BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKET NO. UE-080416 and DOCKET NO. UG-080417
Complainant,	)	
vs.	)	
AVISTA CORPORATION, D/B/A AVISTA UTILITIES,	)	
Respondent.	)	

BRIEF OF AVISTA CORPORATION
(REDACTED)

REVISED 1/28/09

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1 COMES NOW, Avista Corporation (hereinafter "Avista" or the "Company"), 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 4, 2008, the Company filed proposed tariff revisions requesting that the Commission grant an electric rate increase of $36,617,000 or a 10.29% increase in base retail rates. The Company requested that the Commission grant an increase of $6,587,000 or a 3.33% increase for Avista's natural gas operations. The Company's request was based on a

proposed rate of return of 8.43% with a common equity ratio of 46.3% and a 10.8% return on equity.

3 The Company proposed to spread the requested electric revenue increase by rate schedule on a uniform percentage basis. The proposed natural gas increase by rate schedule, although not on a uniform basis, would result in rates of return for each schedule that are reasonably close to the cost of service study results (unity). The Company proposed to raise the electric and natural gas residential monthly basic charge to $5.75 from the current $5.50 charge.

4 On July 25, 2008, the Company filed supplemental evidence to reflect a revised electric service revenue requirement of $47.4 million based on updated accounting and financial data. (See Exh. EMA-4T) The Company, however, did not otherwise revise its tariff filing to reflect these changes. (See Exh. JT, p.6, l. 19 – p. 7, l. 11)

5 After a lengthy period of discovery and at the conclusion of several settlement conferences, a Multiparty Settlement Stipulation (hereinafter "Settlement") was reached and filed with the Commission on September 16, 2008. The process leading up to this Settlement will be discussed in more detail below. A copy of the Settlement was introduced as Exhibit 5 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 did not join in the Settlement and the Industrial Customers of Northwest Utilities ("ICNU") only joined in portions of it, as discussed further below.

6 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, 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."

7 The Commission, in this proceeding, is not required nor is it being asked to approve an alternative revenue requirement at this time, should the Settlement be rejected. WAC 480-07-750(2) provides that, if the Commission rejects a settlement, "the litigation returns to the status at the time the settlement was offered and the time for completion of the hearing will be extended by the elapsed time for consideration of the settlement."

8 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.) The Company originally filed for $36.6 million in increased electric rate relief and $6.6 million in increased natural gas revenues. 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 supplemental and rebuttal testimony. Simply put, the Settlement produces an "end result" that is in the "public interest" and will serve to provide much-needed improvement in the Company's financial condition. The joint testimony of the Stipulating Parties (Exh. 4T), as well as the testimony of various Company and Staff witnesses rebutting the arguments of Public Counsel and ICNU, provide strong support for the Settlement.

B. COMMISSION PRECEDENT REGARDING SETTLEMENTS.

9 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:

10 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.

11 (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. Accordingly, the Commission is obligated to balance both investor and consumer interests.[1]

12 As this Commission observed at page 27 of its Order No. 06 (Docket No. UE-032065), which approved a 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 Again, in its more recent order, dated October 8, 2008, approving the Settlement and Stipulation reached in the PacifiCorp rate case, this Commission reiterated the governing principles:

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[1] "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).

15 > . . . The parties made compromises relative to their respective litigation positions to arrive at end results that are fair, just and within an acceptable range of possible outcomes supported by the evidence in the record.

16 > While we acknowledge the opposition to any rate increase expressed by members of the public through oral and written comments, our decisions must be made in accordance with law, policy and the factual record before us. The Commission's mission is essentially one of determining an appropriate balance between the needs of the public to have safe and reliable electric service at reasonable rates and the financial ability of the utility to provide such services. Thus, the results of our orders in proceedings such as this must be to establish rates that are, in the words of our governing statutes, "fair, just, reasonable and sufficient."[2] This means rates that are fair to customers and to the Company's shareholders; just in the sense of being based solely on the record developed following principles of due process of law; reasonable in light of the range of possible outcomes supported by the evidence; and sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms. (Emphasis added)

17 Utilities and Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co., Docket UE-080220, Order 05 (October 8, 2008) at para. 31.

18 The Multiparty Settlement in this case satisfies those requirements, by finding "an appropriate balance" and produces an "end result" that is well within "an acceptable range of possible outcomes." Id. 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 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 reasonable." It is this "end result," which balances the interests of consumers and investors alike, that is the objective of this process.

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2 RCW 80.28.010(1) and 80.28.020.

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

19 More than sufficient time was allotted the parties for discovery and audit of the Company's books and records. The Company originally filed for rate relief on March 4, 2008, more than six 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 "litigation" positions. 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 culminating with the filing of the Settlement Agreement on September 16, 2008 — which was shortly before the September 19, 2008, pre-filing date for Staff and Intervenor testimony.

20 As described in the Joint Testimony supporting the Settlement (Exh. 4T, p.8, l. 21 – p.9, l. 16), all six parties to this case commenced discussions for purposes of resolving or narrowing the contested issues in this proceeding in a settlement conference held on August 20, 2008. Subsequently, the parties participated in telephonic Settlement Conferences on August 29, 2008, September 4, 2008, September 8, 2008, and September 9, 2008.

21 Extensive discussions occurred on the components of the Company's filing, including the cost of capital, and accounting and power supply adjustments. The parties engaged in the "give-and-take" that characterizes settlement discussions and attempted to arrive at a reasonable balance of differing interests. As is common in settlements, each of the Stipulating Parties ultimately agreed to concessions on matters which would not have been agreed to if each of the Stipulating Parties were to proceed to evidentiary hearings.

22 Settlement meetings were scheduled well in advance and significant discovery occurred in the months leading to the first Settlement Conference. The Company's responses to 450 data requests were provided to all parties who requested them. The final telephonic settlement conference of September 9th was within approximately two weeks of the September 19th due date of filing testimony by Staff and Intervenors, and therefore it was reasonable to expect discovery to have been substantially completed and the major issues already identified for purposes of settlement discussions.

23 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. SUMMARY OF ESSENTIAL TERMS OF THE SETTLEMENT

24 As summarized in the Joint Testimony (Exh. 4T, p.4, l. 9 – p.5, l. 11), as part of the Multiparty Settlement Stipulation, Avista's annual electric revenues would increase by $32.5 million, representing a $4.1 million reduction from the Company's original request of $36.6 million. Avista also agreed to an annual natural gas revenue increase of $4.8 million, a $1.8 million reduction from its original request of $6.6 million.

25 The overall increase in base electric rates would be 9.1 percent under the Settlement, down 1.2 percent from Avista's original request to increase base electric rates by 10.3 percent. Natural gas rates would increase overall by 2.4 percent with the Settlement, down 0.9 percent from Avista's original request to increase base natural gas rates by 3.3 percent.

26 The Multiparty Settlement Stipulation calls for an overall rate of return of 8.22 percent with a common equity ratio of 46.3 percent and a 10.2 percent return on equity.

27 The Multiparty Settlement Stipulation was signed by Avista, the WUTC Staff, NWIGU and the Energy Project. Public Counsel did not join in the Multiparty Settlement Stipulation. ICNU, while a signatory, only joined in the following portions of the Stipulation:

> 28 Power Supply-Related Adjustments (Section III. A. (a.)); Cost of Capital (Section III. A. (m.)); Rate Spread/Rate Design (Section III. B.); Low Income Bill Assistance Funding (Section III. C.); Demand Side Management (DSM) Expenditures (Section III. D.); and Prudency of Energy Efficiency Expenditures (Section III. E.).

29 The Stipulating Parties have requested implementation of the Multiparty Settlement Stipulation on January 1, 2009. This proposed effective date is an "integral" part of the Settlement and was one of the trade-offs among the concessions made on a variety of issues by the Stipulating Parties. (Exh. 4T at p.6, ll. 13-16)

30 The "Summary Table of Adjustments" for both the electric and natural gas revenue requirements that appear at pages 19 and 24 of the Joint Testimony in support of the Settlement are excerpted and attached as an appendix to this Brief. Pages 20 through 26 of the Joint Testimony discuss individual line items in these Summary Tables. As explained in the Joint Testimony (Exh. 4T, p.17, ll. 5-11):

> 31 While the line-item adjustments do have separate characteristics, they are being accepted only as part of a comprehensive Multiparty Settlement Stipulation that resolves all issues associated with the Company's original filing. As can be seen by a quick review of the individual line descriptions, the adjustments accepted for settlement purposes cover a broad range of revenue and cost categories, including the rate of return on investment. It would be inappropriate to view the individual adjustments in isolation. They should be viewed in total as part of the total Multiparty Settlement Stipulation.

32 Numerous components relating to the Power Supply Adjustment portion of the settlement were the result of extensive negotiations: These included a "<u>hydro filtering</u>" adjustment to remove months where hydro generation exceeded average generation for the month by more than one standard deviation; a "<u>WNP-3 Contract</u>" adjustment to include

energy purchased in 2007 in the 5-year average; a "fuel cost adjustment" to reflect a pro forma period natural gas price of $8.30/Dth for natural gas-fired generation for the unhedged portion of 2009 generation[3]; correction of a mathematical error in the calculation of Colstrip coal cost; and a Noxon Generation adjustment to properly match the capital investment in a plant upgrade with the resulting increase in generation. (See Exh. 4T, pp. 20-21) These elements were negotiated not only as a "package" of power-supply related adjustments, but also as part of a bigger package of all elements contained within the Settlement. All of these power supply adjustments are supported by, not only the Stipulating Parties, but also by ICNU. Furthermore, nowhere in Public Counsel's responsive testimony to the Company's original filing, supplemental filing and Settlement Agreement, do they propose specific changes to these power supply components.

33 Also included in the Settlement is the agreed-upon accounting treatment for certain costs associated with: (1) Spokane River Relicensing; (2) certain Confidential Litigation; and (3) the Montana Riverbed Litigation. Each of these are discussed immediately below.

34 The Company included in its filing the processing costs associated with its Spokane River relicensing efforts, which expenditures included actual life-to-date costs from April

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3 In response to questions from Commissioner Jones, Company Witnesses Norwood and Kalich explained that the figure of $8.30/Dth was arrived at as "part of the total package" through negotiation, after considering the merits of various approaches, including the use of averages; that it remains a reasonable estimation given the pricing volatility in the market (e.g., witnessing a recent increase of 75¢/Dth in just one week); that this agreed-upon fuel price only impacts the unhedged portion of the fuel supply for 2009, which is only approximately five percent (5%) of Avista's load obligations; and that it is not unlike the approach used in the recently-concluded Puget general rate case (Dkt. No. UE-072300) where the Commission approved, on October 8, 2008, a settlement that incorporated a fuel price of $8.51/Dth. (See Tr. pp.181-183; p.193) It should also be remembered that, to the extent natural gas prices were to fall below the agreed-upon level of $8.30/Dth, the revisions to the ERM as part of the Settlement would mean that customers would realize the benefit of 75% of the lower prices through the second tier of the deadband.

2001 through December 31, 2007, and 2008 pro forma expenditures through December 31, 2008. (See Exh. EMA-1TC, p.23) The Stipulating Parties have agreed that the costs were prudently incurred and have agreed, that once the Company receives the license, to defer as a regulatory asset (in Account 182.3 – Other Regulatory Assets) Washington's share of the depreciation/amortization associated with the aforementioned relicensing costs and related protection, mitigation, or enhancement expenditures, together with a carrying charge on the deferral, as well as a carrying charge on the amount of relicensing costs not yet included in rate base. It is important to note that the costs covered by the Settlement are only those costs presented by the Company in this case, where the parties had full opportunity to review such costs. Any costs that exceed the pro formed costs in this case would be addressed in a separate filing.

