SCREENING REPORT FOR ALASKA RURAL ENERGY PLAN

Prepared for the

Alaska Industrial Development and Export Authority

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Abbreviations

AC	Alaska Commercial Company
ACDC	Alaska Community Development Corporation
ACEEE	American Council for an Energy Efficient Economy
ADEC	Alaska Department of Environmental Conservation
ADOT&PF	Alaska Department of Transportation and Public Facilities
AP&T	Alaska Power and Telephone
AEA	Alaska Energy Authority
AHFC	Alaska Housing Finance Corporation
AIDEA	Alaska Industrial Development and Export Authority
ANA	Administration for Native Americans
ANICA	Alaska Native Industries Cooperative Association
ASCC	Alaska System Coordinating Council
BESS	battery energy storage system
Btu	British thermal unit
CDBG	Community Development Block Grant
CEC	Cordova Electric Cooperative
DC	direct current
DCED	Alaska Department of Community and Economic Development
DCRA	Alaska Department of Community and Regional Affairs
DHW	domestic hot water
DNR	Alaska Department of Natural Resources
DOE	Alaska Department of Community and Regional Affairs, Division of Energy
DOP	percentage of outages that are distribution-caused
EPA	U.S. Environmental Protection Agency
EPS	Electric Power Systems, Inc.
ESS	energy storage system
FAA	Federal Aviation Administration
GEC	Global Energy Concepts
GOP	percentage of outages that are generation-caused
GVEA	Golden Valley Electric Association
HBC	Humpback Creek Power Plant
HUD	U.S. Department of Housing and Urban Development
ICDBG	Indian Community Development Block Grant
ICRC	Integrated Concepts and Research Corporation
ISER	University of Alaska Anchorage, Institute of Social and Economic Research
kV	kilovolt
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
NA	not applicable, not available
NARUC	National Association of Regulatory Commissioners
NETS	Neubauer Engineering and Technical Services
NO_x	nitrous oxide
NTHC	Northwest Territories Housing Corporation

NWT	Northwest Territories
O&M	operations and maintenance
OPIS	Oil Price Information Service
PCE	Power Cost Equalization
PLC	programmable logic control
PV	photovoltaic
RACE	Rural Alaskans Conserve Energy
RTED	real-time economic dispatch
RurAL CAP	Rural Alaska Community Action Program
SCADA	supervisory control and data acquisition
SIR	service interruption rate, all types (hours per year per consumer)
SWGR	single-wire ground return
THREA	Tlingit-Haida Regional Electrical Authority
USCG	U.S. Coast Guard
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USPS	U.S. Postal Service
V	volt
VA	volt-ampere
VAr	volt-ampere reactive
VSW	Village Safe Water
VUE	value of unserved energy
W	watt
WACC	weighted average cost of capital
WAVE	Western Alaska Village Enterprise

Executive Summary

This report has been prepared for the Alaska Industrial Development and Export Authority (AIDEA), the U.S. Department of Agriculture – Rural Development, and the Denali Commission, and is one component of the Alaska Rural Energy Plan. Phase 1 of the Rural Energy Plan was completed in 1999 and served primarily to identify a long list of possibilities for addressing rural energy problems. This report builds on Phase 1 by subjecting those possibilities to a screening analysis, the product of which is a short list of strategies that hold the most promise for reducing the cost or improving the reliability of energy supply in rural Alaska. This short list of strategies will be evaluated in more detail as work on the Rural Energy Plan continues.

