

1 **STATE OF ALASKA**

2 **THE REGULATORY COMMISSION OF ALASKA**

3 Before Commissioners:

Robert Mr. Pickett, Chair
Kate Giard
Paul F. Lisanke
T.W. Patch
Janis W. Wilson

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7 In the matter of the Tariff Revision, Designated as)
TA381-1, Filed ALASKA ELECTRIC LIGHT)
8 AND POWER COMPANY For Interim and)
Permanent Rate Increases)

TA 381-1
U-10-___

9
10 **PREFILED DIRECT TESTIMONY OF DAVID A. GRAY**

11 **Q1. Please state your name and address.**

12 A1. My name is David A. Gray. My business address is 1601 Fifth Ave, Suite 1100, Seattle,
13 Washington 98101.
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16 **Q2. What is your position and by whom are you employed?**

17 A2. I am a Vice President of CH2M HILL and am the Principal in Charge of the firm's
18 Downtown Seattle Office. The firm provides multidisciplinary consulting services in a
19 diversity of markets globally. Together with our construction and operations business,
20 the firm has a staff of 24,000 employees. We have offices in Anchorage, throughout the
21 United States, and in 115 other countries worldwide.
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24 **Q3. Was the cost of service and rate study submitted by AELP in this docket prepared**
25 **by you or under your direction?**

26 A3. Yes.
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Q4. What is your educational background and work experience?

A4. My educational background and work experience is summarized in my resume in Exhibit DAG-1.

Q5. Have you previously testified before the Regulatory Commission of Alaska or its predecessor, the Alaska Public Utilities Commission?

A5. I appeared before the Alaska Public Utilities Commission on behalf of Alaska Electric Light and Power (AELP) in rate cases during the 1980s. This included testifying on cost of service and rate studies submitted to the APUC in Dockets U-81-44, U-84-50, and U-85-49. Also on AELP's behalf, I testified in APUC Docket U-83-16 regarding AELP's application for an electric heat moratorium. Separately, I appeared on behalf of Golden Valley Electric Association in Dockets U-85-03 and U-92-11 regarding power requirements issues associated with that utility's need for new power generation resources.

Q6. What is your assignment in this proceeding?

A6. AELP asked me to update its cost of service and rate study for use in this proceeding and respond to any questions about the study. The analysis in the study is based on operating and financial information provided by AELP including data separately filed with the Commission in this docket.

1 **Q7. Please describe the methods employed in preparation of the cost of service study.**

2 A7. The methods are essentially the same as those CH2M HILL developed for AELP in 1984
3 for use in that year's rate case (Docket No. U-84-50). Since that time, AELP has updated
4 the analyses in each succeeding rate case using the same general approach. That
5 approach has been generally accepted by the Commission; interveners in AELP's last rate
6 case also generally accepted the cost of service method.
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9 The method employed by AELP is a fully allocated, seasonal, average cost of service
10 study. It generally complies with the tenets of the National Association of Regulatory
11 Commissioner's *Electric Utility Cost Allocation Manual*, January 1992, and the earlier
12 version of the manual published in 1973. It also complies with requirements for cost of
13 service methods as specified in the Alaska Administrative Code (3 AAC 48.540). The
14 general method is described within the "Cost of Service Methodology" text starting on
15 page 3 of the cost of service study. This is essentially the same description as was filed
16 with AELP's cost of service study in 1984.
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19 **Q8. Please describe the test year data utilized in this cost of service study.**

20 A8. The test year data used for the cost of service study is the same as that used by AELP to
21 calculate the overall revenue requirements for AELP's proforma 2009 test year. Cost
22 data included in the cost of service study tie directly to the revenue requirement study. In
23 cases where detailed cost account data were needed, the detailed data were also provided
24 by AELP. We also used operating data supplied by the utility.
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28 PREFILED DIRECT TESTIMONY OF DAVID A. GRAY

Tariff Advice No. 381-1

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1 **Q9. Please describe the contents of AELP's 2009 cost of service study.**

