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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: T.W. Patch, Chairman
Kate Giard
Paul F. Lisankie
Robert M. Pickett
Janis W. Wilson

In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by ALASKA ELECTRIC LIGHT AND POWER COMPANY	)))))	U-10-29 ORDER NO. 15

ORDER ACCEPTING PARTIAL STIPULATION, DETERMINING REVENUE REQUIREMENT AND RATE DESIGN ISSUES, APPROVING PERMANENT RATES, AND APPROVING TARIFF SHEETS

BY THE COMMISSION:

Summary

We accept the unopposed partial stipulation filed in this matter. We determine the revenue requirement and rate design issues for Alaska Electric Light and Power Company (AEL&P).

Background

AEL&P filed TA381-1, requesting a 24 percent permanent across-the-board rate increase to base demand and energy charges.[1] This request was based upon a proposed revenue requirement of $43,135,748 and projected revenue deficiency of $15,827,289.[2] AEL&P asserted that this revenue deficiency justified a 59 percent increase in the base rates charged firm customers.[3] AEL&P proposed to mitigate this

[1]*Tariff Advice Letter No. 381-1*, filed May 3, 2010 (TA381-1), at 4.

[2]TA381-1 at 3; Revenue Requirement Study, Schedule 5.

[3]TA381-1 at 3.

increase by moving recognition of $3,461,863 of interruptible energy sales revenue from its cost of power adjustment (COPA) mechanism into base rate calculations; by including $3,191,898 of projected future interruptible energy sales revenue in base rate calculations; and by forgoing recovery of approximately $3,300,000 of its revenue requirement.[4] With these adjustments, AEL&P projected a total revenue deficiency of 22.1 percent,[5] or $5,873,528.[6] AEL&P has proposed recovering this revenue deficiency through the requested 24 percent increase in energy and demand charges, with no change to its customer charges.[7]

AEL&P requested an interim and refundable across-the-board demand and energy charge rate increase of 20 percent, effective for billings rendered after June 18, 2010, in the event that we suspend TA381-1 for further investigation.[8] TA381-1 included a cost-of-service study,[9] a revenue requirement study,[10] and proposed tariff sheets. AEL&P also submitted prefiled direct testimony of Timothy D. McLeod,[11] Constance S. Hulbert,[12] Thomas M. Zepp,[13] and David A. Gray.[14]

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[4]TA381-1 at 3-4.

[5]TA381-1 at 3.

[6]$15,827,289 - $3,461,863 - $3,191,898 - $3,300,000 = $5,873,528.

[7]*See* TA381-1 at 4.

[8]TA381-1 at 4.

[9]*Alaska Electric Light and Power Company Cost of Service Study*, filed May 3, 2010 (COSS).

[10]*Alaska Electric Light and Power Company Revenue Requirement Study*, filed May 3, 2010 (RRS).

[11]*Prefiled Direct Testimony of Timothy D. McLeod*, admitted May 10, 2011 (T-5 McLeod Direct).

[12]*Prefiled Direct Testimony of Constance S. Hulbert*, admitted May 11, 2011 (T-7 Hulbert Direct).

[13]*Prefiled Direct Testimony of Thomas M. Zepp*, admitted May 11, 2011 (T-9 Zepp Direct).

[14]*Prefiled Direct Testimony of David A. Gray*, admitted May 9, 2011 (T-1 Gray Direct).

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We issued public notice of the request.[15] We received a multitude of comments regarding this requested rate increase or requesting that a public hearing on this increase be held in Juneau before a decision on AEL&P's request was reached.[16] We held a consumer input hearing in Juneau on June 15, 2010, at which approximately fifty oral and written comments regarding AEL&P's proposed rate increase were received**.**[17]

We suspended TA381-1 into this docket and denied AEL&P's request for an interim rate increase.[18] We scheduled a hearing on AEL&P's request for an interim rate increase.[19] AEL&P submitted a brief on interim rate increase issues,[20] and an errata to TA381-1.[21] AEL&P employees Kenneth S. Willis, Hulbert, and McLeod testified at the interim rate increase public hearing.[22] With these witnesses, AEL&P introduced twenty-one exhibits into the record.[23]

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[15]*Notice of Utility Tariff Filing,* dated May 5, 2010.

[16]*See* Public comments, filed in TA381-1.

[17]*The transcript of this hearing can be viewed by following the link to our website and clicking on the "Documents" Tab:* http://rca.alaska.gov/RCAWeb/Dockets/DocketDetails.aspx?id=dfb6efef-bbb4-42a7-951d-6e1209b20ee0

[18]Order U-10-29(1), *Order Suspending TA381-1, Denying Request for Interim Rates, Scheduling a Hearing on Interim Rates, Scheduling a Prehearing Conference, Inviting Petitions for Intervention and Participation by the Attorney General, Addressing Timeline for Decision, Designating Commission Panel, and Appointing Administrative Law Judge*, dated June 17, 2010 (Order U-10-29(1)), at 2-6.

[19]Order U-10-29(1) at 6.

[20]*Alaska Electric Light and Power Company Interim Rate Relief Request Prehearing Brief*, filed July 6, 2010.

[21]*Errata to Tariff Advice No. 381-1*, filed July 6, 2010.

[22]Public Hearing, July 6, 2010. Tr. 30-87.

[23]Exhibits H-1 through H-21, admitted July 6, 2010. Tr. 24.

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We granted AEL&P a 20 percent interim and refundable rate increase, effective July 16, 2010.[24] The Attorney General (AG) elected to participate in this proceeding.[25] The Juneau Peoples' Power Project (J3P) petitioned to intervene in this proceeding.[26] AEL&P submitted corrections to TA381-1 and the prefiled testimony of Gray.[27] We granted J3P party status in this proceeding.[28]

J3P submitted prefiled testimony of Randall A. Sutak.[29] The AG submitted prefiled testimony of Janet K. Fairchild[30] and David C. Parcell.[31] The City and Borough of Juneau requested that we hold the hearing for this proceeding in Juneau.[32] We ordered that the hearing in this proceeding be held in Juneau.[33] AEL&P

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[24]Order U-10-29(2), *Order Granting Interim and Refundable Rate Increase, Approving Tariff Sheets and Requiring Filing*, dated July 16, 2010, as corrected by *Errata Notice to Order U-10-29(2)* (Order U-10-29(2)).

[25]*Notice of Election to Participate*, filed July 19, 2010.

[26]*Juneau Peoples' Power Project, Bill Burk, Vincent Hayden, John and Carolyn Martin, Randy Sutak, and Cheryl K. Moralez Joint Petition to Intervene*, filed July 19, 2010.

[27]*AELP's Errata to Tariff Advice No. 381-1*, filed August 13, 2010 (Second Errata). This errata also refers to changes to T-1 Gray.

[28]Order U-10-29(4), *Order Granting Petition to Intervene in Part, Requiring Filings, and Scheduling Prehearing Conference*, dated September 27, 2010.

[29]*Prefiled Direct Testimony of Randall A. Sutak*, admitted May 12, 2011 (T-13 Sutak Direct).

[30]*Prefiled Testimony of Janet K. Fairchild*, admitted May 12, 2011 (T-11 Fairchild Direct).

[31]*Prefiled Direct Testimony of David C. Parcell on Behalf of the Attorney General*: admitted May 12, 2011; Notice of Filing Errata to Prefiled Testimony of David Parcell admitted May 12, 2011(T-12 Parcell Direct). Both documents are admitted as one exhibit.

[32]Correspondence from L. Sica, Municipal Clerk, City and Borough of Juneau, filed February 3, 2011.

[33]Order U-10-29(9), *Order Modifying Procedural Schedule*, dated March 3, 2011.

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submitted prefiled reply testimony of McLeod,[34] Hulbert,[35] Zepp,[36] Gray,[37] Willis,[38] and Joseph Perkins.[39]

AEL&P submitted revised prefiled reply testimony of Willis[40] and Perkins.[41] AEL&P and the AG filed a stipulation between themselves resolving some of the issues raised in the testimony of Fairchild and Hulbert.[42] J3P did not oppose our acceptance of this stipulation.[43] The AG submitted corrections to the prefiled testimony of Parcell and Fairchild.[44] J3P submitted a correction to the prefiled testimony of Sutak.[45] The parties filed statements of issues.[46] J3P requested subpoenas for two additional witnesses.[47] On an expedited basis, we denied J3P's request for

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[34] *Reply Testimony of Timothy D. McLeod*, admitted May 10, 2011 (T-6 McLeod Reply).

[35] *Prefiled Reply Testimony of Constance S. Hulbert*, admitted May 11, 2011 (T-8 Hulbert Reply).

[36] *Reply Testimony of Thomas M. Zepp*, admitted May 11, 2011 (T-10 Zepp Reply).

[37] *Prefiled Reply Testimony of David A. Gray*, admitted May 9, 2011 (T-2 Gray Reply).

[38] *Prefiled Reply Testimony of K. Scott Willis*, filed March 4, 2011 (withdrawn on April 13, 2011).

[39] *Prefiled Reply Testimony of Joseph Perkins*, filed March 4, 2011 (withdrawn on April 13, 2011).

[40] *Prefiled Reply Testimony of K. Scott Willis (Revised 4/13/11)*, admitted May 9, 2011 (T-3 Willis Revised Reply).

[41] *Prefiled Reply Testimony of Joseph Perkins (Revised 4/13/11)*, admitted May 10, 2011 (T-4 Perkins Revised Reply).