35 Company Witness Andrews describes the Confidential Litigation at pages 23 and 24 of her pre-filed direct testimony (unredacted) (Exh. EMA-1TC). The Stipulating Parties have agreed that the pro forma costs in this case are prudent and have agreed to defer as a regulatory asset (in Account 182.3 – Other Regulatory Assets) Washington's share of the depreciation/amortization associated with the aforementioned costs with a carrying charge on the deferral as well as a carrying charge on the amount of costs not yet included in rate base for subsequent recovery in rates. That deferral, of course, does not commence until the first payment is actually made under the settlement. Again, it is important to note that the costs covered by the Settlement are only those costs presented by the Company in this case, where the parties had full opportunity to review such costs. Any costs that exceed the pro formed costs in this case would be addressed in a separate filing.

36 Finally, on November 11, 2007, Avista filed an Application with the Commission (Docket No.UE-072131) requesting an accounting order authorizing deferral of settlement

lease payments and interest accruals relating to the recent settlement of a lawsuit in the State of Montana over the use of the riverbed related to the Company's ownership of the Noxon Rapids and Cabinet Gorge hydroelectric projects located on the Clark Fork River. The Commission, in its Order No. 01, previously authorized the deferral of settlement lease payments together with interest, at the weighted cost of debt, until the matter was addressed in this general rate filing. The Stipulating Parties have agreed to the Company's requested amortization of costs, together with recovery of accrued interest on the Washington share of deferrals at the weighted cost of debt, net of related deferred tax benefit.

37 The Stipulating Parties have also agreed to a modification to the existing Energy Recovery Mechanism to incorporate an element of asymmetry in the ERM by giving customers a greater share of the benefits when power expenses are lower than the authorized level. The adjustment changes the sharing level in the second ERM band ($4 million to $10 million) to 75% customer/25% Company when power supply expenses are lower (rebate direction), while maintaining the 50%/50% sharing in the second band when power supply expenses are higher (surcharge direction).

38 Finally, the Stipulating Parties and ICNU agree to adjust the LIRAP portion of the tariff riders (Schedules 91 and 191) to provide an increase in annual funding of $500,000. With this increase, the annual funding level for electric low income customers will be $2,864,000, and for natural gas customers will be $1,580,000.

39 Moreover, the Stipulating Parties and ICNU agree to increase low income DSM by $350,000 over and above the existing funding level of $1,132,000, and to adjust the Tariff Rider Adjustment Schedules (91 and 191) accordingly.

40 For purposes of program administration, the total funding level of $1,482,000 for low income DSM includes amounts that may be dedicated to energy-related health and safety

measures, the expenditures for which shall not exceed fifteen percent (15%) of overall actual low-income DSM expenditures. The Company and The Energy Project agree to work with participating low income agencies on the development of contract provisions to assure that the combined portfolio of electric and natural gas low-income DSM expenditures remain cost-effective.

41 As evidenced by the foregoing discussion, the Settlement addresses a broad spectrum of issues and represents a series of compromises that cut across this entire spectrum.

IV. THE SETTLEMENT IS "IN THE PUBLIC INTEREST"

42 In the final analysis, the Settlement represents a negotiated compromise among the Stipulating Parties. That is the nature of any settlement process. The Settlement is comprehensive and appropriately balances the competing interests of the parties and is in the public interest.

43 The Joint Testimony of the Stipulating Parties concluded with observations explaining why the Settlement was "in the public interest." (See Exh. 4T, pp. 9-15.) 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. Furthermore, the Settlement will assist the Company in regaining its financial strength and thereby improve the prospects for maintaining an investment-grade credit rating. In the Joint Testimony (Exh. 4T) at p. 10, l. 14 – p. 11, l. 3, Avista explained:

> 44 Although we are continuing to make progress in improving the Company's financial condition, as shown by the recent upgrades in the Company's corporate credit ratings to investment grade, we are still not as strong financially as we need to be and remain at the lowest rung of the investment grade credit rating scale (BBB- for Standard & Poor's and Baa2 for Moody's Investor Service). Timely rate relief through this filing is an important element in preserving our existing credit ratings, and having the opportunity to improve that rating. With higher levels of capital spending required over the next several years, it is more important than ever that the Company

> remain financially healthy in order to attract capital investment and financing under reasonable terms. The Company's initiatives to manage its operating costs and capital expenditures are an important part of improving financial strength, but are not sufficient without the Commission's approval of the agreed cost recovery and return opportunity and conditions provided under the Multiparty Settlement Stipulation.

45 Moreover, the filing has been subjected to extensive discovery, with the Company responding to over 450 data requests; for its part, Staff assigned several 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 multiple settlement conferences noted above.

46 Public Counsel/ICNU may argue that this Commission cannot – or should not – give any weight to the Supplemental Testimony filed in this by the Company, which would have justified an even higher revenue requirement of $47.4 million. This testimony served to "correct for" several errors[4] (four of the seven adjustments actually would serve to lower the revenue requirement) and to update the power supply expenses. (See EMA-4T) This Commission has previously expressed its interest in having current information available, in order to base its discussions on "a full and adequate record." (See Order 04, in this docket, dated August 8, 2008; also, WUTC v. Puget Sound Energy, Inc., Dkt. No(s). UE-072300 and UG-072301, Order 08, at para. 10.)

47 It should be remembered that any settlement process involving rate case litigation routinely corrects for known errors and takes into account more recent information. That is nothing new. The important point is that, even if the Company hadn't filed Supplemental

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4 Each of these errors was ultimately corrected for in the Settlement itself.

Testimony in this docket, the settling parties would have, in any event, attempted to correct for these known errors and to take into account more recent information with respect to power supply costs, as explained by Company Witness Andrews. (Tr. p.263, l. 10 – p.264, l. 1)

48 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. As explained in the Joint Testimony (Exh. 4T) at p. 10, ll. 3-8:

> 49 For example, from Avista's point of view, it does not reflect any adjustment for union wage increases that we know will occur in 2009. Nor does the agreed-upon revenue increase cover the significant capital additions that will occur in 2009. As such, the Settlement, even if approved, will not fully address increasing costs during the 2009 rate year and represents, if anything, <u>a conservative portrayal of Avista's need for rate relief</u>. (Emphasis added.)

50 This Settlement, as presented, produces an "end result" or outcome that is squarely in the "public interest." Moreover, the Settlement addresses a <u>broad</u> spectrum of issues, not just revenue requirements. As earlier noted, it provides for increased funding for low-income DSM and LIRAP programs, it provides increased benefits to customers through certain modifications to the ERM, and addresses a number of issues pertaining to relicensing and litigation. As such, the Settlement represents a "package" of different components and should be viewed as a whole.

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

A. OVERVIEW OF PUBLIC COUNSEL/ICNU LITIGATION POSITION AS IT RELATES TO THE SETTLEMENT.

51 Public Counsel/ICNU presented two witnesses, who provided direct testimony as well as testimony in response to the settlement: Mr. Charles King proposed depreciation rates and expenses that substantially differed from those embodied in the Settlement; Mr. Michael Majoros, for his part, addressed other revenue requirement issues, including a number of Administrative and General (A&G) expense items. As a result, Public Counsel/ICNU initially

argued for an electric revenue requirement increase of $20.118 million, as compared with Avista's original request of $36.617 million (or $47.4 million as justified in Avista's Supplemental Testimony). (See Exh. MJM-4C) By way of further comparison, the agreed-upon revenue requirement increase in the Settlement is $32.5 million.

52 Moreover, with respect to a natural gas revenue requirement increase, Public Counsel/ICNU initially recommended an increase of $0.627 million, as compared with the Company's original request of $6.587 million; the Settlement, itself, reflects increased revenue requirement of $4.8 million. (See Exh. MJM-4C)

53 Subsequently, at time of hearing, Public Counsel/ICNU acknowledged a computational error in their derivation of their proposed Federal Income Tax (FIT) adjustment, and revised their exhibits to reflect a proposed electric revenue requirement increase of $24,477,000 and an increase in the natural gas revenue requirement of $3,341,000. (See MJM-9C, pp.1-2) On November 21, 2008, Public Counsel/ICNU further revised their electric revenue requirement to $24,841,000 and its gas revenue requirement to $3,471,000, reflecting corrections to Mr. King's depreciation calculation. (See Revised Exhibit MJM-9)

54 For its part, Avista presented rebuttal testimony, challenging the various adjustments proposed by Public Counsel/ICNU. Company Witness Falkner addressed the FIT adjustment proposed by Public Counsel/ICNU, demonstrating that the initial calculation was simply inaccurate, that it violated jurisdictional cost allocation principles and quite possibly the Internal Revenue Code's normalization provisions. (See Exh(s). DMF-1T and DMF-2.) Company Witness Andrews addressed a number of individual revenue requirement adjustments proposed by Public Counsel/ICNU which would have materially impacted the electric and natural gas revenue requirements, including, e.g., items such as compensation,

and D&O insurance, etc. (Exh. EMA-7T) Mr. Spanos, on behalf of the Company, provided rebuttal with respect to proposed changes in depreciation rates, supporting the traditional method of accounting for net salvage accrual, in order to properly match recovery of service value across generations of ratepayers. (Exh. JJS-1T) Mr. Felsenthal, on behalf of the Company, testified that the commonly-accepted straight-line method for accounting for the "cost of removal" as a component of annual depreciation rates remains appropriate, as opposed to a "sinking fund approach"; he also explained why any accumulated cost of removal obligation is not otherwise available to offset other costs, such as the Confidential Litigation settlement costs in this proceeding. (Exh(s). ADF-1T and ADF-2) For her part, Company Witness Pessemier, provided testimony regarding the Confidential Litigation adjustment. (See Exh. TEP-4TC)

55 At the outset, and in order to put the litigation positions of Public Counsel/ICNU into perspective vis-à-vis the Settlement, Company Witness Mr. Norwood, on behalf of the Company, presented testimony demonstrating that, by simply correcting for certain computational errors in their initially proposed FIT adjustment, recognizing the uncontested power supply adjustments, and reaffirming that traditional use of straight-line depreciation, the electric revenue requirement of Public Counsel/ICNU, "would actually exceed that which is contained within the Multiparty Settlement Stipulation." (Exh. KON-1T at p.1, ll. 10-14) First, drawing from Mr. Falkner's testimony that the proposed FIT adjustment was not only based on faulty reasoning but was largely driven by simple computational errors, Mr. Norwood testified that even simply correcting for the computational error in this adjustment would serve to increase Public Counsel/ICNU's initial electric revenue requirement by $4.4 million and the natural gas proposed revenue requirement by $2.7

million. (Exh. KON-1T, p.2, ll. 5-19) As discussed above, Public Counsel/ICNU did, in fact, correct for these errors at the time of hearing. (See MJM-9C) (MJM-ITC)

56 Moreover, as noted earlier Public Counsel did not sponsor expert testimony addressing any of the power supply adjustments that were included within the Multiparty Settlement, which totalled $7.4 million. (See Settlement, §III, Part A) In fact, ICNU expressly supports the Settlement with respect to a number of items, including the net power supply adjustments of $7.4 million. (See §II, ¶4 of Settlement; Exh. 5) As explained by Mr. Norwood, by incorporating only the two adjustments discussed above, i.e., the removal of the FIT error (acknowledged by Public Counsel/ICNU) and the inclusion of the net power supply adjustments, Public Counsel/ICNU's recommended electric revenue increase level would move to $31.2 million – which is only $647,000 less than the revenue requirement of $32.5 million set forth in the Settlement Agreement itself. (See Exh. KON-1T, p.3, ll. 7-16) Of course, this is without any consideration of the Company's extensive rebuttal with respect to a variety of other adjustments proposed by Public Counsel/ICNU that were, themselves, not reasonable.

