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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Power Agreement Between)
ALASKA ELECTRIC LIGHT AND POWER)
COMPANY, ALASKA INDUSTRIAL)
DEVELOPMENT AND EXPORT AUTHORITY,)
and ALASKA DEPARTMENT OF FISH & GAME)
for the Sale and Purchase of the Electric)
Capability of the Snettisham Hydro Electric)
Project)

U-97-245
Order No. 4

**ORDER ACCEPTING AND APPROVING REVENUE
REQUIREMENT, COST-OF-SERVICE, AND RATE
DESIGN STUDIES; GRANTING PARTIAL RATE
INCREASE; GRANTING PERMANENT TARIFF RATES;
AND REQUIRING FILING**

BY THE COMMISSION:

Date Filed: June 29, 2000

End of 45 Day Period: August 14, 2000

Extension Granted by Utility Until: August 24, 2000

Tariff Recommendation:

1. The Commission finds the revenue requirement, Cost of Service, and Rate Design Studies filed as TA292-1 by Alaska Electric Light and Power Company timely complies with the requirements of U-97-245(1) and U-97-245(3).

2. The Commission approves Alaska Electric Light and Power Company's revenue requirement filed as TA292-1, as adjusted for Staff recommendations.

3. The Commission grants Alaska Electric Light and Power Company permanent rates equal to the rates suspended as interim and refundable by U-97-245(1) and U-99-136(3).

4. The Commission grants Alaska Electric Light and Power Company permanent rates calculated under its TA292-1 revenue requirement, as adjusted for

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Staff recommendations and AEL&P's decision to forego its proposed Schedule 10D Residential rate increase.

5. The Commission directs Alaska Electric Light and Power Company to file by September 24, 2000, updated Tariff Sheets No. 104, 105, 113, 114, 119, 128, 132, 135, and 136, and Amendment #2 to its special contract with Juneau Ready Mix, to reflect Alaska Electric Light and Power Company's rates resulting from its approved revenue requirement and its decision to forego proposed Schedule 10D Residential proposed rate increase.

6. The Commission will investigate AEL&P's demand rates in a new docket.

Reasons for the above indicated recommendation: **Memo Attached**

Order

THE COMMISSION FURTHER ORDERS:

For good cause shown in the attached staff memorandum, the Commission accepts the recommendations set out above and directs the utility to comply.

Commission decision re this order:

	DATE ISSUED August 24, 2000		I CONCUR		I DO NOT CONCUR		I WILL WRITE A DISSENTING STATEMENT *
Thompson			/s/				
Smith			/s/				
DeMarco					/s/		Separate statement
Abbott			/s/				
Strandberg			/s/				

(S E A L)

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To Commissioners:
G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

Date: August 24, 2000
File: TA292-1
Re: Revenue Requirement
and Cost-of-Service
Studies Compliance
Filing and Proposed
Tariff Rate Revision.

From: Keith Day, Utility Financial Analyst

Recommendation

Staff recommends that:

1. The Commission should find the revenue requirement, Cost of Service, and Rate Design Studies filed as TA292-1 by Alaska Electric Light and Power Company timely complies with the requirements of U-97-245(1) and U-97-245(3).
2. The Commission should approve Alaska Electric Light and Power Company's revenue requirement filed as TA292-1, as adjusted for Staff recommendations.
3. The Commission should grant Alaska Electric Light and Power Company permanent rates equal to the rates suspended as interim and refundable by U-97-245(1) and U-99-136(3).
4. The Commission should grant Alaska Electric Light and Power Company permanent rates calculated under its TA292-1 revenue requirement, as adjusted for Staff recommendations and AEL&P's decision to forego its proposed Schedule 10D Residential proposed rate increase.
5. The Commission directs Alaska Electric Light and Power Company to file by September 24, 2000, updated Tariff Sheets No. 104, 105, 113, 114, 119, 128, 132, 135, and 136, and Amendment #2 to its special contract with Juneau Ready Mix, to reflect Alaska Electric Light and Power Company's rates resulting from its approved revenue requirement and its decision to forego proposed Schedule 10D Residential proposed rate increase.

1 6. The Commission should require Alaska Electric Light and Power Company to
2 conduct a cost-to-benefit analysis of performing an updated load study. AEL&P
3 should also include in its report detailed discussions of its current demand
4 management practices, capacity requirements, and its updated 20-year loads and
5 resources plan. Alaska Electric Light and Power Company is required to file this
6 report, on or before March 1, 2001.

7 8 Filing

9 On June 29, 2000, Alaska Electric Light and Power Company (AEL&P)
10 filed TA292-1. In its filing, AEL&P explained that the filing included its revenue
11 requirement and cost-of-service studies in compliance with Commission Order U-97-
12 245(1).¹ In addition to its required studies, AEL&P also filed a summary of the
13 Snettisham Cable Costs and a copy of the submarine cable installation contract and
14 change orders² in compliance with Commission direction in the body of Order U-97-
15 245(1).

16 AEL&P's revenue requirement utilizes a 1999 test year and indicates a
17 \$999,742 revenue deficiency based on a \$25,506,033 proforma revenue requirement
18 (before exclusion of other operating income),³ \$44,013,263 rate base,⁴ 13.00 percent
19 (%) return on equity, and 11.68% weighted cost of capital.

21
22 ¹ Order U-97-245(1), dated June 24, 1998, required AEL&P to file its revenue
23 requirement and cost-of-service studies by June 1, 2000. On March 7, 2000, AEL&P
24 requested an extension of time for filing its studies until June 30, 2000. The
Commission granted AEL&P's request for extension of time by Order U-97-245(3)
dated March 24, 2000.

25 ² See TA292-1 Exhibits 7 through 9, filed June 29, 2000.

26 ³ See TA292-1 Schedule SDC-19.

⁴ See TA292-1 Schedule SDC-9.

1 and approved implementation of those rates on a permanent basis effective November
2 1, 1996.

3
4 AEL&P's current Tariff Rates are interim and refundable pursuant to
5 Commission Orders U-97-245(1), dated June 24, 1998, and U-99-136(3), dated
6 February 10, 2000. AEL&P's rates were made interim and refundable by U-97-245(1)
7 as a condition of Commission approval of a Power Sales Agreement (PSA) between
8 AEL&P and the Alaska Industrial Development and Export Authority (AIDEA), which
9 arose from the State of Alaska's purchase of the Snettisham Hydroelectric Project
10 from the Federal Government. On January 7, 2000, AEL&P filed a tariff rate reduction
11 designed to pass through calculated savings from a partial defeasance of Snettisham
12 bonds. The Commission approved AEL&P's proposed rate reduction on an interim and
13 refundable basis by U-99-136(3), pending Commission review and approval of
14 AEL&P's 1999 revenue requirement and cost-of-service study results.