[42] *Unopposed Partial Stipulation*, filed April 28, 2011 (Stipulation).

[43] *Settlement Report*, filed April 28, 2011 (Settlement Report), at 2.

[44] *Notice of Filing Errata to Prefiled Testimony of David A. Parcell*, filed May 2, 2011; *Notice of Filing Errata to* [Fairchild] *Prefiled Testimony*, filed May 2, 2011.

[45] *Errata of Randall A. Sutak's Testimony*, filed May 3, 2011.

[46] *Attorney General's Statement of Issues*, filed May 2, 2011; *AELP's Statement of Issues*, filed May 2, 2011; *Juneau Peoples' Power Project's Statement of Issues*, filed May 3, 2011.

[47] *Juneau Peoples' Power Project's Witness List and Request for Subpeona* [*sic*] *of Additional Witnesses*, filed May 3, 2011.

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subpoenas.[48] The public hearing in this proceeding was held in the City and Borough of Juneau Assembly Chambers on May 9 through 13, 2011. Additional oral public comment was received on the morning of May 10, 2011.[49] We also received additional written public comments.[50] With the consent of the parties, we extended the statutory deadline for issuance of a final order in this proceeding.[51]

Discussion

Acceptance of Stipulation Reducing Revenue Requirement

Before the hearing, AEL&P and the AG stipulated to a decrease in AEL&P's pro forma test year revenue requirement.[52] The stipulation proposed a reduction of both AEL&P's operating expenses and rate base. The reductions were based on proposed adjustments presented in AG witness Fairchild's testimony. Stipulated decreases to AEL&P's amortization expense, property tax allowance, bad debt expense, and miscellaneous expense result in a $292,259 reduction to operating expenses. Stipulated decreases associated with prepayments, deferred debt debit, and cash working capital allowance result in a $1,810,265 reduction to AEL&P's pro forma rate base. J3P, while not a signatory, does not object to the stipulation between AEL&P and the AG.[53]

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[48]Order U-10-29(12), *Order Accepting Late-Filed Documents, Denying Request for Subpoena of Additional Witnesses, and Granting Request for Expedited Consideration*, dated May 6, 2011.

[49]Tr. 381-394.

[50]Correspondence from B. Donnelly, filed May 2, 2011; Correspondence from H. Zimmerman, filed May 12, 2011.

[51]Order U-10-29(13), *Order Extending Statutory Timeline with Consent of Parties and Extending Tariff Suspension*, dated July 27, 2011. Order U-10-29(14), *Order Extending Statutory Timeline with Consent of Parties and Extending Tariff Suspension,* dated August 26, 2011.

[52]Stipulation.

[53]*Settlement Report*, filed April 28, 2011, at 2.

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Parties may stipulate among themselves to the resolution of issues outstanding in a proceeding.[54] If we accept the stipulation, the parties are bound by its terms. The stipulation between AEL&P and the AG proposed to reduce AEL&P's operating expenses and rate base. Further, the stipulation reduced the number of issues to be addressed at hearing and helped to conserve the parties' and the commission's time and resources. The prefiled testimony and exhibits relied on in the stipulation were admitted as evidence in this proceeding[55] and no party of record opposes our acceptance of the stipulation. Accordingly, we accept the stipulation, subject to the express condition that no issue shall be considered to have been finally determined or adjudicated by virtue of our acceptance of the stipulation. A copy of the stipulation is attached to this order as Appendix A.

Lake Dorothy Hydroelectric Project Prudence

One of the two main drivers behind AEL&P's requested rate increase is the increase in its hydroelectric costs due to the Lake Dorothy Hydroelectric Project (Lake Dorothy) project going into service.[56] J3P presented allegations asserting that AEL&P's decision to construct Lake Dorothy was not prudent.[57] The AG, who participates in our proceedings as a public advocate when he determines that participation is in the public interest,[58] presented no argument or evidence challenging

[54]3 AAC 48.166.

[55]Public hearings held July 6, 2010; May 9, 2011, through May 13, 2011 (admission of Exhibits H-1 through H-39, H-41 through H-43, H-45 through H-90, and T-1 through T-13).

[56]TA381-1 at 2.

[57]*See, e.g., Juneau People's Power Project's Statement of Issues*, filed May 3, 2011, at 1.

[58]AS 44.23.020(e).

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the prudence of AEL&P's decision to build Lake Dorothy. AEL&P responded with argument and evidence supporting the prudence of its decisions.[59]

The Federal Energy Regulatory Commission (FERC) has developed an approach for addressing challenges to the prudence of costs incurred by a utility. Under that approach, a utility's costs are presumed to be prudently incurred. It is up to the party challenging prudence to make a substantial showing that the challenged costs were imprudently incurred.

The approach taken by the FERC is consistent with prior decisions from the Alaska Public Utilities Commission (APUC), our predecessor agency. In addressing a challenge to expenses incurred by Kenai Pipe Line Company the APUC stated, "It is an extraordinary measure for a regulatory agency to entirely disallow costs that were actually and necessarily incurred to provide service. A disallowance of such costs would normally be made when the costs are imprudently incurred by the carrier."[60]

Based on this guidance, we will review the arguments and evidence presented by J3P to determine whether they have created a serious doubt as to the prudence of AEL&P's decision to construct Lake Dorothy (and therefore incur expenditures). A management decision is imprudent if a reasonable manager would not have made that decision.[61] Only if J3P has created a serious doubt will we then proceed to determine whether AEL&P has dispelled this doubt and proven the decision prudent.

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[59]T-3 Willis Revised Reply; T-4 Perkins Revised Reply; T-6 McLeod Reply at 2-6; T-8 Hulbert Reply at 2-10.

[60]Order P-91-2(11)/P-85-1(19), *Order Prescribing Rate Base Methodology; Resolving Other Disputed Issues; Directing Kenai Pipe Line Company to File Revised Revenue Requirement and Rates for Period Beginning June 1, 1991; Striking DR&R Testimony; Establishing Schedule for Phase II of this Proceeding; and Extending Suspension Period*, dated December 1, 1992 (Order P-91-2(1)), at 47.

[61]Order P-91-2(11) at 47.

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Evidence Regarding Prudence

J3P provided testimony that Hecla Greens Creek Mining Company (Greens Creek) was purchasing more interruptible, or excess, energy per year than Lake Dorothy was budgeted to produce.[62] J3P asserts that this is evidence that Lake Dorothy is not used and useful for AEL&P's firm customers, and thus Lake Dorothy costs should not be recoverable through rates charged firm customers.[63]

AEL&P presented evidence that its decision to develop Lake Dorothy was prudent. One of the exhibits presented by AEL&P was the *Juneau 20 Year Power Supply Plan*, dated December 1984.[64] This power supply plan discussed load growth projections and power supply options available for the Juneau area. The plan found that construction of Lake Dorothy had several advantages over other potential generation resource additions.[65] AEL&P also introduced the 1990 *Juneau 20-Year Power Supply Plan Update*.[66] This update identified Lake Dorothy as the lowest-cost generation option over its life rotation.[67] The 1990 update recommended proceeding with the FERC process for licensing Lake Dorothy.[68] AEL&P received a FERC preliminary permit for Lake Dorothy in 1996.[69] AEL&P received a FERC license authorizing construction of Lake Dorothy in 2003.[70]

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[62]T-13 Sutak Direct at 5.

[63]T-13 Sutak Direct at 5.

[64]Exhibit H-3.

[65]Exhibit H-3, Section 6 at 2-4.

[66]Exhibit H-4.

[67]Exhibit H-4, Section ES at 3-4.

[68]Exhibit H-4, Section VI at 3-4.

[69]Tr. 43; Exhibit H-2; T-3 Willis Revised Reply at 7, KSW-5.

[70]Tr. 43; Exhibit H-2; T-3 Willis Revised Reply at 7, KSW-5.

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AEL&P introduced a 2006 consulting engineer's report prepared by CH2MHill for AEL&P and the Alaska Industrial Development and Export Authority (AIDEA).[71] The report reviewed AEL&P's load forecast and existing generation resources.[72] Further, the engineer's report investigated the Lake Dorothy design, output projections, economic projections, and risks.[73] CH2MHill found that the Lake Dorothy design and projections were reasonable and that the risks were prudently accounted for.[74]

AEL&P projects that production by Lake Dorothy will reduce the scheduled use of diesel generation by 77 hours, from 113 hours to 36 hours, in an average water year.[75] AEL&P estimates that this reduced use of diesel generation will result in annual savings of approximately $8,504 on diesel generator overhaul costs.[76] AEL&P estimated that Lake Dorothy would, on average, reduce the amount of annual diesel generation by 3,318,405 kWh.[77] AEL&P estimates that, at the March 3, 2011, price of $3.54/gallon of diesel, this would reduce the amount of annual diesel purchases by $903,627.[78] Total Lake Dorothy output was estimated to be 74,500,000 kWh during an average water year, and 62,800,000 kWh during a dry year.[79]

After reviewing the assertions presented by J3P, we are unable to find that J3P presented a showing of inefficiency or improvidence sufficient to raise a serious

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[71]Exhibit H-5.

[72]Exhibit H-5 at 3-18.

[73]Exhibit H-5 at 18-39.

[74]Exhibit H-5 at 40.

[75]Exhibit H-47; H-62 at 1.

[76]Exhibit H-62 at 1.

[77]T-8 Hulbert Reply, CSH-4.

[78]T-8 Hulbert Reply at 3.