2 A9. An index to the schedules contained in the cost of service study is provided on page 2 of
3 the study. As previously mentioned, a discussion of the cost of service study
4 methodology is provided starting on page 3. Starting at page 10 are sales and demand
5 information that is used in the study. The cost of service study, including all calculation
6 schedules, starts at page 14. That study is followed by summary results for cost of
7 service calculations using alternative cost allocation methodologies. Those summaries
8 including a comparison with results of AELP's base cost of service study run from page
9 38 through page 43. Starting at page 44 are summaries of current and proposed
10 permanent and interim rates, followed by typical bill analyses for permanent rates,
11 starting at page 49. Finally, starting at page 72 are the Commission's cost of service
12 study regulations with references to where the required information is located in the cost
13 of service study.
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17 Within the AELP's base cost of service study, starting at page 16, there are twelve active
18 cost of service calculation schedules. As noted in the index, Schedules 6-8 and 12-14 are
19 inactive and therefore are not shown. Schedule 1 summarizes the results of the cost of
20 service study. For each class, it provides information on revenues, rate base, overall
21 revenue requirements, and the portion of revenue requirements needed from firm sales. It
22 also shows how the cost of service for each rate class compares to revenues from AELP's
23 current and proposed rates.
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28 **PREFILED DIRECT TESTIMONY OF DAVID A. GRAY**

Tariff Advice No. 381-1

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Sales revenues from each class under existing rates are shown at the top of the schedule (Line 4). These sales are referred to in the study as “firm” sales. They include all sales made under standard AELP rate schedules 10 (Residential), 20 (Small Commercial), 24 (Large commercial), 41 (Manufacturing), and 46 (“Dusk to Dawn Lighting” referred to in the cost of service study as “Street Lights”). In addition, they include sales made to special, small rate classes including Rate Schedules 29 (fish hatchery at Snettisham), 91 (Off-Peak), and 92 (Residential Heat Pump). Rate Schedule 29 has 1 customer, Rate Schedule 91 has 30 customers, and Rate Schedule 92 has 6 customers. Because these rate classes are so small, they were rolled in with the larger classes in the cost of service study. While we have characterized all of these rates as “firm,” Rate Schedule 29 can be interrupted if there is an outage of the Snettisham system and Rate Schedule 41 can be interrupted during the winter season (most of the load for the single customer in this class is in the summer season.)

Schedule 1 also shows a summary of the allocation of other operating revenues to each class (Line 5). Those other operating revenues reduce the amount of revenues that need to be generated from firm sales and thereby keep rates lower than they would otherwise need to be.

Components that comprise AELP’s overall revenue requirement are shown in Lines 12 through 17 of Schedule 1. The portion of those requirements to be recovered through sales to firm customers is calculated as shown in Lines 20 through 22. The difference

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between those revenue requirements from firm sales and revenues from current rates is shown in Lines 26 and 27.

Revenues from an across-the-board increase to energy and demand charges are shown in Lines 30 through 35. Revenues and their relationship to revenue requirements from sales to each class are shown in Lines 31 and 32, respectively, assuming that AELP were to set rates to fully recover its revenue requirement. At Lines 34 and 35, revenues and their relationship to revenue requirements from sales to each class are shown based on AELP's proposed rates.

The detail for existing revenue is shown in Schedule 2. Revenues generated from sales to each class are naturally credited to each respective class. The largest other operating revenues are the \$6.65 million in revenues from interruptible sales to Greens Creek. Because those revenues are generated based on the sale of surplus hydroelectric generation from AELP, they were credited back to the respective customer classes on the same basis that hydroelectric generation costs were allocated to the AELP customer classes.

Schedules 3, 4, and 5 provide allocation of test year expenses including operating and maintenance expenses, depreciation expense, and taxes (other than income taxes), respectively.

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Schedule 9 shows a calculation and allocation of AELP's rate base. It is based on information from Schedules 10, 11, and 15. Schedule 10 shows the allocation of gross plant, by plant account, and Schedule 11 shows the allocation of accumulated depreciation associated with those accounts. Schedule 15 shows the allocation of the other rate base items. Salaries and wages are presented in Schedule 16.

Allocation factors used in the cost of service analysis are provided in Schedule 17 and 17a. Schedule 17 shows the numerical bases for the allocation factors and Schedule 17a translates those data into ratios used to allocate costs and revenues credited to AELP's various customer classes.