15 The PSA provides for a "take or pay" arrangement under which AEL&P is
16 obligated to make payments to AIDEA in an aggregate amount sufficient to pay all
17 project costs, including aggregate debt service on bonds and amounts required to
18 maintain bond resolution reserves. AEL&P is unconditionally and irrevocably obligated
19 to pay the project costs notwithstanding a suspension or reduction in the capability of
20 the project or any interruption, interference or curtailment of power supplied by the
21 project.⁵

22
23 AIDEA initially issued \$100 million par value bonds. After bond premium
24 of \$156,130, bond proceeds of \$99.844 million were initially applied as follows:

25
26 ⁵ See Bond issue documents dated July 15, 1998, filed August 21, 1998, in U-
97-245.

	(Dollars in Thousands)
1 Application of Bond Proceeds:	
2 Snettisham Purchase Price	\$ 81,966
3 Renewal and Replacement Fund	1,800
4 Submarine Cables (Net of \$2.5 million 5 Federal contribution)	8,400
6 Capitalized Project Costs	595
7 Debt Service Reserve Fund	4,007
8 Bond Insurance	1,484
9 Financing Costs	<u>1,591</u>
10 Total	\$99,844

11 (Source = Bond Documents filed August
12 21, 1998, in Docket U-97-245)

13
14 In the course of the transaction between AIDEA and the Federal
15 Government, it was determined that the submarine transmission cables used to
16 transport Snettisham Power to Juneau were in poor condition and were ultimately
17 replaced in 1999 at a cost of approximately \$10 million. At the time of its approval of
18 the PSA, by Order U-97-245(1), the Commission expressed concerns about the
19 uncertainty of the final cable project costs. Approval of the PSA was conditioned upon
20 not allowing recovery of total project costs in excess of \$101 million through AEL&P's
21 rates, and an initial maximum inception rate not to exceed 4.02 cents per kilowatt hour
22 (¢/kWh) was set.

23 On January 7, 2000, AEL&P filed a proposed tariff rate revision
24 requesting an across-the-board rate reduction of 1.78% (.15 ¢/kWh) to pass through
25 reductions in debt service cost due to a bond defeasance. The bond defeasance
26 primarily resulted from \$5 million dollars contributed by the Federal Government to the

1 cable replacement project and approximately \$600,000 of savings from the cable
2 replacement project coming in under budget.

3 4 Analysis

5 **Compliance** - Commission Regulations at 3 AAC 48.275(j) require Staff
6 to perform an initial analysis of the reasonableness and propriety of a utility's filing,
7 including its accuracy, representativeness, methodology, and conformance with law,
8 within 45 days of the utility's filing of a tariff rate revision. On August 9, 2000, Staff
9 requested AEL&P extend the 45-day deadline until August 24, 2000, in order to
10 provide additional time for Staff to fully address TA292-1 comments and issues.
11 AEL&P agreed and on August 9, 2000, filed a faxed confirmation of its verbal
12 authorization to extend the deadline.

13
14 Staff reviewed AEL&P's TA292-1 for compliance with the requirements
15 of 3 AAC 48.275(a) revenue-requirement supporting schedules, and compliance in
16 form with the requirements and guidelines of 3 AAC 48.500 – 560 for cost-of-service
17 and rate design studies. (See Schedule KFD-1, attached to this memo for listing of the
18 TA292-1 schedule number and the corresponding required 275(a) schedule, and
19 description of minor deficiencies noted. See also below Staff Analysis of Cost of
20 Service Study). Based on its review, Staff concludes AEL&P has complied with the
21 filing requirement form of 3 AAC 48.275(a) and 3 AAC 48.500 – 560, and recommends
22 the Commission accept AEL&P's filing as compliant with Order U-97-245(1).

23
24 **Revenue Requirement** – Staff tied the balances reported at Schedules
25 SDC-1 and SDC-2 to AEL&P's audited FERC Form 1 reports on file with the
26 Commission. In its review of 1998 and 1999 account balances, Staff has placed

1 reliance on AEL&P's auditor's work and opinion regarding appropriate income
2 statement and balance sheet classification, as well as for compliance with Generally
3 Accepted Accounting Principles (GAAP).

4
5 Staff reviewed AEL&P's comparative schedules of Income and Operating
6 Expense (Schedule SDC-2) and Assets, Liabilities, and Capital (Schedule SDC-1) for
7 significant fluctuation in 1999 balances relative to 1998. Staff noted significant
8 variances in Cost of Power Adjustment revenue (539% increase) and Internal
9 Combustion Operation expense (170% increase). Staff also noted a 51% increase in
10 Construction Work in Progress. Staff requested explanation of these variances from
11 AEL&P. AEL&P explained the increase in Cost of Power Adjustment Revenues, as
12 well as Internal Combustion Operation fluctuates annually due to increased diesel
13 generation resulting from hydraulic outages, low water, etc. Staff believes the
14 explanation is reasonable and notes the correlation in expense fluctuation is
15 reasonable. AEL&P explained the increase in Construction Work in Progress balance
16 fluctuates in relation to current projects. Staff agreed balance to audited FERC Form 1,
17 and considers explanation reasonable.

18 In the course of its review, Staff noted AEL&P had not included executive
19 compensation at page 104 of the FERC Form 1. Staff contacted AEL&P and
20 requested an amended page 104 providing the required information. AEL&P readily
21 complied and filed an amended page 104. Staff reviewed the executive compensation
22 reported, and concludes amounts are reasonable for a utility of AEL&P's size.

23
24 Staff queried AEL&P regarding lobbying expense and AEL&P explained
25 that it incurred \$20,000 in lobbying expense during the test period. AEL&P asserted
26 that the test period lobbying expense was entirely related to obtaining additional

1 federal funds to defray the submarine cable costs replacements, however AEL&P
2 routinely incurs lobbying expense. The Commission has a long history of not allowing
3 utilities to recover lobbying expense through rates under AS 42.05.381(a), absent a
4 demonstrable benefit to ratepayers.⁶ However, the Commission has previously allowed
5 Golden Valley Electric Association to recover lobbying expense associated with the
6 funding of the Anchorage-Fairbanks intertie system.⁷ Based on this precedence, and
7 due to the nature of the expense, Staff recommends the Commission allow AEL&P to
8 recover one fifth of the cost of this expense in its revenue requirement based on an
9 estimated five year interval to AEL&P's next rate case. See Adjustment 2 at Schedule
10 KFD-2, which reduces AEL&P's proposed revenue requirement by \$16,000.

11
12 **Rate Base** – Staff reviewed AEL&P's proposed rate base and agreed
13 the year-end balances used in the average 13-month balance calculation to AEL&P's
14 audited FERC Form 1 without exception.