[79]Exhibit H-5 at 20.

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doubt as to AEL&P's prudence in developing Lake Dorothy. Further, AEL&P has made a sufficient showing that its decision to construct Lake Dorothy was prudent.

Lake Dorothy Construction Management Prudence

The estimated construction cost for Lake Dorothy was $53.5 million.[80] The final cost was $78.5 million.[81] J3P alleges that AEL&P's construction management of Lake Dorothy was inconsistent with prudent utility practice, resulting in the final costs exceeding the original budget by $20 million.[82] The AG presented no argument or evidence challenging the prudence of AEL&P's construction management.

Challenges to cost overruns incurred on a construction project are reviewed based on a similar standard to the prudence standard articulated above. The APUC addressed construction cost overruns in Order U-83-53(32).[83] In that decision the APUC addressed alleged imprudent or unnecessary costs incurred on a construction project. The alleged imprudent or unnecessary costs were tied to a design error. The APUC stated that recovery for imprudent or unnecessary costs should be disallowed.[84] However, they denied the prudence challenge and allowed the recovery of costs based on a finding that the amount of the cost overrun attributable to the design error was difficult to quantify and that the record was insufficient to support a finding of imprudence.[85] The APUC's approach is consistent with the FERC prudence standard identified above. Therefore, we conduct our review of the challenge to the prudence of AEL&P's construction management using the same standard articulated above.

[80]Exhibit H-5 at 30.

[81]T-4 Perkins Revised Reply at 5.

[82]T-13 Sutak Direct at 2.

[83]Order U-83-53(32), *Order Deciding Substantive Revenue Requirement Issues and Requiring Permanent Rate and Applicable Refund Determinations*, dated December 4, 1986 (Order U-83-53(32)), at 13-16.

[84]Order U-83-53(32) at 15.

[85]Order U-83-53(32) at 15-16.

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J3P asserts that the cost overrun for Lake Dorothy was due to imprudent construction management practices.[86] J3P specifically alleges that cost overruns resulted from AEL&P converting a low bid contract to a cost plus contract,[87] AEL&P's failure to prorate the materials portion of equipment repairs,[88] AEL&P's use of a project manager who was not a licensed engineer,[89] AEL&P's use of plans that had not been stamped by a professional engineer,[90] AEL&P's payment for conjugal visits for the benefit of contractor employees,[91] and AEL&P's failure to order steel for the project before prices increased.[92]

AEL&P disputed these assertions with the testimony of Joseph Perkins.[93] Perkins found that five specific components of the project accounted for $23.8 million of the $25 million cost overrun.[94] With the exception of the change from gasketed steel penstock to welded steel penstock and the increase in steel prices,[95] the site conditions resulting in these cost overruns were identified as known risks in the pre-construction consulting engineer's report.[96] Perkins testified that some of the design changes related to changed site conditions were required by the FERC Board of Consultants and the resulting additional costs could not be avoided.[97] Unanticipated increases in the

[86]T-13 Sutak Direct at 9-12.
[87]T-13 Sutak Direct at 9-10.
[88]T-13 Sutak Direct at 9.
[89]T-13 Sutak Direct at 10.
[90]T-13 Sutak Direct at 10-11.
[91]T-13 SutakDirect at 11.
[92]T-13 SutakDirect at 12.
[93]T-4 Perkins Revised Reply, Tr. 451-479.
[94]T-4 Perkins Revised Replyat 5.
[95]T-4 Perkins Revised Reply at 7.
[96]Exhibit H-5 at 29-30.
[97]Tr. 475-476.

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price of steel for transmission towers and the cost of transportation apparently caused some portion of the remaining cost overrun.[98]

Perkins testified that the lack of detailed field investigation of site conditions before construction contributed to the low estimate, but did not significantly contribute to increased construction costs.[99] Specifically, he testified that if a detailed geotechnical investigation had been conducted, the project design and corresponding cost estimate would have been revised to reflect substantially what was actually constructed.[100] He also testified that conducting the additional geotechnical investigation at Lake Dorothy would have been extremely expensive.[101] Perkins concluded that, based upon the substantial geotechnical information available regarding the Lake Dorothy project, it was prudent for AEL&P to proceed with project construction without incurring the expense of conducting further geotechnical investigation.[102] He also testified that AEL&P's conversion of fixed price contracts to cost-plus contracts was prudent due to the changed conditions encountered during the construction of Lake Dorothy.[103]

In response to J3P's specific allegations of mismanagement, Perkins testified that it was not unusual for competent project managers to not be professional engineers and offered his professional opinion that Lake Dorothy was a well managed project.[104] Perkins testified that it would be unusual for project owners such as AEL&P

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[98]Tr. 109-111.

[99]T-4 Perkins Revised Reply at 9-11.

[100]T-4 Perkins Revised Reply at 9.

[101]T-4 Perkins Revised Reply at 9.

[102]T-4 Perkins Revised Reply at 9-13.

[103]T-4 Perkins Revised Reply at 17-20.

[104]T-4 Perkins Revised Reply at 20-21; Tr. 478.

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to purchase raw steel in advance of a construction project.[105] Perkins also testified AEL&P's use of unstamped plans did not cause any construction problems.[106] AEL&P witness Willis testified that AEL&P did not pay for conjugal visits to contractor employees.[107]

J3P extensively cross-examined AEL&P witnesses Willis and Perkins.[108] After reviewing the assertions presented by J3P regarding AEL&P's construction management and the responses of Willis and Perkins on cross-examination, we are unable to find that J3P presented a showing of imprudence sufficient to raise a serious doubt as to AEL&P's construction management. Further, AEL&P has made a sufficient showing that its construction management practices were prudent.

<u>Price Charged Greens Creek for Interruptible Energy</u>

AEL&P entered into an interruptible power sale agreement with Greens Creek in October 2005.[109] We approved the Greens Creek PSA in October, 2005.[110] J3P asserts that the Period 1 rate discount provided to Greens Creek pursuant to the Greens Creek PSA was unreasonably preferential to Greens Creek.[111] The Period I rates were implemented when interruptible energy sales to Greens Creek began in September 2006[112] and expired pursuant to the terms of the Greens Creek PSA two

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[105]T-4 Perkins Revised Reply at 21-22.

[106]T-4 Perkins Revised Reply at 23-24.

[107]T-3 Willis Revised Reply at 20.

[108]Tr. at 325-437 (Willis), 451-468 (Perkins).

[109]T-11 Fairchild Direct, JKF-11, *Agreement for the Sale and Purchase of Interruptible Energy Between Alaska Electric Light and Power Company and Kennecott Greens Creek Mining Company*, effective October 3, 2005 (Greens Creek PSA).

[110]Letter Order No. L0500581, dated October 4, 2005 (L0500581), in TA334-1.

[111]T-13 Sutak Direct at 7-8; Greens Creek PSA at 5, 10, Exhibit D.

[112]TA347-1, Exhibit 3.

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months later.[113] Pursuant to the prohibition on retroactive rate making, there appears to be no action that we could take regarding the Period I rates charged Greens Creek, even if we agreed with J3P's assertion.[114]

J3P also asserts that the price charged under the Greens Creek PSA for Period 3 interruptible energy is unreasonably low.[115] The AG evaluated the price for interruptible power charged by AEL&P to Greens Creek and compared it with the interruptible rate offered by another electric utility, Municipality of Anchorage d/b/a Municipal Light & Power (ML&P).[116] According to the AG, both utilities offer interruptible service at a discount from their rate for firm service. The AG determined that AEL&P offers less of a discount for interruptible service, on a percentage basis, than ML&P. Therefore, the AG determined that the Period 3 rate charged to Greens Creek is reasonable.

Based upon our examination of the Greens Creek PSA, we find that the cost of Lake Dorothy energy was intended to serve as a proxy price for all Period 3 energy sold to Greens Creek.[117] This proxy price was capped at $0.10/kWh for the first seven years of Lake Dorothy commercial operation.[118] For interruptible energy, our standard has been that prices must cover all incremental costs of generating the energy, plus a margin.[119] The estimated total annual cost of Lake Dorothy included

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[113]T-3 Willis Revised Reply at 9.

[114]*Matanuska Electric Ass'n, Inc. v. Chugach Electric Ass'n, Inc.*, 53 P.3d 578, 583-587 (Alaska 2002).

[115]T-13 Sutak Direct at 7-8; Greens Creek PSA at 5, 11, Exhibit D.

[116]T-11 Fairchild Direct at 41-42.

[117]Greens Creek PSA at 37-38

[118]Greens Creek PSA at 34-35.

[119]*See* Order U-93-94(2), *Order Approving Contract and Closing Docket*, dated May 9, 1994 (Order U-93-94(2)), Appendix at 10 (discussing typical pricing for interruptible energy contracts).

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approximately $400,000 in operating and maintenance costs[120] that do not appear fixed, and thus could be considered variable.[121] At a projected average annual output of 74,500,000 kWh,[122] Lake Dorothy variable costs would be less than $0.01/kWh.[123] The $0.10/kWh Greens Creek is paying AEL&P for interruptible energy substantially exceeds Lake Dorothy average variable costs. Therefore, we find that the Period 3 rate AEL&P charges Greens Creek for interruptible power is reasonable.