57 Finally, for purposes of providing additional perspective, Mr. Norwood addressed the revenue requirement impact of rejecting Public Counsel/ICNU's proposal for a "sinking fund" type methodology for net salvage value, insofar as it otherwise "represents a significant departure from the long-standing depreciation practices in this and nearly every other jurisdiction." (Id. at p.3, ll. 19-22) As stated differently, were this Commission to simply reaffirm existing, straight-line depreciation practice, the recommended revenue requirement of Public Counsel/ICNU would increase by an additional $3.3 million for electric service and $1.3 million for natural gas service. (Id. at p.3, ll. 22 – p.4, l. 1)

58 The following table is excerpted from the rebuttal testimony of Mr. Norwood and serves to isolate the impact on the revenue requirement of simply adjusting for these three issues alone – even without addressing the remaining revenue requirement issues raised by Public Counsel/ICNU:

Table 1: Impact on Revenue Requirement of Certain Adjustments

	Impact on Revenue Requirement	
(Dollars are in thousands)	**Electric**	**Natural Gas**
Correct for FIT Computational Error (& resulting conversion factor flow through impact)	$ 4,358	$ 2,714
Net Power Supply Adjustments Agreed to in Multiparty Settlement (and endorsed by ICNU)	7,433	-
Reaffirm Straight-line Depreciation (Re: cost of removal)	3,057	1,197
Total	$ 14,848	$ 3,911
Public Counsel/ICNU [Initially] Recommended Revenue Requirement	20,118	627
Addition of above 3 items to Recommended Rev. Req. of PC/ICNU	**$ 34,966**	**$ 4,538**
Revenue Requirement agreed to in Multiparty Settlement	**$ 32,538**	**$ 4,768**

59 (See Exh. KON-1T, p.4) This table makes the simple, if not obvious, point that by merely correcting for the acknowledged computational errors in the FIT adjustment, otherwise removing the unsupported depreciation adjustment for "cost of removal," and simply recognizing the uncontroverted net power supply adjustments in the Settlement, Public Counsel/ICNU's revenue requirement would increase to $35.0 million for electric service – an amount that is well above the $32.6 million revenue requirement set forth in the Settlement. Even without further discussion of the other revenue requirement adjustments, this attests to the reasonableness of the Settlement, and, as explained by Mr. Norwood demonstrates that

"the 'end result' of the Settlement falls well within the zone of reasonableness." (Id. at p.5, ll. 3-8)

60 Avista did not stop there, however, and did in fact challenge through rebuttal testimony each of the more significant of the remaining adjustments proposed by Public Counsel/ICNU, most of which pertain to Administrative and General (A&G) costs.[5] Those items will be discussed below. Nevertheless, as a further "reality check" attesting to the reasonableness of the Settlement itself, it should be noted that the Settlement removes a total of $1,852,000 of electric A&G expenses, which is within $44,000 of the total of all of Public Counsel/ICNU's A&G adjustments ($1,896,000). (Id. at p.5, ll. 12-15) Stated differently, the Stipulating Parties' settlement position is nearly identical to Public Counsel/ICNU's litigation position, with respect to the total of all A&G adjustments. Much the same could be said with respect to the resolution of all the natural gas A&G issues. "This further attests to the reasonableness of the 'end result' reached with respect to all electric A&G issues in the settlement" as explained by Mr. Norwood. (Id. at p.5, ll. 15-16)

B. PUBLIC COUNSEL/ICNU'S FEDERAL INCOME TAX ADJUSTMENT WAS FRAUGHT WITH COMPUTATIONAL AND CONCEPTUAL ERRORS.

1. Public Counsel/ICNU's Original Adjustment Contained Significant Computational Errors, Before Being Corrected

61 For purposes of his adjustment, Mr. Majoros, on behalf of Public Counsel/ICNU, initially changed the Company's tax rate from the federal statutory rate of 35.0% to an "effective federal tax rate" of 31.0%. (See Exh. MJM-1TC, pp. 11-14/Exh. MJM-6) The initial revenue requirement impact of his adjustment was $5,563,000 for electric service and

[5] Were this Settlement rejected and this matter to revert to litigation, Avista, of course, would address the remaining miscellaneous items (e.g., dues/donations, etc.), but which do not otherwise materially impact the revenue requirement.

$3,488,000 for natural gas service. The Company presented the rebuttal testimony of Mr. Falkner, who is the Assistant Treasurer and Tax Director of the Company (see Exh. DMF-1T), who explained why Mr. Majoros' calculation was, in the first instance, inaccurate and otherwise conceptually flawed. In addition to violating jurisdictional cost allocation principles, it may also violate the "normalization" provisions of the Internal Revenue Code, and is a concept that has been previously rejected by this Commission, as well as FERC. (Id. at p.2, ll. 3-9)

62 Mr. Falkner began by explaining how Avista reports for income tax purposes. The consolidated Avista Corporation group files one consolidated tax return with the IRS; even so, the IRS requires that actual taxable income be computed "for each legal entity on a separate company basis," as explained by Mr. Falkner. The statutory rate, however, for both Avista Utilities, on a stand-alone basis, and for the consolidated group of Avista companies is 35%. (Id. at p.4, ll. 1-2)

63 Nevertheless, Mr. Majoros initially used what he characterized as an "effective tax rate" of 31%, arguing for a "consolidated tax adjustment" by which the taxes of the regulated utility are reduced by a portion of the tax benefits generated by tax losses, if any, of non-regulated affiliates. In so doing, he allocated a portion of the tax losses of any non-regulated subsidiaries to the Utility, based on the Utility's ratio of its positive taxable income to the sum of the positive taxable income of all consolidated entities. More specifically, he isolated those non-regulated subsidiaries that had incurred losses during 2005 and 2006 (tax years for which information was then available) and then allocated what he characterized as the "utility portion" of those losses to Avista's tax expense for each of those years. In this manner, he arrived at what he termed an "effective tax rate" for each year, which was then averaged for

2005 and 2006 in order to arrive at an average rate for his 2007 adjustment. (Id. at p.4, ll. 16-21)

64 Even if one were to accept this concept, he initially did it wrong, before correcting for the computational errors at time of hearing. That is to say, he incorrectly applied the full pre-tax impact of those non-regulated subsidiary losses as a reduction to the utility's tax expense, rather than the tax effect of the losses. As explained by Mr. Falkner, by "incorrectly applying the entire pre-tax losses, and not the tax impact of the losses, to Avista's tax expense is a fundamental error and creates a serious understatement of his so-called 'effective tax rate' of 31% . . ..." (Id. at p.5, ll. 3-7) By correcting for this simple computational error, the resulting two year average "effective tax rate" would become 34.0% - not 31%. (This is demonstrated in Mr. Falkner's Exh. DMF-2.)

65 That is, however, not the only computational error originally made by Mr. Majoros. In addition to failing to calculate the tax impact of the pre-tax loss incurred by subsidiaries, as discussed above, he then failed to calculate the appropriate jurisdictional allocation of the tax impact in order to arrive at Washington's jurisdictional share of the loss. (See Exh. DMF-1T, p.5, ll. 18-22)

66 After correcting for these computational errors, as was done by Public Counsel/ICNU at time of hearing, the corrected electric FIT adjustment would be a reduction to the revenue requirement of $1.205 million – which is $4.358 million less than the original adjustment proposed by Mr. Majoros. (See MJM-4C) Similarly, the corrected natural gas FIT adjustment would be a reduction to the revenue requirement of $0.774 million, which is $2.714 million less than the original adjustment proposed by him. (Exh. DMF-1T, p.6, ll. 1-8) As will be discussed below, however, the Company does not support even the remaining portion of these adjustments, believing them to be deeply flawed conceptually.

67 Finally, while the 2007 consolidated Federal Income Tax return was not available to Mr. Majoros at the time he prepared his adjustment utilizing 2005 and 2006 returns, it is instructive to note that only one subsidiary of Avista had a loss in 2007 – and that only approximated $350,000. (Id. at p.7, ll. 1-3) Accordingly, if one were to utilize the 2007 tax return, since it represents Avista's test year in this case, and otherwise correct for only the previously-discussed computational errors, the tax impact of the $350,000 loss applicable to electric operations would be only $29,000 and the loss allocable to natural gas operations would be only approximately $26,000. (Id. at p.7)

68 Finally, even Mr. Majoros' application of the term "effective tax rate" is "unconventional in this context," as explained by Mr. Falkner:

69
> In a regulatory setting, the term is used frequently to measure the regulatory tax expense compared to the regulatory pre-tax Net Operating Income (NOI) to which it relates in. That is the typical usage of the term and is how the Company uses the term. That, however, is not how Mr. Majoros uses the term. He would use the term to compare tax on the regulated income adjusted for subsidiaries with losses with the utility income. This misrepresents common financial terminology and accounting nomenclature.

70 (Exh. DMF-2, p.8, ll. 5-10) (emphasis in original). In so doing, Mr. Majoros has calculated a meaningless "tax rate" that has no relevance for determining tax expense for ratemaking. As explained by Mr. Falkner, when the Company calculates its tax expense for ratemaking purposes it uses a tax rate of 35%, representing its statutory (and marginal) tax rate. That is not to say, however, that the Company's tax expense will actually be 35% of its pre-tax NOI, because it still must be adjusted for a number of items, including the reversal of a prior year's flow-through and tax credits. Accordingly, a tax expense will no longer be 35% of pre-tax NOI and will, inevitably, be either higher or lower. This does not change the fact, however, that the Company is taxed at a rate of 35% and that is the appropriate tax rate for use in determining tax expense for ratemaking, as explained by Mr. Falkner. (Id. at p.9, ll.3-4)

2. Public Counsel/ICNU's Adjustment is Also Conceptually Flawed.

71 The Company's rebuttal explained why the approach used by Mr. Majoros is not a valid methodology for determining tax liability for multiple entities. These shortcomings were enumerated by Mr. Falkner at pp. 9-11 of his testimony (Exh. DMF-1T). First of all, this approach would arbitrarily "carve up" the consolidated group for purposes of ratemaking. When considering tax expense from a ratemaking perspective, the "operative unit of analysis is not a legal entity, but regulated vs. non-regulated." (Id. at p.9, ll. 19-20) Mr. Majoros, however, has "commingled" the revenues and expenses of the regulated and non-regulated groups, thereby violating principles of cost causation:

72 > . . . to establish cost-justification, the Commission commonly looks for a causal link between the service provided and the expense the Company incurs to provide the service. The tax is calculated as a result of some underlying activity. A tax cannot and does not exist in isolation. A tax is applied to something. If that 'something' is a regulated activity, that 'something' is part of the benefits or costs of the regulated activity, and the tax impact falls on customers. If that 'something' is a non-regulated activity, that 'something' is part of the benefits or costs of the non-regulated activity, and the tax impact does not fall on customers. Mr. Majoros violates the principle of cost-causation by attempting to shift only the tax without reflecting on the nature of the underlying activity that is the subject of the tax. (Emphasis added)

73 (Exhibit DMF-1T, p.10, ll. 2-10)