15 Staff noted that AEL&P had not included unamortized balance of diesel
16 generator overhauls recorded on the balance sheet in rate base. Staff inquired of
17 AEL&P as to why it did not include these assets in rate base for cost recovery. AEL&P
18 explained it had inadvertently omitted the overhauls and requested inclusion of the
19 thirteen-month average balance in rate base. Staff concurs with AEL&P that the assets
20 should be included in rate base and notes AEL&P's last approved revenue
21 requirement included provision for unamortized overhauls. Staff recommends the
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25 ⁶ See U-78-4(33) 3 APUC 371.

26 ⁷ See U-81-48(19) 5 APUC 152.

1 Commission accept an adjustment of \$317,421 to properly include the thirteen-month
2 average balance of these assets in rate base.⁸

3
4 Staff also noted that AEL&P had not included provision for a \$920,352
5 Regulatory Liability recorded on its December 31, 1999 balance sheet in its rate base
6 calculation. Staff inquired of AEL&P as to the nature of the liability, and was informed
7 that the liability was originally recorded at the time of AEL&P's adoption of Financial
8 Accounting Standards Board (FASB) number 109. FASB 109 required changes in
9 accounting for deferred tax liabilities for most "for profit" entities that maintain their
10 accounts in accordance with GAAP. AEL&P consulted with the public accounting firm
11 of Deloitte & Touche, LLP, which provides auditing and tax services to AEL&P, and
12 requested they provided a discussion of the nature of the liability.

13 Staff participated in a conference call on August 7, 2000, with AEL&P's
14 management and its tax accountants to discuss the matter. In the conversation, Staff
15 explained that unless shown support for exclusion from rate base, the liability should
16 be treated consistently with recorded deferred tax liability and deferred investment tax
17 credit. AEL&P and its accountants concurred with Staff that an adjustment appears
18 warranted at this time, subject to AEL&P's and its accountants further research.
19 AEL&P asserted it believes consistent treatment requires netting the Regulatory
20 Liability with the balance of Other Regulatory Asset recorded on its balance sheet, as
21 the asset balance is directly related to the liability. Staff concurs with AEL&P, and
22 proposes an adjustment reducing AEL&P's proposed rate base by \$889,011, the net
23 amount of the thirteen-month average of the liability and asset.⁹

24
25 ⁸ See Adjustment 1A at Schedule KFD-2.

26 ⁹ See Adjustment 1B at Schedule KFD-2.

1 Staff notes AEL&P included customer deposits less than \$100 dollars,
2 along with advances to construction, as a reduction to rate base. However AEL&P did
3 include the balance of customer deposits, those in excess of \$100 in its calculation of
4 weighted cost-of-capital (See Schedule SDC-12). AEL&P is required to pay interest
5 on customer deposits in excess of \$100, per Section 6.6 of its tariff (see Tariff Sheet
6 No. 33). Staff believes this treatment is reasonable, as inclusion of customer deposit
7 balances subject to interest in the weighted cost-of-capital calculation represents a low
8 cost source of capital to the utility and serves to reduce the overall weighted rate of
9 return.

10 **Working Capital** – Staff reviewed AEL&P’s calculation of proforma
11 working capital at Schedule SDC-10, noting AEL&P utilized a 12.5% (45 day) working
12 capital requirement. Staff concludes that use of the 12.5% of proforma operating
13 expenses is reasonable and is a methodology traditionally accepted by the
14 Commission.

15
16 Staff concludes that other than the proposed adjustments described
17 elsewhere, AEL&P’s proposed calculation of rate base and working capital appears
18 reasonable and has been calculated consistent with AEL&P’s current approved
19 revenue requirement.

20 **Utility Plant and Depreciation** – Staff reviewed AEL&P’s schedules of
21 utility plant accumulated depreciation and summary of depreciation expense
22 (Schedule CSH-1) for reasonableness and on a test basis, compared balances,
23 depreciation methods, and depreciation rates with those filed in its last approved rate
24 case (U-96-34). Staff agreed balances to AEL&P’s audited 1999 FERC Form 1, filed
25 with the Commission May 1, 2000. Staff notes 1999 depreciation expense at Schedule
26

1 CSH-1 does not agree with depreciation expense reported per FERC Form 1
2 (Schedule CSH-1 includes \$204,537 Transportation Clearing expense). Staff
3 discussed difference with AEL&P, who explained transportation clearing account
4 balances were directly expensed to operating and capital accounts, rather than
5 depreciation expense. Staff concludes inclusion of \$3,162,524 depreciation expense
6 per FERC Form 1 in revenue requirement is appropriate. Based on testwork
7 performed, Staff concludes plant balances, accumulated depreciation, and
8 depreciation expense appear reasonable and are recorded consistently with AEL&P's
9 current approved revenue requirement.

10
11 **Income Tax Computation** – Staff reviewed AEL&P's computation of
12 proforma state and federal income tax, noting methodology is proper, however
13 additional adjustment is required to flow the effect of Staff's proposed adjustments to
14 rate base and operating expense. See Schedule KFD-2 for adjustment of proforma
15 income tax in proforma revenue requirement.

16 **Weighted Cost of Capital** – AEL&P's current effective return on equity
17 is 14%, as approved by U-96-34(3), with an 11.53% weighted cost of capital. In
18 TA292-1, AEL&P is proposing a 13% effective return on equity and a weighted cost of
19 capital of 11.68%. Although AEL&P is requesting a 1% decrease to its effective return
20 on equity rate, the company's capital structure has changed. The overall increase in
21 combined weighted cost of capital primarily results from AEL&P's increase in equity as
22 a percentage of total capital since 1995. AEL&P's equity changed from 49.28%
23 reported for the 1995 test year to 70.21% for 1999 test year.

24
25 Other than reducing its effective return on equity by 1%, AEL&P did not
26 provide support for its proposed 13% return on equity. Staff discussed the propriety of

1 the 13% requested return on equity with AEL&P. AEL&P explained that because it
2 has recorded a long-term liability on its balance sheet to represent the “take-or-pay”
3 PSA liability, its ability to attract favorable credit for long term investment is somewhat
4 diminished, in that the bond market would likely include the liability in review of its
5 capital structure. Staff notes that AEL&P provided extensive pre-filed testimony in
6 Docket U-96-34 regarding the effect of the anticipated purchase of the Snettisham
7 project. Staff reviewed the record of that discussion of AEL&P’s cost of equity and
8 believes the underlying situation is unchanged, although AEL&P has achieved
9 somewhat greater equity as of 1999, than estimated in U-96-34.

10
11 Staff does not propose adjustment to AEL&P’s requested 13% return on
12 equity and 11.68% weighted cost of capital. Staff believes the reduction is appropriate,
13 based on achieved equity position compared with what was estimated and approved in
14 U-96-34.