Lake Dorothy Allowance For Funds Used During Construction (AFUDC)

The reply testimony of AEL&P witness Hulbert summarizes the forty-year history of the regulatory use of an "Allowance For Funds Used During Construction" (AFUDC).[124] AFUDC came into use in jurisdictions such as ours, which do not permit a utility engaged in a multi-year construction project to include those costs in rates incrementally each year. Instead, those costs are reflected in rates after the completion of the project. AFUDC was therefore developed as an annual estimate of the utility's finance costs related to an ongoing construction project.[125] Upon project completion those annual AFUDC amounts are added to the other costs of the project for inclusion in the utility's rate base and then recovered through rates.[126]

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[120] Exhibit H-5 at 30-31 ($374,063 in 2009 with 3 percent inflation factor).

[121] *See* Order U-93-94(2), Appendix at 10.

[122] Exhibit H-5 at 20 (expressed as 74.5 gWh).

[123] $400,000 per year divided by 74,500,000 kWh per year = $0.0054/kwh.

[124] T-8 (Hulbert Reply) at 39 – 43.

[125] Construction of Phase I of the Lake Dorothy Hydro Project began in May 2006 and the project was not declared operational until August 2009. T-3 (Willis Reply), KSW-5 at 2.

[126] "When utilities are not allowed to earn a return to cover their construction financing costs during the construction period, they are allowed to capitalize the financing costs for future recovery through an allowance for funds used during construction (AFUDC)." T-8 (Hulbert Reply) at 41-42 *citing* Hahne, Accounting for Public Utilities at 4.04[4].

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Our regulations provide for the calculation of AFUDC by reference to the rules of the Federal Energy Regulatory Commission (FERC). Specifically, our regulations refer to the FERC uniform system of accounts in effect as of January 1, 1982.[127] The AFUDC-relevant part of that uniform system of accounts is found in 18 C.F.R. Part 101, Electric Plant Instructions. Paragraph 3 of the FERC uniform system of accounts states in part:

> (17) *Allowance for funds used during construction* (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, *not to exceed*, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.[128] (Emphasis added.)

Subparagraph (a) of Paragraph 3(17) sets out the general formula for calculating AFUDC. Subparagraph (b) of Paragraph 3(17) requires annual updating. The FERC adopted Order No. 561 in 1977, further explaining its interpretation of this regulation.[129]

AEL&P's proposed 2009 test year revenue requirement included a proposed return of $11,685,832 on an average rate base of $112,471,918.[130] This rate base included a total AFUDC of $9,365,205 for the Lake Dorothy Hydro project.[131] Hulbert testified AEL&P precisely followed the prescribed formula for calculating AFUDC. She believed the formula is intended to be a practical, standardized methodology for calculating AFUDC. Each of AEL&P's annual AFUDC calculations was

[127] 3 AAC 48.277(a)(10).

[128] 18 C.F.R. Part 101, Electric Plant Instructions, at ¶3(17).

[129] Exhibit H-63.

[130] RRS, Schedule 5.

[131] T-11 (Fairchild Direct) at 26, JKF-6, JKF-9.

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reviewed by accounting firm KPMG and then included in AEL&P's audited financial statements.[132]

Fairchild acknowledged that Paragraph 3(17) applied to AEL&P's AFUDC calculations and did not assert that AEL&P had incorrectly calculated the AFUDC for the Lake Dorothy hydro project when using the formula under the FERC uniform system of accounts.[133] Nonetheless, the AG disputed the manner in which AEL&P had calculated AFUDC. The AG asserted that the "not to exceed" language in the instruction quoted above indicates we have discretion to reduce the amount of AFUDC (for a specific project) below that which would otherwise be calculated using the general formula of the FERC uniform system of accounts.[134] The AG further asserted that use of our discretion would be appropriate here because certain bond funds used to finance the project were readily distinguishable. Using the general formula under the FERC uniform system of accounts to calculate the AFUDC amounts, the AG argued, overstated the Lake Dorothy construction financing costs actually incurred.[135]

Fairchild therefore recommended an alternative calculation methodology that would reduce the total AFUDC for the Lake Dorothy hydro project to $5,850,106.[136] The AG proposed that the AFUDC should be re-calculated using first the amount and lower interest rate[137] of the AIDEA conduit bonds[138] AEL&P had used to partially finance the project. Only after project spending exceeded the full amount of those funds

[132]T-8 (Hulbert Reply) at 39 – 40.

[133]T-11 (Fairchild) at 27-28, JKF-7.

[134]T-11 (Fairchild) at 27-29.

[135]T-11 (Fairchild) at 28.

[136]T-11 (Fairchild) at 28-29, JKF-9.

[137]$46,655,000 at 5.05 percent interest rate. T-11 (Fairchild Direct) at 28.

[138]AIDEA agreed to lend AEL&P up to $60 million for construction of Lake Dorothy by issuing tax exempt conduit revenue bonds. Exhibit H-36 at 2-3, Exhibit H-37 at 2-3.

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should subsequent AFUDC calculations have been calculated taking into account the higher costs[139] of other sources of funds used including AEL&P's equity contributions.[140]

Hulbert testified that FERC Order No. 561[141] provides the FERC-approved guidance for calculating AFUDC under the uniform system of accounts.[142] Hulbert also testified that as recently as 2007 the FERC has rejected requests (similar to the AG's current proposal) seeking to calculate AFUDC based upon the actual finance costs of the specific funds used to construct a particular project rather than using the general formula under FERC Order No. 561.[143] Hulbert also testified that AEL&P's calculations actually understated the AFUDC slightly since AEL&P had used the correct average interest rate paid on the AIDEA bonds (5.046 percent) but failed to include an amortization of the issuance premiums also paid on the AIDEA bonds.[144]

Through our regulations we have adopted a FERC methodology for calculating AFUDC prescribing the use of a specific formula. It is undisputed that the FERC instructions describe the formula AFUDC amount as a ceiling that a utility may not exceed "without prior approval" of the FERC. The implications of that prior approval requirement need to be addressed before any consideration of the AG's argument that

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[139]It is undisputed that the general AFUDC formula uses the average cost of all debt and the last authorized return on equity. It was also undisputed that in AEL&P's case average cost of debt was 5.30 percent and return on equity was 13 percent.

[140]T-11 (Fairchild) at 28; Tr. 287-288.

[141]Exhibit H-63 (copy of FERC Order No. 561).

[142]Tr. 716-718.

[143]Tr. 717-723.

[144]Tr. 641-644, 734-735.

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the discretion to permit AFUDC exceeding the formula[145] amount implies the discretion to order an amount less than that calculated under the formula.

As previously noted AFUDC is calculated annually as an estimate of the costs incurred to finance a multi-year construction project. It is necessarily calculated by the utility outside of the rate setting context in jurisdictions such as ours that do not permit rate recovery of costs before a project is completed and becomes "used and useful" in providing utility service. Having a "pre-approved" method of calculation that a utility is generally bound to use therefore makes sense. Because the calculated AFUDC amounts need to be reviewed and included in annual audited financial statements, it also makes sense that any departure from that generally applicable "pre-approved" method of calculation would need to be approved in advance by the regulator. Otherwise the utility, its auditor, and investors relying upon those audited financial statements could not be certain that the calculations were acceptable to the regulator rather than simply "arithmetically correct."

The AG's current proposal raises similar concerns in reverse. Accepting the proposition that we may recalculate AFUDC amounts years later, that possibility would unavoidably reduce the audit process to a math review and introduce an additional degree of regulatory uncertainty. While we received no evidence on the possibility that the utility's financial statements might need to be re-stated, the imposition of additional regulatory uncertainty in the absence of compelling reasons is not a result we prefer. The AG did not comment upon this aspect of the proposal or why it would be preferable to requiring both the utility (if it seeks a higher than standard

[145]Since we have adopted their rule the FERC's interpretations of it are certainly worthy of our consideration though we might not necessarily consider ourselves bound to reach an identical result. Consequently, we appreciated AEL&P's testimony and submission of orders demonstrating the FERC's apparent unwillingness to grant requests for approval of AFUDC amounts exceeding those calculated using the formula.

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AFUDC amount) and any challenger such as the AG (if it seeks a lower than standard AFUDC amount) to obtain prior approval. For this reason we decline to order recalculation of the otherwise correct AFUDC amounts and reject the AG's proposed AFUDC adjustment to the 2009 revenue requirement study filed by AEL&P. We will include the entire AFUDC amount calculated by AEL&P in its current rate base.[146]

Adjustments for Addition of Lake Dorothy

AEL&P asserts that Lake Dorothy went into commercial service on August 31, 2009.[147] AEL&P is requesting a rate increase based upon its proposed 2009 test year revenue requirement of $43,135,748.[148] This amount includes proposed normalizing adjustments proposed by AEL&P to reflect a full year of Lake Dorothy operations.[149] This also includes an AEL&P proposed normalizing adjustment to rate base so as to account for Lake Dorothy being classified as plant in service for the entire year.[150] AEL&P asserted that these normalization adjustments were justified under the

[146]Even if we were to review the AFUDC calculations now we would have doubts about the reasonability of the AG's proposal. AEL&P made a $6,771,451 equity investment in the Lake Dorothy project as a pre-condition for obtaining the AIDEA funds. Tr. 178-179; RRS at 3. It had also accumulated an additional $9 million in pre-loan cash to spend on the project in addition to its planned expenditure of $8 million from retained earnings. Exhibit H-36 at 3. The AG's proposed Lake Dorothy AFUDC calculation methodology would seemingly prevent AEL&P from earning a reasonable return on its equity investment in Lake Dorothy during the construction period.