Q10. Did you prepare any alternative cost of service analyses?

A10. Yes, as required by 3 AAC 48.540, I prepared two other cost of service analyses. The first additional analysis used the peak responsibility method to allocate demand-related generation and transmission costs to AELP's customer classes. Summary results of that analysis are shown at page 39 of the study. The second alternative analysis used the average and excess method to allocate demand-related generation and transmission costs to AELP's customer classes. Summary results of the second analysis are shown at page 41 of the study. In both of these alternative analyses, demand-related distribution costs were allocated on the basis of the class non-coincident peak demand. A comparison of the results of the alternative analyses is shown at page 43 of the study.

1 In contrast to those specific alternative analyses, AELP has for decades used the peak
2 responsibility method for allocating demand-related generation costs, the average and
3 excess method for allocating demand-related transmission costs, and non-coincident
4 demand for allocating distribution-related costs. AELP used that same approach in the
5 2009 cost of service study.
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8 **Q11. How do the rate class revenues from existing rates compare to revenue**
9 **requirements calculated in the cost of service study?**

10 A11. That information is provided on lines 26 and 27 of Schedule 1 of the cost of service study
11 (page 16). As shown in line 27, AELP's revenue requirements are 34.2 percent higher
12 than revenues at existing rates. The cost of service analysis shows that this difference
13 ranges from 25.6 percent to 38.6 percent with the exception of one outlier, Rate 41.
14 Revenue requirements for Rate 41, Manufacturing, are 395 percent higher than revenues
15 from existing rates.
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18 **Q12. Why is the relationship between existing revenue and cost of service for the**
19 **Manufacturing rate class (Rate Schedule 41) so different from that of the other rate**
20 **classes?**

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22 A12. In 2009, there was only one customer on this rate. That customer had an annual load
23 factor of only 2 percent and consumed 72 percent of its annual power requirements in just
24 a three month period. As a result, there were relatively little revenues from this customer
25 during nine months of the year. Given that demand-related costs are normally recovered
26 by charging for billing demands over the course of 12 months, revenues from this
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1 customer class lagged seriously behind its calculated revenue requirements. A practical
2 solution to this aberration is discussed later in my testimony.

3
4 **Q13. What general method is AELP proposing to use in increasing its firm rates?**

5 A13. AELP is proposing to increase firm rates on an across-the-board basis. Specifically, it
6 proposes to leave existing customer charges unchanged and increase all energy and
7 demand charges as well as monthly street lighting charges by a uniform percent.
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10 **Q14. If AELP were to increase its rates using that method to fully recover its revenue**
11 **requirements (cost of service) from firm sales, what increase would be required and**
12 **how would revenues from the rates compare to revenue requirements for AELP's**
13 **various customer classes?**

14
15 A14. To meet its revenue requirements from firm sales, AELP would have to raise its rates by
16 34.2 percent. Using the across-the-board methodology, the ratio of revenues to revenue
17 requirements from firm sales would be as shown in Schedule 1, Line 32 of the cost of
18 service study. Except for Rate 41, revenues would be quite close to revenue
19 requirements. The ratio for Residential would be 96.4 percent, meaning that the
20 Residential class would be paying 96.4 percent of its allocated costs. Ratios for other
21 classes would be 106.4 percent for Small Commercial, 102.8 percent for Large
22 Commercial, and 98.9 percent for Street Lights. Manufacturing would be an outlier at
23 24.5 percent for reasons previously discussed.
24

25
26 **Q15. What rates are being proposed?**

1 A15. AELP's existing and proposed rates for rate schedules 10, 20, 24, 41, 46, 91, and 92 are
2 shown on pages 45 and 46 of the cost of service study. Pages 46 and 47 show AELP's
3 proposed interim rates.