15 **Revenue Proforma Adjustments** – AEL&P provided a summary of its
16 proposed proforma revenue adjustments, which reduce test period revenues by
17 \$777,768, at TA292-1 Schedule SDC-3. In addition to reducing proforma revenue by
18 \$282,889, the amount recovered through its Cost of Power Adjustment (COPA),
19 AEL&P also proposed three adjustments as shown at Schedule SDC-16.

20
21 Proforma Revenue Adjustment 1, reduced revenue from all rate
22 schedules which had been reduced by AEL&P’s calendar year 2000 .15¢/kWh across-
23 the-board rate reduction approved by Order U-99-136(3), effective January 1, 2000.
24 Staff agreed test year KWh sales per Schedule SDC-16 with sales reported per the
25 1999 FERC Form 1, page 304, without material exception. Staff concludes adjustment
26

1 is reasonable and appropriate to reflect prospective revenues adjusted for rate
2 decrease occurring subsequent to test period.

3
4 Proforma Revenue Adjustment 2 reduced revenues by \$38,283 to reflect
5 surplus energy sales refunded customers through AEL&P's COPA. See SDC-17 for
6 AEL&P's calculation of surplus revenue refunded through COPA.

7 Proforma Revenue Adjustment 3 reduces sales by one-fifth under
8 assumption that these interruptible sales revenues are not predictable.¹⁰

9
10 Staff agreed sales on which Adjustments 2 and 3 were calculated to
11 FERC Form 1 without material exception. Adjustment 3 is not cost-based, however it
12 is consistent with methodology allowed by Order U-96-34(3). Additionally, the
13 underlying sales, when compared to the 1995 test period amount, appear to reflect the
14 realization of AEL&P's expectations of declining interruptible sales. Staff concludes the
15 adjustment is reasonable.

16 **Operating Expense Proforma Adjustments** – In its filing, AEL&P
17 proposes eight proforma adjustments at Schedule SDC-5, that in aggregate reduce
18 test period operating expenses by \$550,379. Those adjustments are described as
19 follows:

20
21 Proforma Adjustment 1 reduces operating expense by test period fuel
22 costs that are recovered through the COPA. Staff agreed the \$322,549 fuel cost per

23 ¹⁰ This adjustment is consistent with the stipulation approved by U-96-34(3). In
24 that proceeding, Staff protested AEL&P's proposed elimination of all test period
25 interruptible sales from the revenue requirement as the adjustment was not based on
26 known and measurable criteria. The stipulation represented an agreement where
AEL&P was permitted to eliminate 20% of test period revenue on the assumption that

1 Schedule SDC-5 to FERC Form 1 at pages 402 and 403. Staff concludes adjustment
2 is proper and reasonable.

3 Proforma Adjustment 2 increases proforma expense \$18,442 to
4 annualize test period labor cost for engineer hired 5/14/99. Staff recalculated without
5 material exception and concludes adjustment is reasonable.
6

7 Proforma Adjustment 3 increases property tax expense \$21,719 for
8 FY2000 rate increase. Staff recalculated without material exception and concludes the
9 adjustment is reasonable.

10 Proforma Adjustment 4 increases test period operations and
11 maintenance wages and salary expense by \$104,774. Staff reviewed proposed
12 adjustments and concludes they appear reasonable.
13

14 Proforma Adjustment 5 decreases Purchased Power (debt service)
15 expense by \$426,226 due to the bond defeasance discussed above. Staff agreed the
16 reduction and proforma proposed debt service to schedule of AIDEA Power Revenue
17 Bonds – Debt Service after Defeasance, prepared by US Bancorp Piper Jaffray Inc.,
18 included in the supporting documentation filed by AEL&P in support of its proposed
19 rate reduction in docket U-99-136, on January 7, 2000. Staff concludes adjustment is
20 reasonable and properly reflects a known and measurable item. The table below
21 details the components of the estimated 2000 purchased power cost, as reported in
22 docket U-99-136 (this schedule differs from the \$8,105,034 proforma 2000 cost
23 reported in TA292-1 by \$858 dollars. (This table is included for informational purposes
24

25
26 increasing demand for firm power and periodic water shortages would curtail future
sales to some degree.

1 only, to show the components of purchased power costs. Staff considers the \$858
2 difference noted immaterial):

3	Snettisham Bond Debt Service (principle/interest)	\$5,921,029
4	Interest on Debt Service Reserve Fund	(203,449)
5	AIDEA Administration Costs	50,000
6	Payments into Repair and Replacement Fund	685,279
7	Snettisham O&M	1,343,033
8	AEL&P Administrative Overhead	100,000
9	Insurance Expense	<u>210,000</u>
10	Total Purchased Power	\$8,105,892
11	<small>(Source = AEL&P worksheet supporting proposed rate reduction, filed January 7, 12 2000, in Docket U-99-136)</small>	

13
14
15 Renewal and Replacement Fund – Staff agreed the 3% increase at
16 Schedule SDC-5 to the terms of the Purchase Power Agreement filed in Docket U-97-
17 245, and concludes amount is reasonable.

18 Proforma Adjustment 6 reflects an 8.9% increase for the non-union
19 medical insurance premiums, effective March 1, 2000. Staff concludes adjustment
20 appears reasonable.

21
22 Proforma Adjustment 7 increases test period distribution expense by
23 \$26,091 to correct for overstatement of 1998 expense due to an error that was
24 corrected in 1999. Staff concludes adjustment appears reasonable.

25
26

1 Proforma Adjustment 8 increases test period operations and
2 maintenance expense by \$9,090 to reflect increases to NECCA employee benefits.
3 Staff concludes adjustment appears reasonable.

4 Staff reviewed AEL&P's allocations of proforma operating expense
5 adjustments at Schedule SDC-6, noting the allocations appear reasonable. Staff
6 concludes proposed proforma adjustments to operating expenses are reasonable.
7

8 **Cost-of-Service Study** – AEL&P has proposed a rate structure
9 designed to recover its costs from customers based on its cost of service study.
10 AEL&P's Schedule CSH-8 shows the cost recovery proposed differs from AEL&P's
11 calculation of fully allocated cost based rates by less than 8% by customer class.
12 AEL&P asserts it has prepared its cost of service study generally consistent with the
13 studies it has filed since the mid-1980's. The study is based on load studies conducted
14 in 1984, and has been updated for costs and customer class consumption occurring
15 since the original study, but does has not been updated to reflect current demand by
16 customer class or season.

17 Staff is unable to determine with high precision that AEL&P's allocation
18 of costs to its Schedule 10D customers is reasonable. Staff believes the underlying
19 logic that AEL&P's customers with all electric service represent poorer load factors
20 than a similar customer using other than electric heating is valid. However the age of
21 the underlying data is of concern to Staff. AEL&P has approximately 280 customers
22 receiving service under its Schedule 10D.¹¹
23

24
25
26 ¹¹ See U-81-44(7) 5 APUC 1, U-83-16 Bench Order 6 APUC 3, U-84-50(5) 6
APUC 696, for history of AEL&P's implementation of residential demand rates.