[147]T-5 McLeod Direct at 10; T-7 Hulbert Direct at 7-8; Tr. 55, 91.

[148]RRS at 8.

[149]*See* T-7 Hulbert Direct at 7-8.

[150]RRS at 21 (proposing $41,594,583 increase to 13 month average plant in service).

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Commission's decisions in Orders U-01-108(26)[151] and U-08-157(1),[152] because Lake Dorothy would be in operation during the time the rates established in this docket will be in effect.[153]

AEL&P witness Willis testified that energy production from Lake Dorothy was temporarily halted on March 8, 2010, so as to drain Bart Lake and resolve a seepage problem.[154] Energy production was expected to resume on or about July 20, 2010.[155] We authorized an interim and refundable rate increase for AEL&P, effective July 16, 2010.[156]

The AG opposed the Lake Dorothy normalization adjustments, primarily based on an asserted lack of synchronization between these adjustments and the remainder of AEL&P's revenue requirement.[157] In arguing against AEL&P's Lake Dorothy normalization adjustments, the AG distinguished Lake Dorothy from the plant additions at issue in Orders U-01-108(26) and U-08-157(10).[158] The AG particularly

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[151]Order U-01-108(26), *Order Determining Revenue Requirement and Rate Design Issues and Requiring Filings*, dated January 31, 2003 (Order U-01-108(26)).

[152]Order U-08-157(1)/U-08-158(1), *Order Consolidating Dockets, Suspending Tariff Filings, Granting Interim and Refundable Rates, Approving Tariff Sheets, Establishing Interest Rate on Refunds, Requiring Filing, Inviting Participation by the Attorney General, and Intervention, Addressing Timeline for Decision, Scheduling Prehearing Conference, Designating Commission Panel, and Appointing Administrative Law Judge*, dated December 29, 2008. Based upon the context in which this citation is placed, it appears that AEL&P meant to cite to Order U-08-157(10)/U-08-158(10), *Order Resolving Revenue Requirement Issues*, dated February 11, 2010, (Order U-08-157(10)) at 26-28.

[153]T-7 Hulbert Direct at 8.

[154]T-4 Willis Revised Reply at 12; *See* Tr. 91-97.

[155]Tr. 97-98.

[156]Order U-10-29(2) at 11.

[157]*See* T-11 Fairchild Direct at 28-32.

[158]T-11 Fairchild Direct at 30-31.

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found significant that Lake Dorothy had been taken out of service from March to July of 2010.[159] The AG also objected on the ground that AEL&P had not removed from its rate base any plant that had been retired during or after the test year.[160] The AG recommended elimination of the proposed Lake Dorothy normalizations, reducing AEL&P's revenue requirement by $5,916,589 and projected revenue by $3,191,898.[161]

AEL&P disputed the AG's interpretation of Orders U-01-108(26) and U-08-157(10).[162] AEL&P witness Willis testified that even with Lake Dorothy power production being off-line for the March to July period, total production for the first twelve-months of operation was 95 percent of the predicted annual output.[163] AEL&P and the AG subsequently stipulated to inclusion of AEL&P's proposed Lake Dorothy operator expense normalization in AEL&P's revenue requirement.[164]

A revenue requirement is supposed to include test year operating revenues and expenses, adjusted to represent a normalized test year.[165] The term "normalized test-year" is defined as: "a historical test-year adjusted to reflect the effect of known and measureable changes and to delete or average the effect of unusual or nonrecurring events, for the purpose of determining a test year which is representative of normal operations in the immediate future."[166]

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[159]T-11 Fairchild direct at 29-31.

[160]T-11 Fairchild Direct at 30, 32.

[161]T-11 Fairchild Direct at 32, JKF-2.

[162]T-8 Hulbert Reply at 19-23.

[163]T-3 Willis Revised Reply at 13.

[164]Stipulation at 3.

[165]3 AAC 48.275(a)(5), (6), (7), (8).

[166]3 AAC 48.820(42).

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Normalization adjustments have been made to utility revenue requirements in Alaska since at least 1967.[167] Our predecessor, the APUC found in 1980 that:

> The Commission may not, however, confine its analysis simply to the results for 1979. An essential element in establishing permanent rates is the determination of appropriate "normalization adjustments" for "known and measurable changes" which should be made to the results of operations for the test year selected by the Commission, *See, e.g., Re United Gas Pipeline Company*, 54 PUR 3d 285, 291 (FPC 1964).[168]

Regarding new plant in service, ML&P conducted pre-commercial operation testing of its new waste steam generator during the 1983 coincident peak gas usage period on the ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. (ENSTAR) system, substantially skewing ENSTAR's cost-of-service study.[169] ENSTAR proposed treating the steam unit as if it were not functional during the test year.[170] The APUC found this proposal to be unreasonable, but also found treating the steam unit as if it had been functional all year was unreasonable.[171] Based upon the evidence available, the APUC ordered a normalization adjustment to ENSTAR's load data to reflect the steam unit being functional 50 percent of the year.[172]

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[167]Order U-66-8(2), *Order Adopting in Part and Modifying in Part the Decision of the Hearing Officer*, dated June 23, 1967, at 3-7.

[168]Order U-80-27(1), *Order Affirming Bench Order*, dated May 9, 1980, at 8.

[169]Order U-83-38(6), *Order Approving Tariff Revision, in Part; Requiring Revisions of Cost of Service Study and Rate Redesign; Approving Sequence of Interruptions; and Establishing Methodology for Allocating Costs Resulting from Interruptions of Service*, dated February 14, 1984 (Order U-83-38(6)), at 7-8.

[170]*See* Order U-83-38(6) at 8-9.

[171]Order U-83-38(6) at 9.

[172]Order U-83-38(6) at 9-10.

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In considering normalization adjustments for plant brought into service during or after the revenue requirement test year, we have been concerned about ensuring that adjustments reflecting both the costs and the benefits of the new plant are accounted for, i.e., that the adjustments are synchronized. Synchronization has been defined as:

> The proper matching or balancing of operating expenses (including depreciation and taxes), rate base, and revenue (in this case, revenue is expressed through demand units). The expectation is that the relationships from the test period will hold reasonably constant during the period that rates will be in effect. Any change in those relationships could result in the under-recovery or over-recovery of an approved revenue requirement.[173]

For example, during calendar year 2003 Golden Valley Electric Association, Inc. (GVEA) completed construction of the Northern Intertie Transmission Project from Healy to Fairbanks, and the Battery Energy Storage System (BESS).[174] GVEA filed a revenue requirement study based on a 2003 calendar year test year,[175] and requested a normalization adjustment to annualize depreciation expense for this new plant.[176]

We rejected GVEA's requested normalization adjustment because it was not synchronized with other adjustments that would have been required for the revenue requirement to truly reflect full year operation of the plant.[177] Specifically, GVEA's

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[173]Order U-91-32(1), *Order Opening Dockets; Affirming Hearing and Filing Schedules; and Appointing Hearing Officer*, dated June 24, 1991, Appendix, at 14.

[174]*See* Order U-04-33(10), *Order Granting GVEA Authority to Implement Simplified Rate Filing Procedures; Granting GVEA's Request to Adjust Rates, in Part; Requiring Filing; and Affirming Electronic Rulings*, dated May 31, 2005 (Order U-04-33(10)), at 6-7.

[175]*See* Order U-04-33(10) at 5.

[176]Order U-04-33(10) at 6-7.

[177]Order U-04-33(10) at 7.

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proposed adjustment was rejected because it was not synchronized with adjustments for the operations and maintenance expense of the new plant and with adjustments reflecting the benefits of this new plant.[178] A significant reason for rejecting GVEA's proposed depreciation expense normalization adjustment was that GVEA was in the SRF program, and would be filing a new simplified revenue requirement in just six-months that could be based upon actual costs and benefits related to this new plant.[179]

However, in Order U-01-108(26), to which both AEL&P and the AG cited, we allowed normalization adjustments to Chugach's 2000 test year revenue requirement for the Beluga 6 and 7 repowering projects that were not completed until October, 2001.[180] In doing so, we noted that those projects would be operational during the time rates established in that proceeding would be in effect and would result in improved fuel efficiency that would benefit consumers immediately through Chugach's cost of power adjustment (COPA) mechanism.[181] We also noted that the Beluga 6 and 7 normalization adjustments were "exhaustively" reviewed during the rate case litigation,[182] and concluded:

> To reject these adjustments exclusively because they are out-of-period adjustments now would require Chugach to file for rate relief immediately. A lengthy and costly rate proceeding would surely ensue, but the evidentiary record would likely mirror the one just developed in this proceeding.

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[178]Order U-04-33(10) at 7 (Although not specifically identified in the Commission's decision, the Northern Intertie relieved a transmission constraint between Healy and Fairbanks, allowing GVEA to purchase an additional 25 MW of lower cost power from Chugach Electric Association, Inc. (Chugach) or ML&P. BESS allowed GVEA to reduce its spinning reserve requirements by 27 MW. In combination, these two plant additions should have substantially decreased GVEA's fuel cost, but increased purchase power expense, operations expense, and maintenance expense.).

[179]Order U-04-33(10) at 6-7.

[180]Order U-01-108(26) at 59-64.

[181]Order U-01-108(26) at 60.

[182]Order U-01-108(26) at 63-64.

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. . . .