4
5 As previously noted, Rate Schedule 29 is a special rate for a single, fish-hatchery
6 customer at Snettisham. The rate for that service is set by contract and is scheduled to
7 increase from 3.38 cents per kWh to 4.75 cents per kWh on May 1, 2010. Therefore, no
8 rate change is proposed for that rate schedule as part of this rate filing.
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11 **Q16. How were proposed rates prepared?**

12 A16. AELP is proposing to increase rates 10, 20, 24, 41, 46, 91, and 92 on an "across-the-
13 board" basis. Specifically, AELP proposes to adjust its rates by raising all demand,
14 energy, and monthly street lighting charges by 20.0 percent for interim rates and by 24.0
15 percent for permanent rates.
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18 **Q17. What revenues are produced from the proposed rates?**

19 A17. Revenues to be produced from each customer class under proposed interim and
20 permanent rates were calculated as shown on Exhibit 3 of AELP's Tariff Advice Letter
21 No. 381-1. A total of \$31,761,297 would be produced from interim rates and
22 \$32,749,152 would be produced from permanent rates. Revenues from AELP's proposed
23 permanent rates for each rate class are also shown on Schedule 1 of the cost of service
24 study at Line 34. Proposed permanent rates would increase annual revenues from firm
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1 sales by \$5.9 million, or 22.1 percent. This will be about \$3.2 million, or 9.0 percent,
2 below AELP's overall revenue requirements from sales.

3
4 **Q18. Under the proposed permanent firm rates, how do revenues from sales for each**
5 **class compare with their respective revenue requirements (cost of service)?**

6
7 A18. That information is also shown in Schedule 1 of the Cost of Service Study at Lines 22,
8 34, and 35. Line 35 reports the ratio of revenues from proposed permanent rates to
9 revenue requirements from firm sales. Since the proposed rates generate system-wide
10 revenues that are only 91.0 percent of total revenue requirements from sales, the system-
11 wide ratio is also 91.0 percent. The ratios of proposed revenues to revenue requirements
12 for AELP's individual rate classes are quite close to the system-wide average (with the
13 exception of Rate Schedule 41). They vary by only small amounts from the average:
14 Residential (Rate Schedule 10), 3.1 percentage points (91.0 percent minus 87.9 percent);
15 Small Commercial (Rate Schedule 20), 5.9 percentage points; Large Commercial (Rate
16 Schedule 24), 2.1 percentage points; and Street Lights (Rate Schedule 46), 1.5 percentage
17 points. That indicates that the interclass allocation of costs that will result from an
18 across-the-board increase in demand and energy charges will generally reflect AELP's
19 cost of service. The obvious exception is Manufacturing (Rate Schedule 41) where the
20 ratio of revenue from proposed rates to revenue requirements varies from the average by
21 66.5 percentage points.
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1 **Q19. What is the solution to this disparity between revenues and revenue requirements**
2 **for the Manufacturing rate schedule?**

3 A19. Given that there is only one customer on Rate Schedule 41 and that the rates are close to
4 those of Rate Schedule 24, AELP proposes to close the rate to new customers and
5 transition the existing customer on Rate Schedule 41 to Rate Schedule 24. This would
6 consist of notifying the customer of the plan to transfer its service to Rate Schedule 24
7 and then doing so effective January 1, 2012. AELP plans to prepare appropriate revisions
8 to Rate Schedule 41 to effect these changes and submit them to the Commission through
9 a separate tariff advice letter.
10

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12 **Q20. You mentioned that the charges included in Rate Schedule 41 are close to those in**
13 **Rate Schedule 24. How much will the shift from Rate Schedule 41 to Rate Schedule**
14 **24 impact the Rate 41 customer's annual power bill?**

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16 A20. Under 2009 test year conditions, the customer's bill under Rate Schedule 24 would have
17 been six percent higher than the amount paid under Rate Schedule 41. So, the effect of
18 the transition would be to increase the customer's annual bill by an additional six percent,
19 all other factors being equal.
20

21
22 **Q21. As you have noted, AELP is proposing to increase its rates on an across-the-board**
23 **basis. Do you agree with that proposal?**

24 A21. Yes, I do. The interclass allocation of costs in AELP's proposed rates is very close to the
25 allocation that would result from precise implementation of cost of service based rates.
26 As previously mentioned, the proposed permanent rates vary from the proposed 91
27