1 Staff's review of the cost of service study indicates it conforms to the
2 requirements of 3 AAC 48.500 – 560, in that costs are functionalized and allocated to
3 customer classes and is generally designed to assign costs to cost causers. However,
4 Staff believes the underlying load studies are significantly dated and may not properly
5 reflect change since the load studies were performed 14 years ago.

6 Staff discussed this concern with AEL&P management, who concurred
7 that it has been a long time since the last study, however they generally believe that
8 the customer class relationships have not changed significantly since the 1984 study.
9 Staff discussed the merits of performing a new study with management, who indicated
10 that they have not performed a recent analysis of the relative cost to benefit of
11 performing a new study. AEL&P did indicate it believes changes in technology may
12 result in a lower cost than the last study performed, which they indicated cost several
13 hundred thousand dollars.

14
15 Although Staff is not recommending removal of the residential demand
16 rate (Schedule 10D) from AEL&P's rate structure at this time, Staff believes that given
17 the significant interval since the last study was performed, as well as ratepayer
18 concerns regarding the reasonableness of allocation of demand cost this class of
19 customers, a cost-benefit analysis of performing a new load study is warranted.

20
21 Staff recommends the Commission require AEL&P to conduct this
22 analysis and provide a report to the Commission detailing the estimated costs of
23 performing a new study and its analysis of the relative cost-to-benefits of such a study.
24 AEL&P should be required to provide the Commission with the results of its analysis
25 within six months from the date of this order.
26

1 **Residential Demand Charges** – Staff requested AEL&P provide data
2 showing the load characteristics of a sample of customers on the Schedule 10D rate.
3 In response, AEL&P e-mailed to Staff a spreadsheet containing the most recent 12
4 month consumption and demand by month, for all customers residing at the Fireweed
5 Place residential building. AEL&P also provided a schedule showing the difference in
6 those customers’ annual electric costs calculated under the proposed Schedule 10
7 two-part rates and the Schedule 10D three-part rates.

8
9 On a test basis, Staff agreed demand and consumption amounts to
10 invoice copies provided by residents filing comments and recalculated annual cost
11 amounts. The results of the comparison are shown at Schedule KFD-4. For those
12 customers with load controllers installed, the differences ranged from 4% to 66%
13 greater under Schedule 10D rates. For those customers without load controllers, the
14 differences ranged from 17% to 151% greater under Schedule 10D rates. Staff
15 discussed the results of the comparison with AEL&P, who attributed the range in
16 differences as positively correlated with each unit’s load factor. Because of this,
17 AEL&P contends the results are supportive of the cost-causer/cost-payer principle of
18 cost allocation underlying the Schedule 10D rates.

19 Staff is concerned about the precision of the manner in which the costs
20 are allocated to this relatively small customer class. AEL&P generally agreed that it is
21 difficult to determine the precision of the allocation without current representative load
22 data for the other classes of customers that don’t have demand meters.

23
24 In order to allow the Commission time to review the results of AEL&P’s
25 cost-to-benefit analysis of performing a new load study AEL&P agreed to forego its
26 proposed increase to the Schedule 10D rates at this time. This will also allow the

1 Commission time to review AEL&P's capacity planning and management program as
2 well as forecast load characteristics. Staff has estimated the impact on its revenue
3 requirement of AEL&P foregoing its proposed rate increases to Schedule 10D rates as
4 approximately \$15,000. Staff believes this to be reasonable and also believes it does
5 not result in an unreasonable prejudice or preference to any other class of AEL&P
6 customer.

7
8 Staff notes AEL&P's most recent capacity addition was a 23-megawatt
9 standby unit in added in 1994. According to management, it is AEL&P's policy to
10 maintain reserve standby capacity sufficient to meet existing demand in the event of
11 the loss of Snettisham power with the largest of its standby units inoperable.¹²

12 **Tariff Sheets** – Staff recommends the Commission direct Alaska Electric
13 Light and Power Company to file by September 24, 2000, updated Tariff Sheets No.
14 104, 105, 113, 114, 119, 128, 132,135, and 136. The tariff sheets should reflect Alaska
15 Electric Light and Power Company's rates resulting from its approved revenue
16 requirement and its decision to forego proposed Schedule 10D Residential proposed
17 rate increase.

18 **Comments** – Virtually all of the comments received regarding TA292-1
19 concerned objections to the residential demand component of Schedule 10D. The
20 majority of those were also opposed to a rate increase in general. The comments
21 generally objected to a perceived inequity in the Schedule 10 and Schedule 10D rates.
22

23 AEL&P's response to those comments provided some history of the
24 residential demand rate and explained why it was implemented and approved by the
25 Commission. AEL&P explained that it met with the developers of the Fireweed Place
26

1 and Crest condominium complexes and urged them to reconsider installing electric
2 heat systems. (AEL&P also included in its comments a copy of a letter to the
3 developer of the Fireweed Place complex explaining the advantages of installing load
4 controllers.) AEL&P also asserts that it lent the Fireweed Place complex four
5 demonstration load controllers, however, Fireweed Place has not installed additional
6 controllers to date.

7
8 In its comments, AEL&P asserts that residential demand rates are cost
9 based, send the appropriate price signal, and have successfully discouraged new
10 residential construction from heating with electricity thus reducing AEL&P's need to
11 invest in additional expensive peaking capacity.

12 There are approximately 280 AEL&P customers currently on the
13 Schedule 10D rate, however, there are several thousand similarly situated customers
14 who are on the Schedule 10 rate; as Schedule 10D applies primarily to post-1985
15 electrically heated construction.

16
17
18 **OTHER MATTERS**

19
20 Snettisham Purchased Power Treatment – In order U-97-245(1), the
21 Commission expressed concerns regarding the cost of purchasing the Snettisham
22 Project and set restrictions on the amount of costs recovered through rates. AEL&P's
23 filing indicates that the transaction was completed with costs within the parameters set
24 by the Commission. In compliance with U-97-245(1), AEL&P also filed a detailed
25 summary of the submarine cable replacement contract costs with TA291-2. Staff
26

¹² See Schedule KFD-5 for listing of AEL&P's generation capacity.

1 performed a cursory review of those documents noting no unusual items. As the
2 Snettisham Project transaction was completed within the Commission's cost
3 parameters and under budget, Staff recommends the Commission grant permanent
4 rates equal to those suspended as interim and refundable by U-97-245(1) and U-99-
5 136(3).

6 Conclusion

7 Staff concludes AEL&P's revenue requirement has been prepared
8 consistent with its last-approved revenue requirement. The revenue requirement ties
9 to supporting audited FERC Form 1 reports, and after Staff's proposed adjustments,
10 appears reasonable. The rate of increase in AEL&P's costs since its last-approved
11 revenue requirement test period (1995) is lower than the change in inflation rate for
12 Anchorage over the same period¹³ and the proforma adjustments to its test period
13 balances appear reasonable.

