proposed increase in this case represented an increase in variable costs, but, as explained by Mr. Hirschkorn, a significant portion of the increase represents an increase in fixed costs that do not vary with usage. (Exh. 159, p. 5, ll. 15-21.) Accordingly, the Company is proposing a proportionate increase in the basic charge to reflect the fact that the fixed costs of providing service are increasing as well.[29]

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[28] Furthermore, the current difference between the first and third block of Residential Schedule 1 is 1.645 cents/kWh, which differential is already greater than what cost of service would support. (Exh. 159, p. 4, ll. 11-15.)

[29] As recognized above, a significant portion of the proposed revenue increase reflected in this filing results from increases in fixed costs that do not vary with customer usage – i.e., additional investment in electric plant and increased operating costs to maintain reliability of service. Given the increase in fixed costs reflected in this filing, as well as the proposed increase of 8.9% to Residential Schedule 1, the Company believes that the 10% increase to the customer charge of $0.50 per month is reasonable. (See Exh. 151, p. 12, ll. 11-17.) Parenthetically, Puget Sound Energy's current residential customer charge was recently increased to $5.75 per month as part of the Commission's Order No. 6 in Docket No. UE-040641. (Exh. 151, p. 12, ll. 19-20.)

I. Low-Income Demand-Side Management and Rate Assistance Programs.

160 Under the Settlement, the Company will provide an additional $200,000 to fund low-income demand-side management, over and above the $900,000 per year presently provided for DSM funding. Also, the Company will provide an additional $600,000 per calendar year (for the next two years) for the Low-Income Rate Assistance Program (LIRAP), thereby increasing total funding to approximately $3.6 million per year. At the end of the two-year period, the Company will consider several factors regarding future funding levels which would include, but not be limited to, the need for and use of LIRAP funds, the continuation of the low-income tax credit, and the general level of the tariff rider. (See Exh. 1, p. 28, ll. 14-p. 29, ll. 9.) Additional DSM funding will be made available from a reallocation of existing Schedules 91 and 191 DSM funds, without otherwise increasing the Schedule 191 DSM fund.[30] The additional LIRAP funding is the result of a combination of tax credits and a reallocation of Schedule 191 natural gas DSM funds to LIRAP. (Id.)

161 In addition to increase funding levels, several programatic changes will be adopted to increase the administrative flexibility of low-income agencies in their operation of both the LIRAP and DSM programs. These are described in the Settlement at paragraph 15(B). (See Exh. 2.) Such changes include the ability to use funds generated by Schedule 91 for

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[30] In September of 2003, Avista received approval to nearly double its Schedule 191 rate to both maintain its gas DSM and to pay down the negative DSM deferral balance. (Tr., p. 330, ll. 1-5.) Moreover, as testified to by Mr. Hirschkorn, under the Company's current gas DSM programs, Avista has "exceeded its target by over three times" – i.e., this represents over 800,000 therms saved in the past year, as opposed to a target of just over 240,00 therms. (Tr., p. 330, ll. 11-17.)

combination electric and gas LIRAP customers, and a reallocation of funds within the LIRAP and DSM programs.[31]

162 The increase in funding for both the DSM and LIRAP programs, as well as enhanced programatic flexibility, further illustrate how the Settlement addresses a variety of issues beyond just revenue requirement. The Settlement, joined in by the low-income constituencies represented by the Energy Project, seeks to address increased funding requirements for low-income programs. The Company is mindful of the impact of any increase in rates, and has, through the Settlement, attempted to address these concerns in a balanced, reasonable manner.

V. CONCLUSION

163 The Settlement should be approved as offered. A settlement of an electric revenue requirement at $22.1 million and a natural gas settlement of $968,000, when compared with the supportable litigation positions of the Company, should be deemed reasonable.

164 Moreover, the process by which the Settlement was arrived at allowed for ample opportunity for discovery by all affected parties, as well as for several settlement sessions. Indeed, the final Settlement ultimately incorporated many of the issues raised by both Public Counsel and ICNU. Furthermore, the Settlement is supported by the record and prior Commission precedent, as demonstrated by the expert testimony presented by parties to the Settlement. In expert testimony, the Company explained why an ROE of not less than 10.4%, based on an equity capital structure of 40%, was, at a minimum, necessary for the Company to begin to regain its investment-grade rating. Also, the several power supply adjustments proffered by Public Counsel and ICNU simply do not withstand scrutiny. These include such

[31] These programatic changes will be subject to a cost-effectiveness review based on the "utility cost test" and a review by Avista's External Efficiency Board. (Exh. 1, p. 29, ll. 15-19.)

items as the Production Property Adjustment (already accounted for in the revenue credit mechanism built into the ERM), and the errors surrounding the selection of the hydro normalization period, and the hydro shaping adjustment. Numerous other contested adjustments to results of operations, beyond power supply, also suggest that the revenue requirement in this case, were it to be fully litigated, would, if anything, well exceed the agreed-upon revenue requirement in the Settlement.

165 Moreover, the importance of reducing the $9 million deadband to $3 million, as part of the Settlement, cannot be overstated. This is an integral part of the Settlement which, together with an appropriate return on equity, is key to restoring investor confidence in the Company.

166 Finally, it is well to reiterate why the Settlement is "in the public interest." It strikes a reasonable balance on the issues, and represents hard bargaining on a variety of what would otherwise be contested issues in a fully-litigated case. Acceptance of the Settlement by this Commission will enhance the Company's prospects for an improved credit rating. The Settlement was only arrived at after extensive discovery and reflects the give-and-take of any true settlement process. In the final analysis, it covers a broad spectrum of issues beyond revenue requirement. It should be viewed as a "package" that is supported by the record and is consistent with prior Commission precedent.

RESPECTFULLY SUBMITTED this 14th day of November, 2005.

AVISTA CORPORATION

By:________________________________
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