1 percent recovery of revenue requirements by only small amounts, with the exception of
2 the Manufacturing rate, which will be terminated. The variances range from 3.1
3 percentage points below the 91 percent cost recovery level for the Residential class (at
4 87.9 percent) to 5.9 percentage points above the 91 percent cost recover level for the
5 Small Commercial class (at 96.9 percent).
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8 The only rate that is not reasonably in sync with its revenue requirement is the
9 Manufacturing rate. AELP proposes to remedy that imbalance by closing that rate to new
10 customers and entirely eliminating the rate effective January 1, 2012. This plan is
11 prudent in that it removes the rate and its imbalance but does so in such a way that its
12 sole customer is notified of the impending change in a timely manner and can prepare for
13 the change.
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16 **Q22. What will be the impact on customers from the proposed rate increase?**

17 A22. The impact on customers of varying size and load characteristics is shown starting at
18 page 49 of the cost of service study. Those pages contain a typical bill analysis for each
19 customer class. Specifically, they show the amount of increase under proposed rates at
20 varying levels of energy consumption for all classes and for different combinations of
21 energy and demand for demand-metered customers who take service under Rates 20, 24,
22 and 41.
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25 **Q23. Does this conclude your testimony?**

26 A23. Yes, it does.
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28 PREFILED DIRECT TESTIMONY OF DAVID A. GRAY

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David A. Gray

Vice President
CH2M HILL

Education

B.A., Economics and Mathematics, Western Washington University; Graduate Studies, Economics and Business Administration, University of Washington and Western Washington University

Distinguishing Qualifications

- Advisor to domestic and international clients on energy and utility economics and finance
- Experienced program manager with a long history of success in delivering innovative and effective analyses and recommendations to clients
- Expert in utility rates, privatization, energy project development, energy efficiency, planning and forecasting, and market evaluation

Relevant Experience

Mr. Gray is a management consultant with CH2M HILL's Energy and Industrial Systems Business Group in Seattle, Washington. He has more than 35 years of experience advising domestic and international clients on a wide range of energy- and utility-related issues. Mr. Gray has developed trusted relationships with a number of clients, delivering projects efficiently and effectively.

Representative Project Experience

Pricing

Project Manager; Cost of Service and Ratemaking; Omaha Public Power District. For the past 15 years, has provided on-going advice to the Board of Directors of the Omaha Public Power District regarding cost of service, rate, management, and related financial issues. Provides critical review of District rate proposals and pricing practices. In many cases, this review leads to collaboration on alternative approaches to achieve rate proposals that meet criteria of being fair, reasonable, and non-discriminatory.

Task Manager; Wholesale Rate Impact Evaluation; Bonneville Power Administration. Conducted an evaluation of the wholesale and retail impacts of a wide range of traditional and innovative rate designs for power supply and wheeling services.

Project Manager; Cost of Service and Ratemaking; Alaska Electric Light and Power Company. Conducted cost of service and rate design studies. Developed innovative rates in support of the utility's load management program.

Project Manager; Cost of Service and Rate Studies; Various Utilities; Washington, Alaska, California; American Samoa, Northern Mariana Islands. Prepared cost-of-service and rate studies for utilities in Washington, Alaska, California, American Samoa, and the Commonwealth of the Northern Mariana Islands; has been involved in rate hearings throughout the United States.

Energy Efficiency

Program Manager; Energy Efficiency Program; Confidential Fortune 100 Company. Managing the on-going energy efficiency program for a Fortune 100 company in the United States. The work has included conducting energy audits at about 130 major facilities as well as oversight of energy audits conducted at hundreds of other sites by other energy auditors. An interactive web interface was developed to facilitate financial evaluation and prioritization of energy savings measures, tracking of projects from inception to completion, and reporting of program costs, energy savings, and related financial accomplishments. The program work provided for this client also included incorporation of an energy efficiency component to the company's construction guidelines, and management of a LEED® certification project.

Project Manager; Energy Conservation Program; Golden Valley Electric Association (GVEA). Prepared and helped implement a utility-wide conservation plan. The plan won a National Energy Award from the United States Department of Energy. It includes three components to induce GVEA customers to install conservation measures. Home Sense is an in-home audit program where customers receive energy efficient products installed on the spot. Builder Sense offers rebates for "building in" energy efficiency during new home construction. Business Sense offers rebates to commercial customers for energy efficient lighting. The planned conservation program was implemented and is now fully operational.