14 Staff discussed its proposed revenue requirement adjustments (as
15 shown on Schedule KFD-2) with AEL&P, who concurred with their propriety. AEL&P
16 and Staff recalculated the rates resulting from the recommended adjustments. (See
17 Schedule KFD-6 for detail of comparison of current rates to proposed and adjusted
18 rates.) Staff recommends the Commission approve AEL&P's adjusted proforma rate
19 base of \$5,073,754 and proforma revenue requirement of \$25,387,828, as shown with
20 proposed adjustments to amounts filed by AEL&P in TA 292-1 at Schedule KFD-2.

21 Staff concludes that AEL&P's treatment of the Snettisham Project
22 acquisition by AIDEA in its revenue requirement appears reasonable and consistent
23

24
25 _____
26 ¹³ See Schedule KFD-3 for comparison of change in revenue requirement to
change in Anchorage consumer price index.

1 with Order U-97-245(1). AEL&P completed the transaction, including the replacement
2 of the submarine cables, within the cost parameters required by U-97-245(1). Staff
3 recommends the Commission approve the interim and refundable rates required by U-
4 97-245(1) and U-99-136(3) as permanent.

5
6 Staff believes AEL&P's cost of service and rate design studies follow
7 Commission guidelines and regulations. Although the underlying data may likely be
8 stale enough to result in some distorted allocation of costs to customer classes, Staff
9 believes it provides the best method of cost based allocation currently available. Other
10 than the demand component of Schedule 10D, Staff believes its use is the best
11 available methodology for assigning current costs.

12 However, Staff believes the Commission should require AEL&P to
13 perform a cost-to-benefit analysis of performing an updated load study, and provide
14 the Commission with a report on that analysis within six months of this order. AEL&P
15 should include in its report detailed discussions of its current demand management
16 practices, capacity requirements, and its updated 20-year loads and resources plan.

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3 AAC 48.275(a) tariff revision required supporting schedules:	TA292-1 Schedule #
(1) a comparative statement of assets, liabilities, and other credits as of the end of each of the two calendar or fiscal years preceding the date of filing;	SDC-1
(2) a comparative statement of income and operating expenses as of the end of each of the two calendar or fiscal years preceding the date of filing;	SDC-2
(3) a comparative statement of changes in the utility's or pipeline carrier's equity position to include fluctuations in capital stock, retained earnings, owner's equity, or fund balances for each of the two calendar or fiscal years preceding the date of filing;	*
(4) a schedule showing the amount of the proposed rate change, both in absolute dollars and as a percentage increase or decrease, applied to the most recent approved permanent tariff rates and charges for each customer or service classification;	CSH-10 **
(5) a schedule showing the computations of revenue requirement, and revenue deficiency or surplus, in both absolute dollars and as a percentage of revenues, for the normalized test-year;	SDC-19
(6) a schedule showing test-year operating revenues and expenses, pro forma adjustments, and the resulting normalized test-year operating revenues and expenses;	SDC-4
(7) a schedule showing the computation of and a narrative explanation for any pro forma adjustments to the test-year results of operations;	SDC-5, SDC-6
(8) a schedule showing the computation of the pro forma provision for income taxes for the normalized test-year	SDC-15
(9) a schedule showing the computation of rate base using a 13-month average (the arithmetic sum of the beginning of each month net balance for the 12-month test period, plus the balance at the end of the twelfth month of the test period, divided by 13) of all rate-base components except cash working capital allowance, and using any other rate-base theory the utility or pipeline carrier considers appropriate and supportable;	SDC-9
(10) a summary of utility, or pipeline, plant and depreciation for each of the two calendar or fiscal years preceding the date of filing, showing plant in service; depreciation expense for each plant account; depreciation method; asset life; and net salvage used for computing that depreciation expense and the end-of-year balance of each plant account and the related account for accumulated depreciation;	CSH-1
(11) a schedule showing the pro forma cash working capital requirement based on the normalized test-year;	SDC-10

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<p>(12) a schedule showing the computation of weighted cost of capital, separately delineating the percentage amount and embedded cost of debt, and the percentage amount and rate of return on equity, together with a schedule showing the resultant returns on each of the rate bases computed in (9) of this subsection;</p>	<p>SDC-12</p>
<p>(13) a schedule showing all liabilities of longterm debt for each of the two calendar or fiscal years preceding the filing, including a description of each obligation; nominal date of issue; date of maturity; authorized face amount; and the computation of the embedded cost of debt used in (12) of this subsection.</p>	<p>SDC-11</p>
<p>* AEL&P did not include a corresponding schedule, however Staff believes the required information is contained elsewhere in TA292-1 and AEL&P's audited FERC Form 1 reports on file with the Commission and was able to complete its review without the schedule. Staff does not believe the omission material to require rejection for lack of form.</p>	
<p>** AEL&P provided a schedule of current and proposed rates at CSH-10, however the schedule does not show the absolute dollar and percentage changes proposed. Schedules showing those changes for rates calculated under its adjusted revenue requirement are shown at Schedule KFD-6.</p>	

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Tariff Advice No. 292-1 Re:U-97-245

PROFORMA REVENUE
 REQUIREMENT ADJUSTMENTS

DESCRIPTION	AMOUNT	Staff Proposed Adjustments	Adjusted Revenue Requirement
OPERATING EXPENSES (SDC-4)	18,218,244	{2} (16,000)	18,202,244
KNOWN CHANGES (SDC-4)	(550,378)		(550,378)
TOTAL OPERATING EXPENSES AND KNOWN CHANGES	17,667,866		17,651,866
ADD:			
RETURN OF: (SDC -12)	11.68%		
ON AVG. RATE BASE OF: (SDC-9)	44,013,263	5,140,749 {1} (66,995)	5,073,754
INCOME TAXES (SDC-15)	2,697,418	{3} (35,210)	2,662,208
TOTAL PROFORMA REVENUE REQUIREMENT (SDC-14)	25,506,033	(118,205)	25,387,828

Staff Proposed Rate Base Adjustments:

	Rate base as filed	44,013,263
{1a}	Add 13-Month Unamortized Overhaul	317,421
{1b}	Less 13 Month Avg. Net Regulatory Asset/Liability	(889,011)
{1c}	Less Reduction to WC for Lobbying Expense	(2,000)
	Total Proposed Adjustments	(573,590)
	Adjusted Rate Base	43,439,673
	Return @ 11.68%	5,073,754
	Proposed Return	5,140,749
{1}	Difference	(66,995)

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The table below compares the percentage change between AEL&P's last approved revenue requirement based on a 1995 test year with its adjusted proposed revenue requirement and the change in consumer price index (CPI) for Anchorage during the same period. (Anchorage is the only Alaskan community for which Bureau of Labor CPI data is maintained. Source is U.S. Department of Labor, Bureau of Labor Statistics.)