> We must balance the difficulty in synchronizing the revenue requirement for Chugach's adjustments for activity beyond the test period with the costs associated (and ultimately borne by ratepayers) with a new revenue requirement filing. In this case, the scales tip in favor of allowing Chugach the out-of-period adjustments.[183]

In Order U-08-157(10), to which both AEL&P and the AG also cite, we allowed AWWU to include a normalization adjustment to its 2007 test year revenue requirement based upon new plant placed into service in October 2007.[184] That normalization was allowed based upon a finding that the plant costs were known and measureable, the plant would be in service during the period of time rates determined in that proceeding would be in effect, and there were no synchronization problems with the benefits of the plant.[185]

Lake Dorothy apparently went into permanent service on or about July 20, 2010, and the interim rate increase authorized in this proceeding could have gone into effect no earlier than July 16, 2010. Thus, for all practical purposes, Lake Dorothy will be in service during the period of time rates established in this proceeding have been or will be in effect. The capital costs of Lake Dorothy are known and measureable and were litigated extensively in this proceeding. The primary operation cost related to Lake Dorothy appears to be labor cost related to the project operator, and the AG has already stipulated to include an annualized normalization adjustment to AEL&P's revenue requirement for this expense. AEL&P is proposing a normalization adjustment to revenue reflecting a full year's worth of anticipated revenue from sales of Lake Dorothy energy to Greens Creek. The other anticipated benefit of Lake Dorothy would be a

[183]Order U-01-108(26) at 64.

[184]Order U-08-157(10) at 4, 26-28.

[185]Order U-08-157(10) at 28.

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reduction in diesel fuel consumption, which will be returned to consumers through AEL&P's COPA mechanism.

There appears to be no material synchronization problem with accepting AEL&P's proposed Lake Dorothy normalization adjustments in this docket. If those adjustments are rejected for being out of time, AEL&P would probably immediately file a new revenue requirement study given the magnitude of the proposed Lake Dorothy adjustments compared to AEL&P's revenue requirement. The public interest would not be served if we were to force AEL&P to immediately file a new rate case. For the reasons stated in Order U-01-108(26) quoted above, we accept AEL&P's proposed Lake Dorothy normalization adjustments. This produces a rate base of $110,661,653 for AEL&P.[186]

Cost of Power Adjustment (COPA)

AEL&P projects selling an average of 66,525,705 kWh of interruptible power per year to Hecla Greens Creek Mining Co. (Greens Creek) pursuant to the Greens Creek Power Sales Agreement (PSA) based on Greens Creek average consumption over the past three years.[187] The current price Greens Creek pays for interruptible power under this special contract is $0.10 per kWh plus a $99.24 per month customer charge.[188] As part of its revenue requirement proposal under consideration here AEL&P has reduced the revenues to be paid by its firm customers by including in base rate calculations an estimated annual revenue from interruptible power sales to

[186]This figure is arrived by reducing the $112,471,918 pro forma rate base with Lake Dorothy adjustment (H-20, Revenue Requirement Study at 47) by the stipulated rate base adjustment of $1,810,265 (Stipulation at 3-4).

[187]T-7 Hulbert Direct at 5.

[188]T-7 Hulbert Direct at 5.

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Greens Creek in the amount of $6,653,761, calculated as [(66,525,705 kWh X $0.10 per kWh) + ($99.24 per month X 12 months)].[189]

However, AEL&P also seeks to protect itself from downward variations in sales to Greens Creek and provide its customers with the benefit of upward variations in sales to Greens Creek.[190] Specifically, AEL&P proposes to adjust its COPA balancing account on a monthly basis by the amount that revenue from sales to Greens Creek are greater or less than $554,480 for that month.[191] This monthly amount is calculated by dividing $6,653,761 by 12.[192] The details of AEL&P's proposal are set forth in the proposed revised Tariff Sheet Nos. 168, 169, 170, and 171, attached to TA381-1 under the heading "Permanent Rates".

The AG has agreed with this proposed treatment of Greens Creek sales revenues.[193] J3P disagrees with this proposal claiming it unreasonably shifts the risk of downward sales variations from AEL&P's owners to AEL&P's firm customers.[194]

The Greens Creek PSA was submitted for our approval in 2005 as TA334-1. It was approved in letter order L0500581. The rate charged for energy delivered to Greens Creek after the Lake Dorothy Project began commercial operation was set at the fully allocated cost of Lake Dorothy Project energy, or $0.10/kWh, whichever was lower.[195] In 2005, AEL&P estimated average sales to Greens Creek would be 60,000,000 kWh/year.[196]

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[189] T-7 Hulbert Direct at 5.

[190] T-7 Hulbert Direct at 5-6.

[191] T-7 Hulbert Direct at 6.

[192] *See* T-7 Hulbert Direct at 6.

[193] T-11 Fairchild Direct at 42-43.

[194] T-13 Sutak Direct at 12-13.

[195] Greens Creek PSA at 34-35.

[196] TA334-1, filed July 5, 2005, at 4.

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Pursuant to AEL&P's proposal to adjust its COPA balancing account on a monthly basis, firm ratepayers will make up the difference in months when sales to Greens Creek do not equal the estimated $554,480. Firm ratepayers will enjoy a reduction in rates for months when sales to Greens Creek exceed $554,480.

If we were to reject AEL&P's proposed use of the COPA mechanism, we would also have to remove the normalized Greens Creek revenue from AEL&P's proposed base rates.[197] Removing this normalized revenue would effectively increase the base rates that would be charged to AEL&P's firm customers by increasing AEL&P's revenue deficiency.[198] This increase in base rates would be partially offset if we continued to include a Greens Creek revenue credit in AEL&P's COPA mechanism.

We find that, on an annual basis, AEL&P's proposal results in 100 percent of the Greens Creek revenue being allocated to the benefit of firm customers, and that there is no net shifting of risks. Therefore, we approve inclusion of the Greens Creek revenue element proposed by AEL&P in AEL&P's COPA mechanism.

Return on Equity

AEL&P requested a return on rate base of 10.39 percent.[199] The requested return was based on a capital structure containing 46.2 percent debt and 53.8 percent equity (AEL&P's actual capital structure) and on AEL&P's actual average cost of debt of 5.3 percent. AEL&P proposed a return on equity (ROE) of 14.75 percent based on the testimony of its ROE expert, Zepp.[200] J3P did not address cost of capital issues in its testimony.[201] The AG accepted AEL&P's capital structure and 5.3 percent

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[197] Order U-91-32(1), Appendix at 14.

[198] H-20, Revenue Requirement Study, Schedules 5, 6.

[199] RRS at 8, Schedule 5, Line 5.

[200] RRS at 53, Schedule 12.

[201] T-13 (Sutak).

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debt cost as appropriate for setting rates in this proceeding.[202] However, the AG disagreed with AEL&P's requested 14.75 percent ROE and proposed an 11 percent ROE based on the testimony of its expert, Parcell. [203]

Expert Testimony

To determine cost of equity, Zepp used a proxy group of 31 electric utilities. His proxy group is comprised of all utilities listed by AUS Utility Reports in the categories "Electric Companies" and "Combination Electric and Gas Companies" that pay dividends, have investment grade bonds, have at least 51 percent of revenues derived from regulated electric revenues, are not transmission and distribution companies, and have complete and reliable data.[204] The average market capitalization of Zepp's proxy group is $8.5 billion, with the smallest having a capitalization of $700 million and the largest $25 billion.[205]

Parcell chose a proxy group consisting of five publicly-traded electric utilities that have market capitalizations of less than $1 billion and that are engaged in operations similar to AEL&P. Three of the utilities in Parcell's proxy group are part of Zepp's proxy group; two are not.[206] While Parcell's group is comprised of smaller utilities than the average of the Zepp group, the smallest utility in Parcell's sample is still 10 times larger than AEL&P, based on revenues.[207] Parcell performed his ROE analyses on Zepp's proxy group as well as on his own.[208]

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[202]T-12 (Parcell) at 6-7.

[203]T-12 (Parcell) at 36-54.

[204]T-9 (Zepp Direct) at 10-11, TMZ-2 at 1.

[205]T-9 (Zepp Direct), TMZ-2 at 1.

[206]T-12 (Parcell), DCP-2, Schedule 6 at 1.

[207]Tr. 900 (Parcell).

[208]T-12 (Parcell) at 8.

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Zepp's recommended ROE of 14.75 percent was based on his estimate of the cost of equity for electric utilities in his proxy group plus a premium to recognize increased risks faced by AEL&P.[209] Zepp found that the cost of equity for his group of publicly-traded electric utilities ranged from 10.8 percent to 11.9 percent based on three discounted cash flow (DCF) analyses and four risk premium analyses, including a capital asset pricing model (CAPM). The results of Zepp's studies were:

Constant Growth DCF Method	11.4%
FERC DCF Method	11.4%
Three-Stage DCF Method	11.1%
First Risk Premium Method Five-Year Average Ten-Year Average	 11.5% 11.1%
Second Risk Premium Method Original Updated	 11.8% 10.8%
Third Risk Premium Method	11.0%
CAPM	11.0%

Zepp testified that the average result of his DCF analyses, 11.3 percent, provides a reasonable top to his recommended range of equity cost for publicly-traded electric utilities while the average result of his risk premium estimates, 11.2 percent, was a reasonable bottom to the range.[210]

Zepp determined that AEL&P's cost of equity was at least 350 basis points above the cost of common equity of a typical publicly-traded electric utility. He recommended that an average base cost of equity of 11.25 percent (the average of his average DCF estimates and his average risk premium and CAPM estimates) be increased by 3.5 percent to 14.75 percent to recognize AEL&P's greater risks.[211]

[209]T-9 (Zepp Direct) at 4.