Project Manager; Conservation and Load Management Plans; Alaska Electric Light and Power Company. Developed load management and conservation plans ranging from conceptual design to implementation plans. The conservation plan included development of program goals, assessment of market conditions for energy conservation, and a three-stage strategy for implementation. The market assessment included residential and commercial end-use customer surveys and assessment of market potential at a range of price points. Plans developed for this utility also included rate design for marketing power during periods when surplus, low-cost power is available; and conserving, load shedding, and substituting fuels during shortages or periods when only high-cost power is available at the margin.

Project Manager; Generic Investigation; Kansas Corporation Commission. Planned the Kansas Corporation Commission's formal investigation into electric utility load management, rate design, and conservation.

Energy Project Development

Program Manager; Solar Power Project Development; Confidential Client. Managed a program for a confidential client that included guiding development of a 1 MW solar power project. The project was completed within a year of initial investigation and is now operational, providing energy savings to the client relative to standard rates charged by the local utility.

Project Manager; Alaska Gas Pipeline Investment Evaluation; State of Alaska Department of Revenue. Conducted an evaluation of the risks, rewards, and regulatory constraints associated with financial participation in the proposed \$15-billion Alaska gas pipeline project. As part of this work, developed a financial model that assessed the impact uncertainties would have on projected rates of return and tariff levels. Key uncertainties included market conditions, construction costs, and delays that might affect the project's completion date. The model also evaluated the impact tax-exempt financing would have on project feasibility. Risk profiles were developed to show the likely range of project returns based on key uncertainties associated with the project.

Project Manager; Snettisham and Lake Dorothy Hydroelectric Projects; Alaska Electric Light and Power (AELP) Company and the Alaska Industrial Development and Export Authority (AIDEA). Assisted Alaska Electric Light and Power Company and the Alaska Industrial Development and Export Authority acquire the Snettisham Hydroelectric Project in Alaska. This was one of the first acquisitions of a significant Federal energy generation facility. Prepared the consulting engineer's report for the bond statement used to secure \$100 million to finance the acquisition. The report included analysis of risks associated with project operation as well as an associated power sales agreement.

Also prepared the feasibility study for a \$50 million revenue bond issue primarily to finance construction of the Lake Dorothy Hydroelectric Project. The study included analysis of construction, market, and system failure risks as well evaluation of the financial strength of the utility and its ability to withstand lost revenues from unlikely but possible cost overruns, changes in market conditions, and system failures.

Project Manager; Economic/Financial Feasibility Study; Railbelt and Copper Valley; Alaska. For a blue-ribbon committee appointed by the Governor of Alaska, completed both an economic and a financial feasibility study for a new transmission line planned to connect the Railbelt and Copper Valley regions in Alaska. This work included evaluation of future electric load developments in the region, alternative power supply projects, and generation efficiencies gained through linking the two regions with the proposed transmission line.

Task Manager, Economic and Financial Planning for Solar Project Development; Santa Clara County, California. Prepared an analysis of the economic feasibility and financing options for solar development at numerous locations in Santa Clara county.

Project Manager; Network Development; Seattle City Light; Seattle, Washington. Advised Seattle City Light on approaches needed to evaluate the costs, risks, pricing, and overall feasibility of a network development in the South Lake Union area of Seattle. The analysis

supported SCL's communications with key project stakeholders regarding the likely rate for network service.

Project Manager; Cogeneration Project; Snohomish County Public Utility District (PUD). Evaluated the feasibility of a \$90 million bond issue for a cogeneration facility fueled by wood waste. The project included a detailed wood waste market study and the ability of the PUD to float tax-free financing for the project. For other revenue bonds issued by the PUD, evaluated bond feasibility with focus on financial forecasts for the utility.