<u>Year</u>	<u>CPI</u>	<u>% Change</u>	<u>Point Change</u>	<u>Net Increase</u>
1995	138.9			
1996	142.7	2.7%	3.8	
1997	144.8	1.5%	2.1	
1998	146.9	1.5%	2.1	
1999	148.4	1.0%	1.5	
* 2000	150.0	1.1%	1.6	
			11.1	7.99%
* Midyear 2000				
Revenue Requirement approved by U-96-34(3)				24,061,864
TA292-1 Revenue Requirement (adjusted)				25,387,828
Dollar Change				1,325,964
Percentage Change				5.51%

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Rate Schedule	Customer Charge	Demand Charge per KW	Energy Cost per Kwhr	
Nov-May	10	\$8.50	\$0.0922	
Jun-Oct	10	\$8.50	\$0.0758	
Annualized	10	\$8.50		
Nov-May	10D	\$11.00	\$8.97	\$0.0466
Jun-Oct	10D	\$11.00	\$5.43	\$0.0407
Annualized	10D	\$11.00	\$7.50	

Bold Accounts indicate load controller installed 4/9/99.

Account	kW	kWh	L.F.	Annual Bills		
				10	10D	% Difference
13964520	79.41	9210	16%	\$ 905.26	\$ 1,150.04	27%
13964523	92.64	11384	17%	\$ 1,082.61	\$ 1,326.28	23%
13964526	63.25	5948	13%	\$ 603.37	\$ 817.26	35%
13964529	57.03	5576	13%	\$ 596.38	\$ 831.45	39%
13964532	15.31	2250	20%	\$ 305.73	\$ 359.50	18%
13964535	42.47	2618	8%	\$ 319.39	\$ 588.30	84%
13964538	74.1	8142	15%	\$ 799.43	\$ 1,051.01	31%
13964541	64.84	6142	13%	\$ 640.72	\$ 901.45	41%
13964544	68.86	8287	16%	\$ 829.10	\$ 1,057.84	28%
13964547	110.72	13687	17%	\$ 1,293.52	\$ 1,575.33	22%
13964550	71.19	3985	8%	\$ 461.10	\$ 876.43	90%
13964553	51.38	4035	11%	\$ 456.51	\$ 715.63	57%
13964556	51.41	9189	24%	\$ 912.11	\$ 947.40	4%
13964559	7.87	308	5%	\$ 130.40	\$ 216.03	66%
13964562	91.31	4573	7%	\$ 487.62	\$ 1,006.73	106%
13964565	89.4	9090	14%	\$ 900.31	\$ 1,221.81	36%
13964568	44.53	3141	10%	\$ 363.31	\$ 593.43	63%
13964571	27.69	1001	5%	\$ 183.17	\$ 354.10	93%
13964574	4.56	372	11%	\$ 133.76	\$ 182.81	37%
13964577	94.83	4132	6%	\$ 464.42	\$ 1,061.10	128%
13964580	111.56	4229	5%	\$ 462.51	\$ 1,140.38	147%
13964583	18	413	3%	\$ 133.85	\$ 251.66	88%
13964586	46.39	2053	6%	\$ 279.71	\$ 568.43	103%
13964589	39.53	1645	6%	\$ 242.47	\$ 500.45	106%
13964592	9.78	450	6%	\$ 139.73	\$ 214.32	53%
13964595	52.59	3688	10%	\$ 418.75	\$ 696.95	66%
13964598	93.52	12008	18%	\$ 1,140.50	\$ 1,378.81	21%
13964611	33.01	1245	5%	\$ 214.13	\$ 468.42	119%
13964614	85.11	8281	13%	\$ 810.37	\$ 1,141.10	41%
13964617	68.27	5186	10%	\$ 556.42	\$ 885.83	59%
13964620	65.01	4006	8%	\$ 443.57	\$ 793.24	79%
13964623	70.63	4114	8%	\$ 456.09	\$ 849.71	86%
13964626	85.87	4852	8%	\$ 527.20	\$ 1,003.53	90%

1	13964629	50.42	3185	9%	\$ 381.06	\$ 660.67	73%
	13964632	6.83	573	11%	\$ 148.99	\$ 205.55	38%
2	13964635	55.09	2226	6%	\$ 293.26	\$ 646.31	120%
	13964638	87.37	7726	12%	\$ 769.93	\$ 1,151.30	50%
3	13964641	32.05	932	4%	\$ 185.22	\$ 450.48	143%
	13964644	67.11	4585	9%	\$ 493.89	\$ 839.54	70%
4	13964647	78.97	4078	7%	\$ 452.54	\$ 905.73	100%
	13964650	36.39	2778	10%	\$ 340.91	\$ 535.69	57%
5	13964653	76.35	4902	9%	\$ 512.24	\$ 899.09	76%
6	13964656	23.42	2648	15%	\$ 326.79	\$ 421.73	29%
	13964659	74.88	3873	7%	\$ 433.06	\$ 868.63	101%
7	13964662	51.74	3224	9%	\$ 385.77	\$ 672.96	74%
	13964665	71.84	2064	4%	\$ 276.72	\$ 757.77	174%
8	13964668	97.43	13347	19%	\$ 1,258.88	\$ 1,468.12	17%
9	13964671	52.32	3519	9%	\$ 405.95	\$ 699.55	72%
	13964674	33.14	1415	6%	\$ 229.53	\$ 484.27	111%
10	13964677	42.86	1577	5%	\$ 236.66	\$ 522.92	121%
	13964680	65.67	8352	17%	\$ 828.45	\$ 1,005.30	21%
11	13964684	88.6	7205	11%	\$ 732.19	\$ 1,137.26	55%
	13964687	86.07	3398	5%	\$ 396.73	\$ 929.87	134%
12	13964690	4.25	487	16%	\$ 143.36	\$ 185.35	29%
	13964693	82.21	3283	5%	\$ 387.26	\$ 913.66	136%
13	13964696	115.67	5822	7%	\$ 608.79	\$ 1,302.17	114%
14	13964699	70.25	4183	8%	\$ 461.30	\$ 844.53	83%
	13964712	67.8	3632	7%	\$ 417.40	\$ 814.73	95%
15	13964715	61.62	2920	6%	\$ 357.15	\$ 754.82	111%
	13964718	73.27	3204	6%	\$ 378.70	\$ 831.98	120%
16	13964721	35.91	926	4%	\$ 180.10	\$ 452.13	151%
	13964724	71.67	4101	8%	\$ 453.61	\$ 854.08	88%
17	13964727	96.37	7914	11%	\$ 795.31	\$ 1,211.83	52%
	13964730	26.74	988	5%	\$ 182.97	\$ 347.99	90%
18	13964733	67.47	4836	10%	\$ 519.77	\$ 842.29	62%
	13964736	92.82	6360	9%	\$ 651.16	\$ 1,105.77	70%
19	13964739	66.42	2957	6%	\$ 357.30	\$ 767.09	115%
20					\$ 32,676.48	\$ 53,217.88	63%
21				Difference:		\$ 20,541.40	
22							
23							
24							
25							
26							