74 Furthermore, while some legal entities in the Avista Corporation Consolidated Group reported taxable income while others reported taxable losses, Mr. Majoros never explains why customers should enjoy lower tax expense when a non-regulated legal entity reports a tax loss, but otherwise should bear no additional tax expense when the same non-regulated entity reports taxable income. (Id. at p.10, ll. 11-14) Mr. Falkner provided a simple, real-life example whereby Mr. Majoros would share the loss of one of Avista's subsidiaries in 2005 (METALfx) but otherwise would entirely ignore the net income of the same subsidiary in 2006, which nearly offset in its entirety the 2005 loss. In fact, as explained by Mr. Falkner,

the four subsidiaries that otherwise operated with taxable losses of approximately $7.7 million in 2005 operated with taxable net income in 2006 of $4.9 million – a fact ignored by Mr. Majoros. (Id. at p.11, ll. 5-9) His approach is also conceptually flawed in that, under his calculation, any entity that reports a tax loss would share that tax loss with every other legal entity that has a gain – irrespective of whether or not the tax loss is a result of regulated or non-regulated activities. This creates, on its face, an inappropriate cross-subsidy between regulated and non-regulated activities. (Id. at p.11, ll. 10-13)[6]

75 Finally, no cross-subsidy actually exists, contrary to Mr. Majoros' assertions. The non-regulated group is paying tax at the rate of 33.5% in 2005 and 34.9% in 2006, while the regulated group paid tax at 31.5% and 32.6% in those respective years. This demonstrates that no cross-subsidy has occurred under the Company's approach. (Id. at p.11, l. 18 – p.12, l. 2)

76 In the final analysis, however, it is important to understand why the regulated group's effective tax rate is lower than the non-regulated group. As explained by Mr. Falkner, the regulated group has tax credits available to it that are not otherwise enjoyed by the non-regulated group. These tax credits are crucial in the determination of the amount of the taxes paid - a fact that was not recognized by Mr. Majoros. In Avista's case, the primary tax credits in 2005 and 2006 come from the Production Tax Credit (PTC) which the utility receives from the generation of power at its Kettle Falls Generating Station and its Cabinet Gorge Hydro Facility. It is important to recognize that these tax credits are included in the Company's filing and are reflected in its proposed revenue requirement (Id. at p.12, ll. 9-14) As such, these credits are passed through to customers. If these credits were removed from the analysis, the

[6] Finally, as discussed by Mr. Falkner, for the two years covered by Mr. Majoros (2005 and 2006), both the regulated and the non-regulated group reported positive taxable income, which raises the question of why Mr. Majoros would allocate any loss to customers. (Exh. DMF-1T, p.11, ll. 14-16)

effective tax rate for the regulated group would be 35%; stated differently, the reason the actual tax rate dips below 35% is simply due to the presence of these tax credits, which are being passed through to customers. (Id. at p.12, ll. 16-19)

77 Mr. Majoros, with his recommendation, may also have violated the "normalization" provisions of the Internal Revenue Code. These provisions require a regulated taxpayer to use consistent assumptions for its treatment of tax expense, depreciation expense, the reserve for deferred taxes, and for rate base; Mr. Majoros, however, calculates an adjustment for only tax expenses and has not otherwise made an adjustment to the reserve for deferred taxes. (Exhibit DMF-2, p.13, ll. 1-16) Furthermore, regulated taxpayers are also required, under the normalization provisions, to record deferred taxes based on the difference between depreciation for ratemaking and depreciation for tax purposes. By introducing the tax losses and supposed "tax savings" from the non-regulated entities into the calculation, Mr. Majoros potentially violates tax regulations which provide that the deferred tax can be adjusted only for differences related to book and tax depreciation methods. (See Regulation §1.167(1) – 1(h)(2)) (Id.) The Company is precluded from making adjustments related to tax losses or supposed "tax savings" of non-regulated companies. (Id.)[7]

78 Because Mr. Majoros' proposal has the potential to improperly allocate tax benefits of accelerated depreciation between the Company and its customers, if adopted by this Commission, the Company would need to request a Private Letter Ruling from the IRS, in order to be assured that no "normalization" violation has occurred. Mr. Falkner explained why

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7 Mr. Falkner emphasized the uncertainty surrounding whether such an approach would violate the "normalization" rules, inasmuch as what is being proposed here "touches every single adjustment" and "would take quite a bit of analysis." (Tr. p.208, ll. 7-22)

violation of the rules with respect to normalization could result in the denial by the IRS of the Company's ability to claim accelerated tax depreciation on any of its public utility property:

79 As a result, the Company would not be able to claim accelerated depreciation on any of its remaining production, transmission, distribution or other plant that remained subject to cost-basis regulation, resulting in negative impacts on the Company's results of operations, financial condition and cash flows.

80 (Id. at p.14, ll. 16-21) Mr. Falkner, on re-direct examination, explained again why it would still be prudent for the Company to seek a Revenue Ruling, given what would be at stake: "Oh, absolutely, I can't imagine the Company not." (Tr. p.215, ll. 1-10)[8]

81 Finally, it is well to note that the Federal Energy Regulatory Commission long ago abandoned the "consolidated return method," as discussed in Mr. Falkner's rebuttal testimony. (Id. at p.15, ll. 6-17) In Re Columbia Gulf Transmission Co., 23 FERC ¶61,396, Opinion 173 (1983) at p.06, FERC rejected the consolidated tax return method of calculating income taxes, and adopted a "stand-alone" approach. In doing so, it stated in its Opinion No. 173, at p.06, that "the tax allowance should be equal to the tax on the profit the ratepayer will contribute to the Company. In short, the tax allowance should be equal to the tax on the Company's allowed rate of return." FERC went on to observe that, "when an expense is not included in the cost of service (because the Company did not incur that expense in providing service), the deduction created by that expense is not allocated to the ratepayers." (Id. at 07)

82 Moreover, as recently as 2007, this Commission in WUTC v. PacifiCorp rejected a consolidated tax adjustment proposed by ICNU which would have imposed interest expense from the parent company onto the Company, which on its own, had no interest expense. This Commission concluded:

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8 Mr. Falkner also explained that what Mr. Majoros is recommending in this case, is ". . . not what we experienced in Oregon, which is my most recent experience, and to the best of my knowledge it's not what is in place in the other states." (Tr. p.206, ll. 5-9)

83 > . . . [w]e note finally that what ICNU proposes here is tantamount to asking for a tax-true-up. True-up mechanisms, a form of single-issue ratemaking, are not generally favored in utility ratemaking. We reject ICNU's proposed adjustment to reduce income tax as unsupportable.

84 Order No. 08, supra, at paras. 152 and 153 (Case No. UE-061546).[9]

85 For a variety of reasons discussed above, Mr. Falkner ultimately concluded, in his rebuttal testimony, that conceptually, Mr. Majoros' recommendations serve to "commingle" regulatory and non-regulatory activities through the faulty application of an "effective tax rate." (Exhibit DMF-1T, p.16, ll. 14-19) As such, this adjustment ". . . is inequitable, inconsistent with sound ratemaking principles, ignores the actual statutory tax rate that applies to Avista, and potentially violates the normalization provisions of the IRC." (Id.)[10]

C. APPROPRIATE TREATMENT OF NET SALVAGE OR "COST OF REMOVAL" IN DEPRECIATION STUDIES.

1. Introduction/Description of Public Counsel/ICNU Adjustment.

86 Public Counsel/ICNU, through their witnesses Mr. Majoros and Mr. King, propose a depreciation expense adjustment that reduces the Company's filed electric revenue requirement by $3.057 million, and increases rate base by $1.555 million. The corresponding revenue requirement decrease with respect to the natural gas revenue requirement is $1.197

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[9] Although reference was made to a consolidated tax adjustment in the State of Oregon, Mr. Falkner noted that such an adjustment was created by special legislation (S.B. 408) and did not originate with the Oregon Commission, and was a response to "unique circumstances." (Tr. P.217, LL. 6-9) Moreover, Mr. Falkner noted that what is being proposed here is "not what we experienced in Oregon" and "not what is in place in other states." (Tr. p.206, ll. 5-9)

[10] Other state commissions, on policy grounds, have also rejected the consolidated return method. See Re Potomac Elec. Power Co., 124 Pur.4th 1, 22-24 (Md. PSC 1991), or on constitutional grounds (e.g., Re Income Tax Expense for Rate-Making Purposes, 59 Pur.4th 576, 586-87 (Cal. PUC 1984): "We see no public interest that is served by making utility rates a function of profits or losses in non-utility affiliates, as would result from the consolidated return method. Further, we are persuaded that a tax loss is an asset that would be taken either without compensation and without due process of law, or with compensation but for no useful purpose.")

million, with an increase in rate base of $609,000. (Exh. EMA-7T, p.12, ll. 11-16; p.24, ll. 10-19) Essentially, Mr. King, on behalf of Public Counsel/ICNU, has proposed a change to the cost of removal calculations approved within the Company's recently-concluded general rate cases (Docket Nos. UE-070804 and UG-070805).

87 For its part, the Company sponsored the testimony of Mr. Spanos and Mr. Felsenthal, who addressed the depreciation adjustments proposed by Public Counsel/ICNU, insofar as it dealt with net salvage values and the misapplication of financial accounting concepts presented in FAS 143 (Accounting for Asset Retirement Costs). The Company, in its testimony, established that the traditional and widely-accepted regulatory approach is to recover cost of removal on a "straight-line basis" through depreciation charges. This method appropriately matches the recovery of such costs with customers who benefit from the use of the fixed asset that causes the retirement obligation. (Id. at p.12, ll. 18-23.) Accordingly, this approach supports "intergenerational equity." This should be compared with witness King's methodology, on behalf of Public Counsel/ICNU, which produces ever-increasing annual charges that may require annual rate cases, would burden future customers, and would increase the risk that the actual cost of removal would never be recovered if the assets were retired early. (Id.)

88 Mr. King's approach would jettison the long-standing approach that utilizes straight-line depreciation, in favor of a "sinking fund" style approach. More specifically, Mr. King would use a "discounting" approach that would include two elements for determining "cost of removal": The first element would estimate the eventual cost of removal and then discount it to the present time using a discount rate of 3%; the second element would include an inflation component (again 3%) to recognize annual "accretion" of the cost of removal obligation so that, over time, the obligation will increase to match its estimated cost. The inevitable result

of this approach is an ever-increasing annual charge, which ignores principles of intergenerational equity and may require frequent or annual rate cases to fully capture the removal costs that will increase each year in order to recognize this "accretion." (Exh. ADF-1T, p.9, ll. 12-15)

2. Straight-Line Depreciation Remains the Accepted Approach for Purposes of Traditional Net Salvage Accrual.

89 Avista presented the expert testimony of two witnesses on the subject of the appropriate treatment of net salvage or "cost of removal" for purposes of depreciation. Both witnesses boast strong credentials: Mr. John Spanos is Vice-President of the Valuation and Rate Division of Gannett Fleming, Inc., a consulting firm with a long history of providing client services encompassing valuations, depreciation studies and cost allocation. In particular, Mr. Spanos has prepared numerous depreciation studies and has served in the position of a supervisor or manager with respect to the division of Gannett that specializes in depreciation and valuation studies. (See Exh. JJS-1T, pp. 1-3) As such, he has credentials as a certified depreciation expert. (Id.)