[210]T-9 (Zepp Direct) at 8-9, 27, 30-31; TMZ-2 at 7, 9-10, 12-14.

[211]T-9 (Zepp Direct) at 21-22.

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Zepp testified that AEL&P was riskier than the proxy group companies, in part because of its small size. He observed that AEL&P is smaller than any of the utilities in his proxy group and is less than 1 percent as large as the average of the group.[212] He further asserted that AEL&P was more risky than proxy utilities because of its take-or-pay contract for Snettisham power, its lack of interconnection with other electric utilities, its requirement for significant amounts of new capital, its liquidity risk, its limited financing flexibility, its exposure to losses due to avalanches and mud slides, and a perception by investors that Alaska utilities have greater business risks.[213]

The AG, through Parcell, disputed Zepp's analysis. Parcell believed Zepp's explicit risk adjustment of 350 basis points was unwarranted. Further, he testified that each of Zepp's DCF and risk premium methodologies and inputs suffered from defects that had the effect over over-estimating the base cost of equity.[214] In particular, he criticized Zepp for using analysts' forecasts of earnings per share exclusively in his DCF analysis. Parcell believed it improper to use a single measure of growth, especially when it reflected only projected data.[215] Parcell relied on the highest growth rate for his DCF-based ROE recommendation. He explained that, if the highest growth rate had been historical earning per share he would have relied on that. In this case he relied on analysts' forecasts because they were highest but that he would not always propose relying on them.[216]

Parcell criticized Zepp's FERC DCF method as combining two separate DCF types used by the FERC. He recalculated Zepp's FERC DCF using what he

[212]T-9 (Zepp Direct) at 13.
[213]T-9 (Zepp Direct) at 13-22.
[214]T-12 (Parcell) at 37.
[215]T-12 (Parcell) at 38.
[216]Tr. 901-902 (Parcell).

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believes is the DCF model FERC applies to electric utilities. His recalculation results in an estimated cost of equity of 10.1 percent.[217] Parcell also criticized various aspects of Zepp's risk premium analyses.[218] He concluded by asserting that Zepp's ROE estimates significantly exceed recent returns authorized by state regulatory agencies which he claims averaged 10.48 percent in 2009 and 10.34 percent in 2010.[219]

Parcell submitted his own cost of equity analyses—a constant growth DCF (one of the three DCF models used by Zepp), a CAPM analysis, and a comparable earnings analysis (CEM). Each method was applied both to his own five-company proxy group of small publicly traded utilities and to Zepp's 31-company proxy group.[220] Parcell summarized his results[221] in terms of ranges which are:

Proxy Group	DCF	CAPM	CEM
Parcell Group	10.6% to 11.2%	7.7%	Mean 8.5% to 9.9% Median 8.0% to 9.8%
Zepp Group	10.2% to 10.4%	7.7% to 7.8%	Mean 10.4% to 10.9% Median 9.5% to 10.5%

The DCF percentages contained in the chart are based on Parcell's "high" DCF results. He recommended use of his high DCF results in order to recognize the small size of AEL&P.[222] In his constant growth DCF model Parcell used five indicators of growth, including both projected and historical data.[223]

[217]T-12 (Parcell) at 46.

[218]T-12 (Parcell) at 46-50.

[219]T-12 (Parcell) at 50-51.

[220]T-12 (Parcell) at 8.

[221]T-12 (Parcell) at 25, 29, 31-32.

[222]T-12 (Parcell) at 25.

[223]T-12 (Parcell) at 23-24.

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Parcell found an appropriate ROE to be between 10.3 and 11.0 percent based on his constant growth DCF model, between 7.7 and 7.8 based on his CAPM and between 10 and 11 percent based on his CEM. He recommended the high end of those ranges, 11 percent, as the appropriate ROE for AEL&P.[224]

Parcell disagreed with Zepp about the riskiness of AEL&P compared to the electric utilities in Zepp's proxy group. He did not believe AEL&P was riskier because of its take-or-pay Snettisham contract or because of its liquidity risk and limited financing flexibility, as Zepp claimed.[225] Parcell did, however, consider AEL&P somewhat riskier than the proxy companies. He did not choose to recognize that risk by adding an explicit basis-point adjustment to the cost of equity. His ROE recommendation contained an implicit risk adjustment, he testified, because he used the highest growth rates in his DCF analysis and because he recommended the high end (11 percent) of his equity range.[226] Pacell also noted that AEL&P's equity ratio, 53.8 percent, was higher than the equity ratios of the Electric Companies and the Electric and Gas Companies listed by AUS Utility Reports, which ranged from 44 to 48 percent equity in the 2005 to 2009 period.[227]

On reply, Zepp disagreed with many aspects of Parcell's analysis and concluded that Parcell significantly understated the cost of equity of the proxy groups and AEL&P's cost of equity.[228] Zepp contended that Parcell's models should have taken into account our decision in Order U-08-157(10)/U-08-158(10). In particular, Zepp criticized Parcell's constant growth DCF analysis because Parcell included

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[224]T-12 (Parcell) at 35.

[225]T-12 (Parcell) at 51-54.

[226]T-12 (Parcell) at 6, 54.

[227]T-12 (Parcell) at 9-10, 36-54.

[228]T-10 (Zepp Reply) at 4.

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historical growth rates in his five indicators of growth rather than relying exclusively on analysts' forecasts.[229] Zepp restated Parcell's results based on his view of the guidance contained in Order U-08-157(10)/U-08-158(10).[230]

Zepp's restatement of Parcell's DCF model estimates a cost of equity of between 11.5 and 11.7 percent for the Parcell proxy group and between 11.2 and 11.4 percent for the Zepp proxy group. When Zepp restated Parcell's CAPM estimate, taking the findings of Order U-08-157(10)/U-08-158(10) into account, the CAPM cost of equity became 9.9 percent for the Parcell proxy group and 10 percent for the Zepp proxy group. Zepp did not attempt to restate Parcell's CEM analysis[231]

Parcell testified that CAPM results have been lower than DCF results in recent years because of current low yields on treasury bonds and the 2008-2009 decline in stock prices. He believes that while the CAPM estimates are lower, DCF results may be somewhat higher due to higher yields attributable to the decline in stock prices. Parcell believes it would be a mistake to entirely ignore CAPM analyses.[232] Zepp testified that, although both he and Parcell reported CAPM results, they gave them minimal weight. When Zepp restated Parcell's DCF and CAPM he weighted the constant growth DCF results 85 percent and the CAPM results 15 percent.[233]

Commission Decision

Although we consider all ROE analyses submitted to us by expert witnesses, in recent cases we have relied most heavily on the constant growth variant of the DCF model and have indicated our preferred ways of calculating it. We continue

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[229]T-10 (Zepp Reply) at 13-24.
[230]T-10 (Zepp Reply) at 4-5.
[231]T-10 (Zepp Reply) at 4-5.
[232]T-12 (Parcell) at 36.
[233]T-10 (Zepp Reply) at 5.

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to give the most weight to constant growth DCF analyses in this case. We believe that weighting is appropriate under current economic conditions.

The biggest difference between the two expert witnesses in this case is not the cost of equity they calculate for the proxy companies but the magnitude of the adjustment, whether implicit or explicit, necessary to account for the difference in risk between the proxy groups and AEL&P. Parcell believes AEL&P is somewhat riskier than the utilities in the proxy groups while Zepp believes that AEL&P's risks are greatly (350 basis points) in excess of proxy utilities.

Based on our review of the experts' testimony and all the other evidence in the record concerning the finances and operations of AEL&P, we conclude that AEL&P is riskier than the proxy utilities. However, we decline to accept that recognizing that risk requires an adjustment of 350 basis points. Conversely, we do not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk.

Considering all the testimony on the cost of equity for the proxy groups, plus the special risk and risk mitigation factors applicable to AEL&P, we find that an ROE of 12.875 percent most reasonably represents AEL&P's cost of equity. Applying a 12.875 percent ROE to the 53.8 percent equity and combining that result with the application of the undisputed cost of debt of 5.3 percent to the 46.2 percent debt results in an overall weighted cost of capital for AEL&P of 9.375 percent.[234]

<u>Rate Design</u>

After investigation we are required to ensure that rates charged by a utility are just, reasonable and neither unduly discriminatory nor preferential.[235] To aid those

[234](12.875% ROE X .538 equity) + (5.3% cost of debt X .462 debt) = 9.375% weighted cost of capital.

[235]AS 42.05.431(a).

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determinations we have adopted regulations[236] requiring preparation and submission of a cost-of-service study (COSS) under certain circumstances. Smaller utilities are generally required to submit a COSS only when actively proposing new rate designs. However, in order to more rigorously scrutinize larger electric utilities we require them to submit a COSS in every rate case. AEL&P complied with that requirement (by submitting its COSS and consultant Gray's testimony), though it intended to leave its existing rate design unchanged by implementing its proposed rate increases on an across-the-board basis.[237]

AEL&P's COSS incorporates its proposed rate increases and then compares the revenues expected to be paid by each rate class to the revenues required from each to cover its allocated costs.[238] Two rate classes would pay less than their allocated costs: Residential Rate 10 revenues were estimated to be 2.8 percent less, and Manufacturing Rate 41 revenues were estimated to be 66.5 percent less. Three rate classes would pay more than their allocated costs: Small Commercial Rate 20 revenues were estimated to be 5.7 percent more, Large Commercial Rate 24 revenues were estimated to be 1.7 percent more and Street Light Rate 46 revenues were estimated to be 1.8 percent more.[239] Gray testified that, except for Manufacturing Rate 41 revenues, these results show the proposed across-the-board rate increases yield revenues reasonably equal to the cost of providing service.[240]

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[236]3 AAC 48.500 – 3 AAC 48.560. The regulation establishes costs as the "fundamental basis" for establishing rates and recognizes the precept that a "cost causer" be "the cost payer" as one primary objective. 3 AAC 48.510(a)(1); 3AAC 48.520.