1				Capacity	
2	Plant	Year Installed		(Net Peak Demand mWh)	
3	Snettisham Project:				
	Long Lake	1973 +		47	
4	Crater Lake	1990 +		31	
	Total Snettisham				78
5	Gold Creek Hydro	1904 *		1	1
6	Annex Creek Hydro	1915		4	4
7	Salmon Creek Hydro	1984 **		5.5	5.5
8	Gold Creek Internal Combustion:				
9	Enterprise Diesel (#1)	1952		1	
	Enterprise Diesel (#2)	1954		1	
10	Enterprise Diesel (#3)	1961		3	
	Fairbanks Morse (#4)	1963		1	
11	Fairbanks Morse (#5)	1966		1	
	Total Gold Creek IC				7
12	Lemon Creek Internal Combustion:				
13	GM Diesel (#1)	1969		3	
	GM Diesel (#2)	1969		3	
14	GM Diesel (#3)	1974		3	
	GM Diesel (#7)	1983		3	
15	GM Diesel (#8)	1984		3	
	GM Diesel (#9)	1984		3	
16	GM Diesel (#10)	1984		3	
	GM Diesel (#11)	1984		3	
17	GM Diesel (#12)	1985		3	
	Pratt-Whitney Gas Turbine (#5)	1980		18	
18	Pratt-Whitney Gas Turbine (#6)	1983		18	
	Total Lemon Creek IC				63
19	Auke Bay Internal Combustion:				
20	Enterprise Diesel (#4)	1983		3	
	Solar Centaur Gas Turbine (#13)	1993		3	
21	Pratt-Whitney Gas Turbine (#14)	1994		23	
	Total Auke Bay IC				29
22	Total Capacity			187.5	188
23					
24	+ Nameplate Capacity				
	* Firm only during summer and fall months				
25	** Maximum Capacity Output Limited to 5.5 mW due to Penstock Limitations				
26	(Source = 1999 AEL&P Annual Operating Report)				

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ALASKA ELECTRIC LIGHT AND POWER COMPANY
 1999 TEST YEAR

SUMMARY OF EXISTING RATES COMPARED WITH PROPOSED RATES
 (Adjusted for Staff recommendations and foregoing Schedule 10D increase)

RATE DESCRIPTION	EXISTING RATES		PROPOSED RATES		ABSOLUTE \$ CHANGE		PERCENTAGE CHANGE		
	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	
10 Residential									
Energy charge, cents per KWH	8.86	7.28	9.22	7.58	0.36	0.30	4.06%	4.12%	
Customer charge, \$ per month	8.50	8.50	8.50	8.50	-	-	0.00%	0.00%	
10D Residential with demand									
Energy charge, cents per KWH	4.48	3.91	4.48	3.91	-	-	0.00%	0.00%	
Customer charge, \$ per month	11.00	11.00	11.00	11.00	-	-	0.00%	0.00%	
Demand charge, \$ per month	8.58	5.19	8.58	5.19	-	-	0.00%	0.00%	
20 Small Commercial									
Energy charge, cents per KWH	8.58	6.82	8.93	7.10	0.35	0.28	4.08%	4.11%	
Customer charge, \$ per month	18.00	18.00	18.00	18.00	-	-	0.00%	0.00%	
20D Small Commercial with demand									
Energy charge, cents per KWH	4.93	4.37	5.13	4.55	0.20	0.18	4.06%	4.12%	
Customer charge, \$ per month	26.00	26.00	26.00	26.00	-	-	0.00%	0.00%	
Demand charge, \$ per month	9.45	6.32	9.83	6.58	0.38	0.26	4.02%	4.11%	
24 Large Commercial									
Energy charge, cents per KWH	4.54	4.25	4.72	4.42	0.18	0.17	3.96%	4.00%	
Customer charge, \$ per month	95.00	95.00	95.00	95.00	-	-	0.00%	0.00%	
Demand charge, \$ per month	10.61	6.77	11.04	7.04	0.43	0.27	4.05%	3.99%	
41 Manufacturing									
Energy charge, cents per KWH	4.87	4.42	5.07	4.60	0.20	0.18	4.11%	4.07%	
Customer charge, \$ per month	95.00	95.00	95.00	95.00	-	-	0.00%	0.00%	
Demand charge, \$ per month	8.47	6.77	8.81	7.04	0.34	0.27	4.01%	3.99%	
46 STREETLIGHTS - Rate per year									
100 Watt, per light	96.59	96.59	92.41	92.41	(4.18)	(4.18)	-4.33%	-4.33%	
150 Watt per light	144.83	144.83	138.56	138.56	(6.27)	(6.27)	-4.33%	-4.33%	
175 Watt per light	169.00	169.00	161.68	161.68	(7.32)	(7.32)	-4.33%	-4.33%	
200 Watt per light	193.06	193.06	184.70	184.70	(8.36)	(8.36)	-4.33%	-4.33%	
250 Watt per light	225.70	225.70	215.92	215.92	(9.78)	(9.78)	-4.33%	-4.33%	
400 Watt per light	298.05	298.05	285.14	285.14	(12.91)	(12.91)	-4.33%	-4.33%	
1000 Watt per light	592.95	592.95	567.26	567.26	(25.69)	(25.69)	-4.33%	-4.33%	

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RATE DESCRIPTION	EXISTING RATES		PROPOSED RATES		ABSOLUTE \$ CHANGE		PERCENTAGE CHANGE	
	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER
91 Off-Peak Service								
Customer Charge:								
Rate 10, \$ per month	\$7.50	\$7.50	\$7.50	\$7.50	-	-	-	-
Rate 20, \$ per month	14.00	14.00	14.00	14.00	-	-	-	-
Rate 24, \$ per month	25.00	25.00	25.00	25.00				
Energy charge cents per KWH	5.65	5.91	5.65	5.65	5.90	5.90	4.06%	4.06%
92 Residential Heat Pump Service								
Energy charge, cents per KWH	3.80	3.44	3.95	3.58	-	-	4.06%	4.06%
Customer charge, \$ per month	10.50	10.50	10.50	10.50	-	-	0.00%	0.00%
Demand charge, \$ per month	7.35	4.49	7.65	4.67	-	-	4.06%	4.06%
Juneau Ready Mix Special Contract Amendment #2:								
Energy charge, cents per KWH	.0781	.0781	.0813	.0813	0.32	0.32	4.06%	4.06%
20D Small Commercial with demand								