90 Likewise, Mr. Alan Felsenthal was retained by Avista to address the appropriate treatment of net salvage, as well as to discuss certain other issues pertaining to the suggested reclassification of accumulated costs of removal to a regulatory liability, and the use of that accumulated cost of removal obligation to offset other costs. Mr. Felsenthal is a Managing Director at Huron Consulting Group, which provides a variety of accounting, tax and consulting services to various industry sectors. During his long career, he has worked as an auditor focusing on financial statements of regulated utilities and in 2002, joined Pricewaterhouse Coopers and became Managing Director in the Utilities Group, performing audits and rate work for regulated entities. As such, through the years, he has focused on

utility accounting, income tax and regulatory issues as the result of auditing regulated enterprises. (See Exh. ADF-1T, pp.1-2; Exh. ADF-2)

91 Both expert witnesses on behalf of the Company strongly disagree with Public Counsel/ICNU's proposal to replace the traditional straight-line method of determining the net salvage component of the annual depreciation accrual rate with a net salvage factor based on the discounted value of estimated future net salvage. Mr. Spanos notes several shortcomings resulting from the use of the "discounted value accrual" approach to net salvage – also known as "sinking fund depreciation." (Id. at p.4, ll. 5-21) Because it is inconsistent with the "pattern in which the plant renders service," it is inequitable because it does not properly match the service value of the plant with the generation of customers being served. (Id.) In the words of Mr. Spanos, "it simply serves to reduce rates for today's customers at the expense of tomorrow's customers." (Id.) By way of contrast, the allocation of net salvage costs on a "straight-line basis" during the life of the related plant – an approach used by nearly all state commissions, including this Commission – serves to charge customers for the future cost of removal during the life of the plant, such that customers that benefit from the plant (i.e., consume its value) are the ones that actually pay for the service. Stated differently, "the net salvage cost of an item is a part of its 'service value' and is, therefore, a part of the cost of providing service and should be collected from the customers that receive the service." (Id. at ll. 14-16)

92 Moreover, as will be discussed below, both Mr. Spanos and Mr. Felsenthal explain why Public Counsel/ICNU has improperly relied on FAS 143, thereby inappropriately applying a standard for GAAP financial reporting on the ratemaking process. Simply put, FAS 143 does not apply to ratemaking in general, and should not be used to prescribe the depreciation methodologies for a regulated utility.

93 Mr. Spanos identified several flaws in the concept of a "discounted value accrual" as proposed by witness King. This approach, sometimes known as "sinking fund depreciation," removes inflation from the estimated future net salvage value, divides this by the average life, and then adds back an amount of "accretion" each year. Because the sum of accruals based on the discounted value is significantly less than the amount required to retire assets at the end of their lives and must rely on the "accretion" amount to ensure complete capital recovery, this results in total expense related to net salvage recovery that is greatest in the final year of service (as the amount of accretion grows during the life of the asset). (JJS-1T, p.5, ll. 9-22)

94 This "back-end loading of capital recovery" can result in significant shortfalls in the event assets are retired even a few years prior to their estimated service lives; moreover, because the "accretion component" increases every year, a rate case must be filed every year in order to properly capture the accrual rate related to net salvage; the application of this "sinking fund" method is also difficult and complex requiring that each vintage of assets must be segregated into groups of equal life in order to correctly calculate the annual factors. (Id.) For these and other reasons, virtually all state commissions have embraced, instead, the use of the straight-line method of depreciation.

95 Likewise, Mr. Felsenthal also addresses the cost of removal calculation as part of the depreciation study. He supports the conclusions of Mr. Spanos, noting:

96
> The traditional and widely-accepted regulatory approach to recover cost of removal on a straight-line basis through depreciation charges is the appropriate methodology for such costs. This method appropriately matches the recovery of such costs with the customers who benefit from the use of the fixed asset that causes the retirement obligation. As such, this approach supports intergenerational equity. Mr. King's methodology, based on a FAS 143-type approach, produces an ever-increasing annual charge that requires annual rate cases and increases the risk that the actual cost of removal will not be recovered. In addition, this method burdens future customers simply to reduce rates for today's customers.

97 (Exh. ADF-1T) (Emphasis added) Accordingly, from a regulatory standpoint, it is important to match revenues with costs so that customers who benefit from the consumption of plant pay for the cost of the plant, including its removal costs, net of salvage. Mr. Felsenthal explains why this "matching principle" is such an important part of the "regulatory philosophy" that is sometimes referred to as "intergenerational equity":

> 98 Intergenerational equity means that the costs generated from a resource are borne by the same group or generation of customers that benefit from the consumption of that resource. To achieve this ratemaking goal, utility revenues should match all the costs of providing service from particular property so that the customers who receive utility service and benefit from the particular property pay for that property's depreciation costs, including costs of removal, over the life of that property.

99 (Exh. ADF-1T, p.7, ll. 14-20) By utilizing a discounted value obligation, as does witness King, this serves to lower current charges when compared to the straight-line approach presently used for ratemaking. Stated differently, his approach would result in an annual cost of removal allowance that is lower in the early years and higher in the later years of the assets' life. Accordingly, in order to recover the cost of removal through time from customers, annual rate increases would be required. (Id. at p.10, ll. 13-21) In the final analysis, Mr. King's methodology results in the "backloading of the cost of removal" thereby deferring the cost recovery "to the wrong generation of customers or not collecting the amounts at all." (Id. at p.11, ll. 4-5) The straight-line approach currently used in this and other jurisdictions, does not suffer from these shortcomings.

100 Staff witness Parvinen, in his cross-answering testimony, also flatly rejects Public Counsel's depreciation adjustment, explaining:

> 101 Again, it basically comes down to the matching principle. The Commission has historically accepted the straight-line remaining life method for determining depreciation expense as the preferred approach to recover from ratepayers the net cost of an asset over its useful service life. The net cost of the asset is the original purchase price, less salvage, plus the cost of removal.

> The beauty of the remaining life methodology is that, as the estimated service life, salvage value, or cost of removal change over time, those changes are reflected going forward over the remaining life of the asset. This levelizes the effects of the changes so at the end of the service life (retirement date) all costs have been recovered from ratepayers. It is, therefore, appropriate to match the dollars collected with the dollars spent. Performing a present value calculation, as Public Counsel proposes, creates a mismatch in timing of the actual dollars collected. The mismatch occurs because, under Public Counsel's proposal, fewer dollars are collected in the early years and more dollars will have to be collected in the later years.

102 (Exh. MPP-1T, p.6, l. 22 – p.7, l. 12) (emphasis added).

103 The dollars collected from customers under the two methods, straight-line and sinking-fund, both serve to reduce rate base until the dollars are needed to cover removal costs. This rate base reduction provides a direct benefit to customers. Although the example provided in Mr. King's Exhibit No. CWK-4, p.3 demonstrates the differences in annual removal costs under the two methods over time, his straight-line vs. sinking-fund example, however, does not reflect the annual benefit to customers from the rate base reduction under the two methods.

104 In Mr. King's example, the current straight-line method would provide a greater rate base reduction (i.e., greater benefit to customers) than the sinking-fund method in the early years, and a lesser reduction in the later years. Although Mr. King's Exhibit CWK-4 shows that customers would be better off in <u>the near-term</u> years under the sinking-fund method <u>when looking solely at the annual expense accrual</u>, he does not expand his example to show the total costs paid by customers over the life of the asset under the two methods, when <u>all</u> costs and benefits of ratemaking are taken into consideration. In short, Public Counsel has not shown that the total costs to customers over the life of the asset would be lower under the sinking-fund method, versus the straight-line method. This is yet another reason that the Commission should not adopt the sinking-fund method.

105 In sum, Public Counsel has produced no analysis that shows that the sinking-fund method provides a lower cost to customers over the life of the asset, as compared to the straight-line method. In fact, Exhibit ADF-3, sponsored by Public Counsel, suggests that just the opposite is true. This exhibit was introduced by Public Counsel for purposes of cross-examination, and consists of an article by John S. Ferguson entitled Fixing Depreciation Accounting, Public Utilities Fortnightly (October 2008). As noted by Company Witness Felsenthal, this article actually lends support for the Company's position in favor of straight-line (ratable) depreciation and the need to honor the principle of "intergenerational equity." As noted in the article:

> 106 Regulators also were ahead [of the accounting profession] in recognizing there are three components to depreciation – investment, salvage, and removal expenditures – and that accurately charging these costs to ratepayers necessitates recording them ratably over the useful life of the related PP&E [Property, Plant and Equipment] . . . .
>
> 107 This treatment assures that ratepayers are charged no more and no less than the costs being incurred to serve them, at the time the service is rendered and the costs incurred – which is known as the regulatory principle of intergenerational ratepayer equity.

108 (Exh. ADF-3, p.2) (emphasis added). The author of this article went on to comment on the "unfortunate" challenges to "ratable treatment of removal costs" that actually serve to increase the costs to be borne by ratepayers over time:

> 109 The ratable treatment of removal costs through depreciation for regulatory accounting purposes has a long history, but periodically is challenged by proposals to defer recording and recovery. Such challenges also have a long history, but have taken on renewed vigor as a consequence of FASB Statement of Financial Accounting Standards No. 143. *Accounting for Asset Retirement Obligations*, (SFAS 143), issued in 2001.
>
> 110 Challenges to ratable treatment of removal costs for regulatory purposes are unfortunate, because they lead to proposals for deferral mechanisms that, if accepted by regulators, increase the costs to be borne by ratepayers over the life of the related PP&E, thereby increasing energy costs and damaging the competitiveness of the state (*see "Depreciation Shell Game," Fortnightly, April 2008).*

111 (Id. at p.3) (emphasis added).

3. FAS 143 Does Not Prescribe Depreciation Methodologies for Regulated Utilities.

112 Mr. King, on behalf of Public Counsel/ICNU, seeks to draw support for his proposal to allocate the discounted value of future net salvage from accounting pronouncements contained within FAS 143, issued by the Financial Accounting Standards Board ("FASB"), insofar as such standards apply to financial reporting as part of Generally Accepted Accounting Principles (GAAP). In so doing, however, Mr. King has incorrectly superimposed a standard for financial reporting on the ratemaking process. (See Exh. JJS-1T, p.7, ll. 2-6) Stated differently, the accounting pronouncements stated in FAS 143 do not affect the regulatory policies of this Commission and do not prescribe depreciation methodologies for a regulated utility such as Avista. As such, FAS 143 does not apply to ratemaking in general, or to this proceeding in particular. (Id. at p.15, ll. 3-6)

113 Mr. Felsenthal, on behalf of the Company, elaborates on this point:

114 > FAS 143 only addresses the accounting and financial reporting under GAAP. It does not address regulatory accounting or ratemaking. Regulatory assets and liabilities provide a vehicle to recognize the economic effects of the ratemaking process, to the extent there are differences between the financial reporting and ratemaking treatment of certain costs. This is also true for non-regulated entities – the FASB does not dictate how to determine prices.

115 (Emphasis in original) (Exh. ADF-1T at p.21, ll. 18-22) Accordingly, FAS 143 does not prevent Avista or other utilities from continuing to recover costs of removal (i.e., retirement obligations) in the approved depreciation rates in the same manner as they always have. In fact, Mr. Felsenthal quotes directly from FAS 143 wherein it is acknowledged that regulated utilities can recover removal costs over the life of the assets through depreciation rates:

116 > [Quoting from FAS 143] The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement, and, therefore, may result in a

difference in the timing of recognition of period costs for financial reporting and rate-making purposes.