[237]TA381-1 at 7; T-1 Gray Direct at 9.

[238] The AG agreed that the COSS complied with our regulations. T-11 Fairchild Direct at 37, 40.

[239]COSS at 16; T-1 (Gray Direct) at 11; AEL&P Second Errata, TA381-1 COSS, Page 16, Revised 8-10-2010.

[240]T-1 Gray Direct at 12-13.

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Gray testifies that AEL&P currently provides service to only one customer under Manufacturing Rate 41.[241] He further states that AEL&P proposes to resolve this conflict by immediately closing Manufacturing Rate 41 to new customers and (in order to give the customer reasonable notice) terminating this rate class effective January 1, 2012.[242] On that date the customer would begin receiving service under the Large Commercial Rate 24 classification.[243] The change would be implemented through a separate tariff filing.[244]

Fairchild in her testimony on behalf of the AG[245] agrees with AEL&P's proposal to terminate the Manufacturing Rate 41 classification and serve the one customer now receiving service under that rate through the Large Commercial Rate 24 classification.[246] However, the AG makes two additional recommendations. Fairchild recommends we establish a specific 5 percent variance trigger for further evaluating the need for a rate redesign. Fairchild also recommends that we require AEL&P to re-run its COSS to reflect the modified revenue requirement approved in this proceeding and the elimination of the Manufacturing Rate 41 classification.[247] Then, If the re-run COSS indicates a greater than 5 percent deviation between the cost of serving any customer class and the revenues generated by that class, she recommends AEL&P be required to either redesign rates or explain in detail why such difference is just and reasonable.[248]

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[241]T-1 Gray Direct at 8-9.
[242]T-1 Gray Direct at 13.
[243]T-1 Gray Direct at 12.
[244]T-1 Gray Direct at 12.
[245]J3P had no position on these issues.
[246]T-11 Fairchild Direct at 40.
[247]T-11 Fairchild Direct at 40.
[248]T-11 Fairchild Direct) at 41.

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In reply Gray agrees generally that AEL&P should always be prepared to explain that its proposed rates are fair and reasonable.[249] However, he disagrees with the proposition that some specific percentage variance should be adopted here to trigger further scrutiny of AEL&P's rate design or any other utility's future rate design. He also disagrees with Fairchild's recommendation of a 5 percent variance trigger stating that a 10 percent variance would be more reasonable.[250]

The variance between the cost of providing service under Manufacturing Rate 41 and its expected revenues appears too great to comply with the requirements of our statute and regulations. However, we do not consider the matter further as AEL&P has proposed to close the class, plans to terminate it in the near future, and the AG agrees with the proposal to provide service through another class with a small variance.

That resolution leaves only one class (Small Commercial Rate 20) with a variance (5.7 percent) exceeding the 5 percent trigger supported by the AG. Neither Gray nor Fairchild referred to any published variance standards for use in determining the propriety of rates. In response to Commissioner questioning at hearing Gray stated he did not know of any such standards.[251] Gray also stated that making changes in rate design is more appropriately done in the context of smaller rate increases rather than the larger rate increases in question here.[252]

In addition both Fairchild and Gray testified that the processes involved in preparing a COSS necessarily involve a degree of imprecision. Fairchild testified that each rate class should produce revenues "reasonably close" to its allocated cost of

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[249]T-2 Gray Reply at 2.
[250]Tr. 309-316.
[251]Tr. 314.
[252]*Id.* at 317-318.

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service but requiring an exact match would “inappropriately imply a level of precision that does not exist in the COSS.”[253] On cross examination Gray similarly defended his positions by using the example of the “load research” portion of a COSS. He stated a 10 percent variance is accepted in determining that “key factor” in the COSS process.[254]

We begin our analysis by noting that the COSS-related disputes here were quite limited and consequently only a small part of our proceedings. We are therefore not convinced that this docket requires us to adopt a new analytical standard broadly applicable to any future COSS or that the understandably limited record available in this case adequately prepares us to establish a variance standard. This is particularly so in the absence of references to any commonly-accepted standard. While that absence might suggest our record here is incomplete, it might also indicate that other regulators have noted problems with that approach and have declined to adopt a variance standard. We conclude that we should move slowly in considering the adoption of any such standard. We do not adopt the standard proposed by the AG at this time.

Instead, we first conclude that we should approve the termination of Manufacturing Rate 41. At that point only one remaining class (Small Commercial Rate 20) has a variance (seven tenths of a percent) and that variance only slightly exceeds the stringent standard proposed by the AG. We find all the remaining variances demonstrated in the COSS, including Small Commercial Rate 20, demonstrate the reasonably close relationship between allocated costs and expected revenues described by Fairchild. We therefore conclude that AEL&P’s proposed rates,

[253]T-11 Fairchild Direct at 39-40.

[254]Tr. 310 – 312.

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implemented by across-the-board rate increases based upon the existing rate design, are just, reasonable, and neither unduly discriminatory nor preferential.

Rates

Based upon our determinations above, we find that AEL&P has a revenue deficiency of $6,727,383.[255] This deficiency could be recovered through a 27.24 percent across-the-board increase to energy and demand charges.[256] However, AEL&P has proposed to forego that portion of its revenue deficiency in excess of the amount that could be recovered through a 24 percent across-the-board increase to energy and demand charges.[257] We approve this proposal and grant AEL&P its requested permanent 24 percent across the board increase to energy and demand charges. We had previously granted AEL&P a 20 percent interim and refundable across the board increase to energy and demand charges in this proceeding.[258] No refund is required, and AEL&P is relieved of the obligation under Order U-10-29(2) to retain funds in an escrow account.

Other Matters

AEL&P filed a copy of its currently applicable credit card processing contract for our approval.[259] We received no comments or testimony objecting to this credit card processing contract. We accept AEL&P's credit card processing contract with Speedpay, Inc., signed March 24, 2004, as amended November 2, 2009, as fulfilling AEL&P's obligations under paragraph 13 of the stipulation approved in Order U-05-90(7).[260]

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[255]*See* Appendix B, attached.

[256]Appendix B.

[257]TA381-1 at 3-4.

[258]Order U-10-29(2) at 11.

[259]TA381-1 at 7, Exhibit 4.

[260]Order U-05-90(7), Appendix at 6.

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AEL&P was originally authorized in 1974 to implement a COPA with quarterly rate revisions.[261] Although the record is not entirely clear, it appears that AEL&P was authorized to make COPA rate revisions on a biannual basis as part of the COPA revisions authorized in 1987.[262] In this proceeding, AEL&P requested permission to file quarterly COPA revisions.[263] No party objected to this change, and we approve it.

Tariff Sheets

We approve revised Tariff Sheet Nos. 104, 105, 113, 114, 119, 128, 131, 132, 135, 136, 168, 169, 170, and 171, filed May 3, 2010, with TA381-1 under the cover sheet entitled Permanent Rates, effective the date of this order. Validated copies of the approved tariff sheets will be returned under separate cover.

Final Order

This order constitutes the final decision in this proceeding. This decision may be appealed within thirty days of the date of this order in accordance with AS 22.10.020(d) and the Alaska Rules of Court, Rules of Appellate Procedure (Alaska R. App. P. 602(a)(2)). In addition to the appellate rights afforded by AS 22.10.020(d), a party may file a petition for reconsideration as permitted by 3 AAC 48.105. If such a petition is filed, the time period for filing an appeal is then calculated under Alaska R. App. P. 602(a)(2).

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[261] Order U-74-58(1), *Order Allowing Tariff Revision to go Into Effect Temporarily Pending Investigation and Possible Hearing*, dated June 21, 1974.

[262] *See* Order U-87-57(1), *Order Suspending Permanent Operation of Tariff Filing, Approving Tariff Filing on an Interim Basis, and Requiring Reports*, dated August 5, 1987 (since that date, AEL&P has filed COPA revisions in May and October of each year).

[263] TA381-1 at 9-11.

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ORDER

THE COMMISSION FURTHER ORDERS:

1. The *Unopposed Partial Stipulation*, filed April 28, 2011, by Alaska Electric Light and Power Company and the Attorney General is accepted, subject to the express condition that no issue should be considered to have been finally determined or adjudicated by virtue of the stipulation.

2. The request filed by Alaska Electric Light and Power Company in TA381-1 for a 24 percent across-the-board permanent rate increase on energy and demand charges, is approved.

3. The interim and refundable rates established in this docket are made permanent.

4. Tariff Sheet Nos. 104, 105, 113, 114, 119, 128, 131, 132, 135, 136, 168, 169, 170, and 171, filed May 3, 2010, with TA381-1 under the cover sheet titled Permanent Rates, are approved effective the date of this order.

DATED AND EFFECTIVE at Anchorage, Alaska, this 2nd day of September, 2011.

BY DIRECTION OF THE COMMISSION
(Commissioners Kate Giard and Robert M. Pickett,
not participating.)

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