Project Manager; Municipal Electric Utility Evaluation; City of Spokane. with an evaluation of optional uses for power generated at its Upriver Dam Hydroelectric Project and its Waste-to-Energy Facility. The study evaluated the basis for the rates charged to the City for power supplied by the existing electric utility, Avista, and compared the power supply cost component of those rates to the revenue the City could reasonably expect to obtain from sale of power from its two generating resources. Steps needed to acquire the existing system and establish a new public utility were delineated. The costs of supplementing the City's generating resources for full and reliable service and the cost of replacing or acquiring Avista's existing distribution system in Spokane were also considered.

Planning and Forecasting

Project Manager; State Energy Plan; Alaska Industrial Development and Export Authority, State of Alaska. With the Alaska Industrial Development and Export Authority, prepared the rural region section of the State of Alaska Energy Plan. For Alaska's rural communities, prepared an assessment of the energy characteristics, costs, and needs of rural communities. This included evaluation of electric utility management, service reliability, service affordability, and the power cost equalization program. Based on these evaluations, challenges facing rural communities and possible solutions to those challenges were identified. These included opportunities and possible solutions in terms of fuel cost reductions, efficiencies from technological improvements, efficiency incentives, economies of scale, modernization of administrative practices, improved system reliability, and improved operation and management practices.

Project Manager; Energy Plan; Seattle-Tacoma International Airport (Sea-Tac); SeaTac, Washington. Prepared energy supply strategy for Seattle-Tacoma International Airport, which recently obtained open access to unregulated power supplies. The study included development of a profile of energy use at the Airport, review of the regional energy market structure and long-range trends in cost and reliability, evaluation of energy options with the Airport's current electric and natural gas supplier, and analysis of generation options available to the Airport. Based on that analysis, short-, intermediate-, and long-term power supply and conservation strategies were developed and reported to Airport management. In a follow-on contract, he assisted the Airport in its implementation of recommended strategies and procurement of a long-term energy supply.

Project Manager; Integrated Resource Plan; Golden Valley Electric Association. Managed development an integrated resource plan and power requirements study for Golden Valley

Electric Association. The project included analysis of uncertainties and led to development of the utility's conservation program and new power supply development.

Privatization

Project Manager; Utility Privatization; U.S. Air Force; U.S. Air Force Bases throughout the United States. Advised the U.S. Air Force in its development of an overall approach to privatizing the utility systems on its bases throughout the United States. This included strategically establishing the Air Force approach to risk analysis, initial feasibility assessment, acquisition document development, and financial evaluation of privatization proposals. Developed a financial model that the Office of the Secretary of Defense adapted for use for assessment of bids at all DOD utilities. Authored portions of the Air Force's guidance manual for evaluating utility privatization opportunities. He also managed the first utility privatization study conducted by the Air Force at Kelly Air Force Base. The work included development of risk profiles associated with project benefits and costs.

Task Manager; Privatization Bids; Miscellaneous Utilities. Assisted a number of utilities prepare in-depth proposals to privatize utility systems at military bases throughout the United States. Several of the proposals were successful and utility system ownership transferred to the client; others are still in negotiation.

Project Manager; Utility Privatization; Commonwealth of the Northern Mariana Islands. Prepared an extensive report for the Commonwealth on deregulation and the feasibility of privatization of government electric, water, and wastewater utilities. This work included detailed financial modeling, evaluation of legal and institutional barriers, implementation strategies, and rate impact analysis.

Market Evaluation

Project Manager; Planned Community; California. Evaluated the financial feasibility and rate requirements for a new utility to serve a new, planned community in California.

Project Manager; Segmented Housing Market Analysis; U.S. Army Corps of Engineers. Managed a major study of the housing market in 23 European communities to determine the level of housing availability for U.S. military personnel and the need for new construction to meet housing shortages. The Corps of Engineers rated work performed on this project as "Excellent".

Project Manager; Secondary Energy Price Computer Model; Seattle City Light. Developed a computer model that evaluated and projected secondary energy prices in the Pacific Northwest. The model provided for evaluation of uncertainties including regional water conditions, load development, and resource availability in both the short and long term.

Project Manager; Bond Feasibility; Port of Tacoma; Tacoma, Washington. Managed the consulting engineer's report for two major revenue bonds issued by the port. The reports

reviewed the feasibility of bonds used to construct new facilities at the port. Analyses included review of project costs, market analyses, and financial forecasts for the port.