117 (Emphasis added) (Id. at p.24, ll. 21-25)

118 Mr. Felsenthal went on to explain the different objectives served by financial accounting and regulatory accounting: Financial accounting is used to develop financial statements for reporting financial information in accordance with GAAP – i.e., to "establish general principles and provide a common accounting yardstick across companies." (Id. at p.25, ll. 13-18) Regulatory accounting, on the other hand, is governed by FERC and the various state and local regulatory commissions and is designed to provide accounting information in a manner that assists utility regulators in their ratemaking treatment of regulated companies. As such, utilities are permitted to establish revenue requirements to recover their capital and operating costs. As noted by Mr. Felsenthal, a "fundamental regulatory principle [is] that ratepayers should pay for the appropriate costs to provide service, with appropriate consideration of factors such as intergenerational equity, prudence and cost causation." (Id. at p.26, ll. 6-11)

119 Nor does FERC Order 631, issued in April 2003, change the landscape. That Order prescribes regulatory accounting treatment that adopts the requirements of FAS 143 for legal retirement obligations and amended the Uniform Systems of Accounts to include the appropriate asset retirement obligations. For non-legal Asset Retirement Obligations (AROs), however, FERC "concluded that such amounts can remain on the books of the regulated enterprises to the extent that they represent estimated amounts included in the revenues collected from ratepayers to be used to fund actual cost of removal expenditures," as noted by Mr. Felsenthal. (Id. at p.27, ll. 5-16) As such, FERC Order 631 did not change regulatory accounting and did not address the ratemaking treatment of cost of removal; it simply

supports differences between the ratemaking and regulatory accounting treatment by including regulatory asset and regulatory liability accounts. (Id.)

4. Overwhelming Precedent Supports the Continued Use of Straight-Line Accrual.

120 Recognizing concerns over the proper matching of costs with the generation of customers being served by the assets, the vast majority of commissions embrace the straight-line method of accrual– as opposed to the use of a discounted value or sinking fund method. As previously noted by Staff Witness Parvinen, this Commission has historically accepted the straight-line method for determining depreciation expense as the preferred approach to recover the net cost of an asset over its useful service life. (See Exh. MPPP-1T, p.6, l. 22 – p.7, l. 2) Moreover, as explained by Company Witness Spanos, some 47 state utility commissions primarily or exclusively use the traditional method of accruing negative net salvage on a straight-line basis to determine the appropriate depreciation rates. (Exh. JJS-1T, p.19, ll. 13-19) In his testimony, Mr. Spanos also quoted from excerpts from three different state commissions that have recently dealt with the issue of net salvage. The Missouri Public Service Commission, in its 2005 Order involving Laclede Gas Company, concluded:

> 121 The Commission finds that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption. The Commission further finds that the method utilized by Laclede is consistent with that fundamental goal.

122 (In Re Laclede Gas Co., Missouri P.S.C., Case No. GR-99315 (Jan. 11, 2005), 2005 WL 65953 at p.5) (Exh. JJS-1T, p.20, ll. 1-6) Mr. Spanos then quoted from an Order of the Indiana Commission reaching a similar conclusion:

> 123 . . . Current customers are receiving service from PSI's generation facilities. A part of the costs of those facilities is dismantlement upon retirement. Therefore, we do not believe it would be appropriate for

the Company to backload the dismantlement costs for future ratepayers to pay when the facilities associated with these costs are providing service to current customers. Rather, we find it appropriate that these costs be shared by all customers that received service from PSI's generation facilities. Accordingly, this Commission finds that dismantlement costs are properly included in determining the depreciation rates approved in this case.

124 We believe that there is a sound basis for the traditional approach on this issue that is utilized by a majority of states . . ..

125 (In Re PSE Energy, Inc., 234 P.U.R. 4th 1, 65-66 (Ind. U.R.C. 204).) Finally, similar proposals for the use of a discounted net salvage value were also rejected by the California Commission, in an excerpt discussed in Mr. Spanos' testimony. (Exh. JJS-1T, p.21, ll. 15-28) (See, In Re San Diego Gas & Electric Co., et al., Case No. A06-12-009, 21-22 (May 22, 2007))

126 Nor was Mr. Spanos aware of any authoritative text on the subject of depreciation that otherwise supports Mr. King's proposals to accrue on the basis of discounted costs or to expense net salvage costs. (Exhibit JJS-1T, p.18, ll. 7-25)

5. Avista's Depreciation Rates Were Recently Reviewed and Approved by this Commission.

127 In Docket Nos. UE-070804 and UG-070805, Avista proposed changes to its depreciation rates, which were incorporated into an uncontested settlement stipulation joined by all parties, including Public Counsel/ICNU. As such, these depreciation rates were implemented effective January 1, 2008.

128 The rates were based on a depreciation study of the Company's electric, gas and common plant and service that was performed by its consultant, Gannett Fleming, in 2005 and as further modified for changes proposed by the parties in the above-referenced dockets. This recent depreciation study was the subject of extensive discovery. As part of its review of the depreciation study results, Commission staff recommended certain adjustments to cost of

removal accruals for four different FERC accounts. In the Settlement Agreement, all parties agreed to those changes to the depreciation rates – none of which involved a departure from the straight-line method for treating costs of removal.

129 Because Avista operates in three jurisdictions, Washington, Idaho and Oregon, it is necessary for it to coordinate any change in depreciation rates in all jurisdictions. Accordingly, the depreciation study, as modified, was reviewed, approved and implemented in all of the Company's jurisdictions on January 1, 2008.

130 In the instant case, Public Counsel/ICNU have not presented compelling arguments justifying a departure from either the Company's recently-approved depreciation study in all three of its service jurisdictions, or a departure from the use of straight-line depreciation principles, as embraced by nearly every commission in the country. (See Exh. JJS-1T, pp. 8-11)

D. PUBLIC COUNSEL/ICNU'S PROPOSAL THAT COSTS OF REMOVAL BE RECLASSIFIED FROM ACCUMULATED DEPRECIATION TO A REGULATORY LIABILITY ACCOUNT SHOULD BE REJECTED.

131 Beginning at page 10 of his testimony (Exh. MJM-1TC), Public Counsel/ICNU witness Majoros proposes that the cost of removal amounts be reclassified from accumulated depreciation to a "regulatory liability" account to "recognize the ratepayers' security interest in these monies until spent on their intended purpose." On rebuttal, Company Witness Felsenthal explained why this proposal to reclassify $209.4 million of accumulated costs of removal included in accumulated depreciation to a regulatory liability account is unnecessary and inappropriate. (Exh. ADF-1T, p.4, ll. 16-23) First of all, Avista maintains records within the accumulated depreciation accounts that already track the cost of removal. But, more importantly, Avista is simply not permitted to remove amounts previously accrued for

removal costs from accumulated depreciation accounts and record them in income or otherwise apply them to some other account without prior regulatory approval. (Id.)

132 As further explained by Mr. Felsenthal, the expenses included in rates charged to customers are otherwise appropriately accounted for in accumulated depreciation, and there is "no need to segregate these funds into a specific account or lock box to ensure that these funds will be spent for their intended purpose or that any unspent funds will be used to reduce customer rates in the future." (Id. at p.12, ll. 12-14)

133 No regulatory liability account is otherwise necessary to capture the accumulated cost of removal. There is no FASB requirement or FERC requirement to otherwise record accumulated depreciation as a regulatory liability. The FERC-authorized uniform system of accounts simply require that separate subsidiary records be maintained to identify the accrual of removal cost in accumulated depreciation. (Id. at p.12, ll. 17-21) Even more to the point, Avista is not permitted to remove amounts previously accrued for removal costs from accumulated depreciation and record them in income or otherwise apply them to some other account without regulatory approval. Instead, Avista must follow FERC's guidance in its Uniform System of Accounts that has been adopted by this Commission. (See WAC 480-100-203) Any deviation from such can only be accomplished after "due notice and order of this Commission." (WAC 480-100-203(3)) There is no reason, therefore, to now reclassify the accumulated cost of removal as a regulatory liability, thereby requiring this Commission to approve such a deviation from the Uniform System of Accounts. (Exhibit JJS-1T, p.13, ll. 8-23) This is especially true, inasmuch as there would be no effect on the revenue requirements in this case resulting from Public Counsel/ICNU's proposal.

134 Moreover, Avista would be unable to transfer the costs of removal from Account 108 and record accumulated depreciation as a regulatory liability, even if it wanted to. Uniform

System of Accounts, Account 108, clearly states that items in accumulated depreciation are prohibited from being transferred without the prior authority of FERC:

135 The Utility is restricted in its use of the accumulated provisions for depreciation to the purposes set forth above. It shall not transfer any portion of this account to retained earnings or make any other use thereof without authorization by this Commission (FERC).

136 (See Exh. ADF-1T, p.15, ll. 1-8) Moreover, as explained by Mr. Felsenthal, FERC has issued several letters to utilities otherwise prohibiting them from reallocating accumulated depreciation. (Id.) In conclusion, while this Commission could order Avista to transfer accumulated cost of removal to a regulatory liability, albeit serving no useful purpose, Avista must also seek the approval of FERC's Chief Accountant to approve any departure from the Uniform System of Accounts.

137 Staff Witness Parvinen also agrees that there is no WUTC or FERC requirement that Avista be required to or should otherwise book the amounts as a regulatory liability. He is correct in observing that "customers receive no greater safeguard with the proposed creation for a regulatory liability than under the current regulatory treatment." (Exh. MPP-1T, p.3, ll. 14-16) Mr. Parvinen elaborated on his assertion that the current regulatory treatment provides sufficient assurance that customers will receive the benefits of all cost of removal collections:

138 . . . Mr. Majoros, on p.9, ll. 12-14 of his direct testimony, states that customers will face a strong possibility of losing substantial prepaid funds for cost of removal if the funds are not protected by placing them in a regulatory liability account. This is absolutely incorrect. Under the traditional approach, when an asset is finally retired and the actual cost of removal is known, that there has been an overcollection, then the amount stays in the Accumulated Depreciation account to reduce the overall cost of removal to be recovered on all other assets within the asset account through the remaining life approach employed by this Commission. The Company does not have the ability to keep any unspent funds (if there were to be any); rather, they continue to go to the benefit of customers.

139 (Emphasis added) (Id. at p.4, ll. 11-20.) In the final analysis, the recommendation to create a regulatory liability would otherwise have no revenue requirement impact, and is entirely unnecessary, serving no useful purpose.

E. PUBLIC COUNSEL/ICNU'S PROPOSAL TO OFFSET THE SETTLEMENT COSTS OF CERTAIN CONFIDENTIAL LITIGATION AGAINST A PORTION OF AVISTA'S ACCUMULATED COST OF REMOVAL SHOULD BE REJECTED.

140 Mr. Majoros recommends, at page 18 of his testimony, that a portion of Avista's accumulated cost of removal should be used to offset costs of reaching settlement with respect to certain Confidential Litigation, discussed elsewhere in this Brief. Such a proposal is, again, clearly wide of the mark. To begin with, the accumulated costs of removal are not "excess" and otherwise available to offset other costs; instead, they are required to pay for Avista's actual removal costs, as explained by Mr. Felsenthal. (Exh. ADF-1T, p.16, ll. 5-16) Mr. Parvinen, on behalf of staff, also agrees that it is inappropriate to use cost of removal collections for "any other purpose than cost of removal." (Exh. MPP-1T, p.5, ll. 17-20)

141 In the final analysis, the recovery of Confidential Litigation costs should be viewed as a separate issue and should not otherwise be "confused with the recovery of cost of removal," as explained by Mr. Felsenthal. (Exh. ADF-1T, p.16, ll. 5-10) This would be no more appropriate than otherwise "diverting income tax accruals, accumulated depreciation or other legitimate reserves, credits or liabilities to offset the recovery of other costs." (Id.)

142 Again, Mr. Parvinen notes the "bad precedent" that would be created by such a proposal:

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> . . . These funds are specifically collected for the future cost of removal. Mr. Majoros does not state from where the actual cost of removal will come from when it is time to pay removal costs if the funds have, instead, been used to offset other current costs as he proposes. It just does not make intuitive sense and sets a bad precedent by asking future rate payers to pay for yesterday's costs.

144 (Exh. MPP-1T, p.6, ll. 4-8) (emphasis added)

145 Finally, the Uniform System of Accounts (Account 108) does not allow amounts to be transferred to any other classification without prior authorization of FERC's Chief Accountant; inasmuch as the transfer to a regulatory liability and amortization of such liability to reduce an unrelated operations and maintenance expense is "against Uniform System of Accounts guidance [it is] not likely to be accepted by FERC." (Id. at p.16, ll. 11-16)

F. ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL (A&G) EXPENSES

1. Introduction: The Total Impact of the Adjustments for A&G are Essentially the Same for the Settlement and Public Counsel/ICNU

146 Before discussing individual Administrative and General (A&G) expense items, it is well to note, as does Company Witness Andrews, that, taken in their entirety, the total level of adjustment to A&G expenses are nearly the same in the Settlement, as compared with the litigation position of Public Counsel/ICNU. (Exh. EMA-7T, p.6, ll. 1-9) Ms. Andrews, in Table 1 at page 3 of her rebuttal testimony (line 16), demonstrates that the total adjustments for electric A&G expense in the Settlement reflect a reduction of $1,852,000, while Public Counsel/ICNU's adjustments to A&G total $1,896,000 – for a difference of only $44,000. (Exh. EMA-7T, p.6, ll. 4-8) (For natural gas, the total of the A&G adjustments is also quite similar: A&G expenses are reduced by $466,000 in the Settlement, as compared with $559,000 in the testimony of Public Counsel/ICNU.) (Exh. EMA-7T, p.8, l. 14) Accordingly, with respect to total A&G expenses, the "end result" of the Settlement is essentially the same as reflected in the positions of Public Counsel/ICNU.

147 Of course, as one would expect, individual items that serve to make up the total of A&G expenses differ between the parties. It is well to remember, however, that as in any settlement, there is a give-and-take with respect to particular items that comprise the package

of A&G expenses. This is perhaps best illustrated by noting that the Company, itself, as part of the Settlement, agreed to remove all of 2009 non-officer and union wage increases totaling $1.19 million – even though, historically, rate period wage increases have been accepted by this Commission. (Exh. EMA-7T, p.6, ll. 12-23) This one adjustment serves, in and of itself, to offset many of the other A&G adjustments prepared by Public Counsel/ICNU. Interestingly enough, Mr. Majoros, otherwise supported the inclusion of this wage adjustment, in order to capture non-officer and union compensation for 2009. (Id.) The Settlement also removed, or otherwise adjusted, a variety of other A&G items identified in the testimony of Ms. Andrews: "officer compensation" ($140,000/electric; $37,000/gas); "incentive compensation" ($415,000/electric; $109,000/gas); and "sponsorship expenses" ($109,000/electric). In total, the Settlement removes $1,852,000 of electric A&G expenses and $466,000 of natural gas A&G expenses. (Id. at p.7, ll. 6-10)

148 It may be argued by Public Counsel/ICNU that the Settlement does not remove certain miscellaneous items such as particular dues/donations or advertising/sponsorships. (See MJM-1CT, pp. 34-37) These contested items total $159,000 for electric results and $39,000 for gas. As explained by Ms. Andrews, on cross-examination, the give-and-take of negotiation on the total package of A&G adjustments already took into account such items; these items were offset many times over by the Company's willingness to forego a $1.19 million adjustment for 2009 non-officer and union wage increases – a rate-year adjustment typically recognized by the Commission. (See Tr. p.220, ll. 15-17; p.222, ll. 18-25; p. 226, ll. 10-24) Ms. Andrews was quite clear in her explanation of how the settlement process resulted in a

"full package" that incorporated disallowances that more than offset these miscellaneous items. (Id., at p.226, ll. 10-25 and p.232, ll. 7-10)[11]

2. Adjustment for Executive Compensation ($389,000/Electric; $102,000/ Gas)

149 Public Counsel/ICNU recommend adjustments for officer compensation relating to three elements: (1) the estimated rate used for 2008 base pay; (2) the use of an estimate of 5% for the 2009 pay increase; and (3) the appropriate percentage split of time charged to utility and non-utility operations. (See Exh. EMA-7T, p.14, ll. 8-14) The Company's rebuttal addresses each of these elements, in turn. Were this case to be fully litigated, Avista would agree with Mr. Majoros to the use of the actual 2008 salary increase, in lieu of an estimate.[12] Secondly, while the Company originally used a 5% increase for planned 2009 salary increases for officers, based on what was estimated at the time for 2009 salaries, the Company now has the benefit of the Conference Board's "2008-2009 Salary Increase Survey Results," which includes the responses of over 358 organizations. As recognized by Mr. Majoros, the projected salary increase budgeted for executives for the utility industry, as contained within that report, is 4%; and, therefore, Avista would substitute a revised estimate of 4% for 2009 executive salary increases. (Exh. EMA-7T, p.15, l. 21 – p.16, l. 5)[13]

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[11] It may even be argued by Public Counsel that the Commission simply cannot approve a Settlement that includes what Public Counsel may characterize as "legally impermissible" charges. Is it any more "legally permissible" to exclude items that make up the cost of service and are prudently incurred? (See e.g., 2009 wage increases and property additions that were excluded.) Are the resulting rates really "just, reasonable or sufficient"? (See RCW 80.28.020) These and other reasons explain why the courts have recognized that it is the "end result" that matters. (See, Hope, supra)

[12] This would serve to revise the Company's pro forma adjustments by a reduction of approximately $21,000 for electric and $6,000 for natural gas. (Exh. EMA-7T, p.15, ll. 13-15)

[13] This would serve to reduce the pro forma executive compensation amount by $14,000 for electric and $4,000 for natural gas. (Exh. EMA-7T, p.16, ll. 3-5)

150 Avista disagrees, however, with Mr. Majoros' use of a 75%/25% split of executive time to utility and non-utility operations for certain executives. While he is correct that the specific allocations, by individual officer, are based on an "estimate" – that estimate is well-founded in the "informed judgment of each officer who was individually surveyed concerning their use of time," as testified to by Ms. Andrews. (Exh. EMA-7T, p.16, ll. 12-16) This individual estimate, by officer is reviewed each year. (Id.) Furthermore, Mr. Majoros misses the point when he argues that only a few officers, in fact, changed their percentage for 2007 to a lower percent charged to non-utility operations as a result of the sale of Avista Energy in that year. This fails to recognize that the individual allocations of time of each executive were for the 2009 pro forma period – not 2007. As explained by Ms. Andrews, the 2009 pro forma period allocations are different than 2007, because of an overall change in the level of subsidiary activities. (Id.)[14]

3. Adjustment to Incentive Compensation ($383,000/Electric; $100,000/Gas)

151 Mr. Majoros, on behalf of Public Counsel/ICNU, takes issue with the Company's pro forma incentive adjustment that utilized a six-year average; instead, he used the actual expense included in the 2007 test period. (See Exh. MJM-1TC, pp. 31-33) In reply, Company Witness Andrews explained why it was appropriate to use a multiyear average, where it is difficult to determine, on an annual basis, a representative level of what the future rate year expense or revenue should be. (Exh. EMA-7T, p.17, l. 19 – p.18, l. 4) She noted that, in fact, this Commission has in several instances approved the use of averages over time, where

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[14] Finally, it should be recognized that the Settlement Agreement, itself, adjusts for an error within the Company's computation of the pro forma executive salary adjustment, as part of the process of adjusting the actual 2007 salary level to the 2009 pro forma level, which would have overstated the revenue requirement charged to the utility operation by $140,000 for electric, and $37,000 for natural gas. (Exh. EMA-7T, p.15, ll.4-8; see also, Summary Table of Adjustments at p.4 of Settlement Agreement/Exh. 5)

appropriate, with respect to, e.g., injuries and damages, storm damages, power plant availability, and transmission revenues, etc. (Id.) This helps avoid the "peaks and valleys" of a particular revenue or expense item in a single year, thereby avoiding the distortion of revenue requirement for that year. (Id.) According to Ms. Andrews:

152 Due to the volatility of levels of incentive payout from year to year, incentive expense is a prime candidate for using some form of an average in order to minimize the fluctuations impacting ratepayers from one year to the next, and helps to normalize incentive expenses through time.

153 (Id. at p.18, ll. 15-18) The six-year average (2002 – 2007) was selected because the incentive plans in place for each of those years were similar, if not identical, and 2002 was the first year in which the current incentive plan was implemented. (Id. at p.18, ll. 20-23)

4. Adjustment for Directors' Compensation and Shareholder Expenses ($396,000/Electric; $103,000/Gas)

154 Public Counsel/ICNU Witness Majoros removes 100% of expenses relating to shareholder services and 50% of directors' compensation. (Exh. MJM-1TC, pp. 37-38) First, with respect to the removal of shareholder expenses, he argues that, since Avista is a publicly-traded company, these costs are for the sole benefit of shareholders, who should bear the entire cost. While he acknowledges that Avista is a publicly-traded company, he fails to grasp the significance of that. As explained by Ms. Andrews:

155 As a publicly-traded company, these costs are a necessary expense of doing business to support financing of the utility and to maintain access to capital from investors. Access to capital markets is necessary in order to allow the utility to build and maintain the infrastructure necessary to provide safe, reliable and efficient service. It is clearly necessary to incur costs to maintain this access to markets for the benefit of our customers. Mr. Majoros has simply thrown out all such expenses and has not otherwise identified any particular expenses that were improperly incurred. (Emphasis added) (Exh. EMA-7T, p.19, ll.8-13)

156 Moreover, Mr. Majoros, although he "recognizes that directors play a role in the management of a company," arbitrarily removes 50% of their compensation. (Exh. MJM-1TC

at p.38) Nowhere has he demonstrated that overall director compensation levels are out of line with industry averages or are otherwise imprudent. Company Witness Andrews speaks to the necessity of recruiting and retaining qualified directors to provide guidance for the utility. It is a necessary cost of business, as a publicly-traded utility. Such a publicly-traded utility, needing access to the capital markets, could not operate effectively, "or at all," without a Board of Directors. (Id. at p.19, ll. 15-23)

5. Adjustment for Directors' and Officers' Insurance ($406,000/Electric; $106,000/Gas)

157 Mr. Majoros has also removed 50% of the Company's Directors' and Officers' (D&O) insurance expense, contending that a portion of this expense is designed to benefit shareholders. (Exh. MJM-1TC, pp. 38-40) His logic, however, is flawed, and his recommendation is not based on any demonstration whatsoever of imprudence.[15]

158 Of course, it is well understood that D&O insurance serves to address the risks incidental to serving as a director or officer of a corporation. Simply put, the Company would be unable to attract or retain capable individuals for the Board of Directors or to otherwise serve as officers, without such coverage. Certainly, any rewards of serving as a director or officer would be "enormously overshadowed by the risks of D&O claims," as explained by Company Witness Andrews. (Id. at p.21, ll. 4-15) Nowhere has Mr. Majoros demonstrated any imprudence with respect to the level of coverages procured or the terms with respect to such coverage.

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[15] The D&O insurance reflected in the test period reflects Avista's purchase of D&O liability insurance policies with combined limits of $100 million, for which it paid insurers $2.4 million. For the 2007 test period, Avista allocated one-third of this expense to subsidiaries and two-thirds (or $1.6 million) to utility operations. This utility expense, in turn, was further allocated among utility jurisdictions and services. (Exh. EMA-7T, p.20, ll. 14-19)

159 In fact, Mr. Majoros, in his testimony, states that, "yes, I agree that D&O insurance is a necessary business expense." (Exh. MJM-1TC, at p.40) And that ". . . the need for this insurance is brought on, in part, by the Company's status as a publicly traded company." (Emphasis added) (Id.) This serves to underscore the point that Avista needs access to public capital markets to finance its operations for the benefit of customers – all of which requires directors and officers who are willing to serve in that capacity.

160 Mr. Majoros, however, is wrong in suggesting that the coverage is otherwise designed to protect shareholders, per se; they are not the named beneficiaries and they did not pay the premiums (ratepayers did). Rather, the purpose of the insurance is not to pay shareholders, but to address the financial exposure risks of directors and officers. Investors in common stocks are, or should be, very aware of the risks of investing. The D&O insurance is not designed to hold them harmless from that investment risk. Shareholders also understand that a company's success is dependent, in large part, on the decisions made by executives and directors of the organization, who must be willing to serve in that capacity. (See Exh. EMA-7T, p.22, ll. 20-26)[16]

G. PUBLIC COUNSEL/ICNU'S PROPOSED DISALLOWANCE OF EXPENSES ASSOCIATED WITH THE SETTLEMENT OF THE CONFIDENTIAL LITIGATION SHOULD BE REJECTED.

161 The Settlement Stipulation provides for agreed-upon treatment of certain "Confidential Litigation" and the recovery of the costs of settling this matter involving the claims by the Coeur d'Alene Tribe arising out of the United States Supreme Court 2001 decision holding that a portion of Lake Coeur d'Alene is owned in trust by the United States

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[16] Indeed, the purpose and benefit of D&O insurance is not unlike that of other insurance obtained by the Company, such as property insurance and general liability coverage – all of which are necessary business expenses that must be incurred in order to operate. (See Exh. EMA-7T, p. 23, ll. 1-4)

for the Tribe.[17] (See Exh. 5, §III.A.(n), at p. 11) The Coeur d'Alene Tribe has asserted claims that Avista has stored water during parts of the year on that portion of Lake Coeur d'Alene held in trust for the Tribe for later use by Avista's hydroelectric facilities on the Spokane River. The Settlement, itself, provides for agreed-upon accounting treatment for this Settlement: The Stipulating Parties agree that the pro forma costs of this dispute were prudent and have agreed to defer as a regulatory asset (an Account 182.3 – Other Regulatory Assets) Washington's share of the depreciation/amortization associated with these costs, together with a carrying charge on the deferral as well as a carrying charge on the amount of costs not yet included in rate base, for subsequent recovery in rates. (Id.) Any costs that would otherwise exceed the cost pro formed into the case would be addressed in a separate filing. This accounting treatment was similar to that agreed upon by the Stipulating Parties with respect to two other issues that are not otherwise contested by Public Counsel/ICNU: (1) Spokane River Relicensing and (2) settlement of the Montana Riverbed Litigation.

162 The Settlement with the Tribe would provide for the payment of $25 million in 2008, $10 million in 2009 and $4 million in 2010 for resolution of the past trespass and Section 10(e)[18] charges. The future Section 10(e) payments are flat annual payments for the first 20 years of the license of $400,000 and $700,000 flat annual payments for the remaining years of the license. The Settlement also provides for a one time payment of $32,000 for

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purposes of securing a 50-year right-of-way easement to maintain its existing transmission lines across Tribal Trust Lands. (Exh. TEP-4TC, p.19, ll. 6-13)

163 Company Witness Pessemier filed both confidential direct and rebuttal testimony and exhibits providing a detailed history of this litigation and an explanation of why the proposed Settlement was prudent and in the best interests of Avista's ratepayers. (See Exh. TEP-1TC through Exh. TEP-5C) That complex history will not be repeated here. Suffice it to say, however, that the proposed settlement avoids very substantial exposure on the part of the Company and its ratepayers, were a court to find liability and assess damages with respect to the Company's use of Lake Coeur d'Alene. [redacted]

CONFIDENTIAL per Protective Order in WUTC Dockets UE-080416 and UG-080417

164 In very limited testimony on this issue, at pp. 14-18 of Mr. Majoros' direct testimony, Public Counsel/ICNU put forth the entirety of their recommendation regarding this matter. (See MJM-1TC, pp. 14-18) He recommends that the Commission deny Avista cost recovery associated with payments associated with this litigation, thereby removing $2.4 million of electric revenue requirement from the Company's original filing, and otherwise reducing electric rate base by approximately $15.1 million. (Id.) In the alternative, were the Commission to otherwise accept these costs associated with the litigation, he argues that

Avista should be required to use the regulatory liability resulting from Public Counsel/ICNU's proposed reclassification adjustment, discussed above, to otherwise "offset" any of the cost of this settlement with the Tribe. (Mr. Felsenthal's testimony, on behalf of the Company, as discussed above, explains why this particular proposal to "offset" is not permissible.) Accordingly, were the position of Public Counsel/ICNU accepted by the Commission, it would result in a substantial write-off of prudently-incurred costs associated with the settlement of this ongoing litigation.

165 Mr. Majoros simply contends that Avista somehow "admitted to trespass which is not prudent," and that is the extent of his analysis. (See Exh. MJM-1TC, p.16) As explained by Ms. Pessemier, however, Avista has never admitted to trespass. She explains why such a statement of Mr. Majoros reflects a "fundamental misunderstanding of the issues and the extremely complex history" associated with this matter. (Exh. TEP-4TC, p.4, ll. 3-10) Simply put, there was no knowing trespass on the part of Avista. It was not until the legal process, itself, was concluded with the U.S. Supreme Court's decision in 2001 that Avista definitively knew that it was, in fact, exposed to a trespass claim by the Tribe, as explained by Ms. Pessemier. (Id.) In that 2001 decision (Idaho v. United States, 533 U.S. 262 (2001)), the United States Supreme Court held that the post-statehood ratification of the 1887 and 1889 treaties demonstrated Congressional intent to reserve the submerged lands of the Lake for the benefit of the Tribe. This had presented a very close question for the Court, which rendered a 5/4 decision; indeed, four of the dissenting Justices found, instead, that the State of Idaho's ownership of the submerged lands of the Lake had been established "beyond a shadow of a doubt." (Exh. TEP-4TC, p.9, ll. 4-16)

166 In fact, even prior to the Supreme Court's decision in 2001, the State of Idaho, itself, had consistently claimed exclusive ownership of the Lake and had exercised unchallenged

control, as discussed in Ms. Pessemier's rebuttal testimony. (Id. at p.9, l. 20 – p. 10, l. 26) According to Ms. Pessemier: ". . . given the control of the Lake exercised by Idaho and the lack of control exercised by the United States, it was reasonable for Avista and others to believe that ownership of the Lake passed to Idaho when it was admitted to the Union in 1890." (Id. at p.10, ll. 24-26) Clearly, therefore, there was no basis for a trespass claim until this matter was finally resolved by the United States Supreme Court in 2001, and any suggestion by Public Counsel/ICNU regarding prior trespass by Avista is misplaced.

167 Moreover, even after the 2001 Supreme Court decision to quiet title to the Lake in favor of the Tribe, Avista still had reason to believe that its use of the Lake was authorized by virtue of: (1) the previous transfer of rights from the Tribe to a Mr. Frederick Post and then from Mr. Post to Avista, authorizing the use of the Post Falls Dam site for water power purposes; and (2) the issuance by the United States of a permit to Avista in 1909 to otherwise inundate certain Reservation uplands. (Id. at p.12, ll. 18 – p.13, l. 2)

168 In short, there were no past management mistakes, involving knowing trespass, as asserted by Public Counsel/ICNU. Not only were these matters not resolved until 2001, but Avista could not have acted sooner to resolve the legal issue, as explained by Ms. Pessemier. (Id. at p.5, l. 10 – p.6, l.10) The Tribe, itself, first raised the issue of Lake ownership in 1973, but could not prosecute an action against the State of Idaho to resolve the issue in federal court because of Idaho's sovereign immunity; and Idaho, for its part, could not bring an action against the Tribe to resolve the issue because of the Tribe's sovereign immunity. The only remaining party that had legal standing to resolve the issue was the United States which, as explained by Ms. Pessemier, inexplicably waited until 1994, some 104 years after Idaho became a State, to bring an action against Idaho in federal court to determine the Lake ownership. (Id.) Accordingly, Avista was caught in the middle of a controversy between the United States, the Tribe and the State of Idaho, and had no legal standing to bring a prior

action to determine the ownership of the Lake. Ms. Pessemier explained why Avista had made "sound management decisions" over the years:

> 169 Avista made sound management decisions over the years. If Avista's management had agreed to either compensate the Tribe for trespass or pay usage charges prior to the United States Supreme Court ruling, it could have been criticized for imprudently making payments before the ownership issue was resolved. With respect to Mr. Majoros' testimony that Avista failed to conduct title searches and surveys, such searches and surveys led to the conclusion that the State of Idaho, not the Tribe, owned the Lake. Moreover, a challenge to Idaho's ownership of the Lake ultimately had to be decided by the Courts and that process was not concluded until 2001.

170 (Id. at p.6, ll. 3 – 9)

171 Moreover, the treatment of this issue in the Settlement Stipulation does not constitute "retroactive ratemaking" by requiring ratepayers to pay for past management mistakes. First of all, for the reasons discussed above, there were no "past management mistakes." Moreover, these settlement expenditures were prudent and represent a legitimate cost of preserving certain valuable hydroelectric facilities on the Spokane River. Even more to the point, Avista's settlement obligation to the Tribe could not have been anticipated or previously calculated for purposes of prior recovery through rates. As explained by witness Pessemier, "it is only with the advent of the settlement with the Tribe that the obligation has become established, and this general rate case provided the first opportunity for review and recovery of the costs associated with this obligation." (Id. at p.6, ll. 19-21)

172 Ultimately, a protracted mediation process resulted in the resolution of this matter. As explained by witness Pessemier, it involved the collection, exchange and detailed analysis of more than 20,000 pages of historical records and documents, required extensive participation by numerous experts and hundreds of pages of legal briefing and analysis. (Id. at p.17, ll. 5-13) The settlement discussions involved an experienced mediator and was assisted by the

non-binding advisory opinion of Judge Canby, a Senior Judge with the Ninth Circuit Court of Appeals, an acknowledged expert in the area of Indian law.

173 In the final analysis, the Settlement resolves disputed issues regarding more than 100 years of hydroelectric generation by Avista using Tribal lands, as well as for up to 50 years in the future (during the term of the remaining license), and resolved a number of other critical issues pertaining to Avista's relicensing efforts on the Spokane River, as well as providing for water rights, transmission rights-of-way, and other authorizations needed from the Tribe. In the end, the Settlement was "prudent, and represents a reasonable and fair compromise of disputed issues, and represents a legitimate cost to preserving a valuable, low-cost resource for the future benefit of our customers," as concluded by Ms. Pessemier. (Id. at p.3, ll. 11-13)

VI. CONCLUSION

174 Avista respectfully requests that this Commission approve the Settlement Stipulation, as filed. As demonstrated by the foregoing, the terms of the Settlement are lawful, and are supported by an appropriate record, and the end result is consistent with the public interest. It strikes a reasonable balance between the interests of Avista's customers, including its limited income customers and the Company, and would provide a measure of certainty regarding future cost recovery, which is an important element in improving the Company's financial health and improving its credit standing. It was the result of a compromise among differing interests and the "end result" will result in rates that are fair, just, reasonable and sufficient for purposes of this proceeding.

RESPECTFULLY SUBMITTED this ___ day of November, 2008.

AVISTA CORPORATION

By:______________________________

David J. Meyer
Vice President and Chief Counsel for Regulatory and Governmental Affairs

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