Most of the strategies and technologies considered in this screening analysis can be grouped in the following categories:

- Upgrades to conventional diesel power plants
- Strategies to reduce delivered fuel prices
- Energy conservation and efficiency measures for end-users
- Alternative energy technologies
- Waste heat recovery

Table ES-1 shows the strategies and technologies selected for further study. [1]

Table ES-1. Short List of Strategies and Technologies Recommended for Further Study

Topic Area	Category	Strategy or Technology
Cost of Electricity		
	Diesel Efficiencies	Microprocessor-Based Engine Controls
		Switchgear Improvements
	End-Use Conservation	Lighting Efficiencies
		Appliance Upgrades
	Alternative Energy Technologies	Wind Power [a]
Reliability of Electricity		
		Microprocessor-Based Protective Relays
Cost of Space and Water Heating		
		Waste Heat Recovery Systems
		Insulation and Weatherization
		Heater Upgrades
		Conversion of Electric Water Heaters
		Water Conservation Devices

[a] Although savings in the absence of subsidy have not been confirmed in this screening analysis for current wind projects in Alaska, wind power remains on the short list for further review due to its continuing potential to produce savings in alternate locations where wind speed and other factors are more favorable.

[1] In addition to the topic areas listed in Table ES-1, this report explores a number of financing and construction management options for upgrading rural tank farm facilities. Some of these options are recommended for field testing but not for further analysis at this time.

The only strategies included on the short list are those with the projected capability of producing significant benefit for a large number of people and communities in the near term,[2] assuming that the strategy is implemented aggressively. Benefits considered in the study are projected in the absence of government grants or low interest loans since virtually any alternative can provide benefits to consumers if a large enough subsidy is provided. Strategies not included on the short list may still have considerable merit but, based on the present analysis, appear either to deliver less benefit in the near term or to apply to fewer communities.

Because limited funds were available for this analysis, each alternative was examined only to the point that a conclusion could be reached about its potential to meet the screening criteria. As soon as it became apparent that an alternative would not pass the test, the analysis of that alternative was discontinued. For many alternatives, therefore, the analysis is very brief.

There are two main objectives for the next phase of the Rural Energy Plan:

- Evaluate the short-listed strategies in greater depth to confirm or revise their savings potential and to identify locations or regions where these strategies would be most effectively applied.
- Develop a set of detailed implementation proposals that would broadly disseminate these benefits in rural Alaska as soon as possible.

The next phase of the Rural Energy Plan will also include preparation of a list of specific energy cost reduction projects that are ready to proceed quickly into final design and construction. AIDEA intends to solicit project proposals through issuance of a Request for Proposals in spring 2001. Qualifying proposals, which need not be related to the strategies and technologies recommended in this screening report, will be evaluated by AIDEA and its contractors and will then be considered for funding by the Denali Commission.

[2] For example, to warrant placement on the short list, AIDEA established a guideline that any measure to reduce the cost of electricity should be able to lower rates by at least $0.01 per kilowatt-hour in at least 5 communities within the next 5 years.

1 Introduction

The Alaska Rural Energy Plan is a multiphase endeavor to reduce energy costs and improve energy reliability for rural Alaska residents and communities.[3] This report presents the results of a screening analysis of potential strategies for meeting these goals and represents a portion of the work being undertaken for Phase 2 of the Alaska Rural Energy Plan. The analysis was conducted by Northern Economics, Inc., under contract to the Alaska Industrial Development and Export Authority (AIDEA).

Subsections 1.1 and 1.2 briefly describe the study context, the study team, and the analytical approach. Subsection 1.3 identifies the strategies considered (and the section of this report in which they are addressed) and presents a short list of the most promising approaches and solutions to major energy problems in rural Alaska, as determined by the consulting team.

1.1 Study Context

The following discussion is a synopsis of status of the Alaska Rural Energy Plan.

Plan Components

The State of Alaska, Denali Commission, and U.S. Department of Agriculture (USDA) Rural Development are jointly funding development of a Rural Energy Plan. Due to specific requirements and interests of these three parties, the plan has evolved to encompass four components:

1. **Rural Utility Operations, Maintenance, and Management Study.** USDA had previously decided to fund a study aimed at improving the operations, maintenance, and management of all types of utilities in rural Alaska, including electric utilities, water and sewer, and solid waste disposal. The Institute of Social and Economic Research (ISER) at the University of Alaska Anchorage has been retained to conduct this study, which has been underway for several months.
2. **Rural Electric Utility Condition Assessments.** The State of Alaska, acting through AIDEA, is developing an electric utility database for rural Alaska and expects it to be complete in December 2000. The state already maintains an extensive database on the condition of bulk fuel storage facilities throughout rural Alaska. The Denali Commission values this database for use in decisions about allocating funding for bulk fuel storage upgrade projects. The Denali Commission also funds electric utility upgrade projects in rural communities and therefore asked the state to develop a comparable database on the condition of rural electric utility systems.
3. **Strategies to Address Major Energy Problems in Rural Alaska**. A two-phase study was initiated by the State of Alaska in 1999 to identify major energy problems in rural Alaska and to evaluate and recommend the most promising approaches and solutions. Contractors have been retained to conduct the analysis and AIDEA is providing contract management.

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[3] For the purposes of this report, rural Alaska includes all of Alaska except for the interconnected region of the Railbelt, communities in the Four Dam Pool, Juneau, and Sitka. All communities eligible for the state's Power Cost Equalization (PCE) program are included in this definition of rural Alaska.

Phase 1 was prepared by CH2M Hill. The study listed possible approaches and solutions for each of the following energy sectors and problems:

- For electrical energy, alternatives were identified to address the problems of high cost, service reliability, and inconsistent operations, maintenance, and management of rural electric utilities.
- For space and water heating, alternatives were identified to address the problem of high cost.
- For bulk fuel storage, alternative construction and funding approaches were identified to address the problem of poor condition of facilities.

Phase 2 is subdivided into two parts:

- The study presented in this document is a screening analysis in which each proposed approach and solution is evaluated on a preliminary basis, with the goal of isolating a few of the most promising alternatives for further review and development in the next phase.
- A subsequent, in-depth analysis of approaches and solutions that are carried forward on the short list derived in this screening analysis. This future analysis is intended to further define the potential for significant benefit, to develop detailed implementation plans, and to recommend associated government policies.

4. **Energy Cost Reduction Project List.** The Denali Commission seeks a list of specific energy cost reduction projects that will provide significant near-term benefits to consumers and that are ready to proceed quickly into final design and construction. AIDEA intends to solicit project proposals that meet these criteria through issuance of a Request for Proposals in spring 2001. Qualifying proposals, which need not be related to the strategies and technologies recommended in this screening report, will be evaluated by AIDEA and its contractors and will then be considered for funding by the Denali Commission

Other Related Work

The Alaska Department of Community and Regional Affairs (DCRA), Division of Energy (DOE)[4] prepared a rural energy plan in February 1999. That plan provides background information relevant to the current planning efforts. For example, the 1999 report emphasizes that reliability and cost are the main criteria by which power supply alternatives should be judged in rural Alaska—reliability because of harsh conditions and the consequences of prolonged outages, and cost because retail rates in rural villages are so high. The report notes other factors such as environmental considerations, but describes those factors as secondary to cost and reliability (the two primary factors addressed in the current planning effort managed by AIDEA).

A separate working paper was prepared by the Alaska DOE in May 1999 to supplement the 1999 energy plan. That report, *Rural Energy Plan: Additional Information on Alternative Energy*, provides information on several alternative technologies addressed in this screening analysis.

[4] DOE responsibilities were transferred to the Alaska Energy Authority (AEA) when DCRA was dismantled in late 1999.

In February 1998, the Governor's committee on Power Cost Equalization prepared a working paper that included options for reducing rural power costs (Attachment 1 to DOE, 1999). The options in the paper were divided into the following three categories:

- Reduce non-fuel operating costs
- Reduce fuel costs
- Replace diesel generation with alternative energy

The working paper was a precursor to the 1999 energy plan and set the stage for the current effort.

1.2 Analytical Approach

This section identifies the strategies reviewed in the screening analysis and the team members responsible for each portion of the analysis. Table 1-1 shows the firms on the Northern Economics team and the area(s) of responsibility for each member firm. Team members were assigned areas of research on strategies or technologies in his or her area of specialty. Team members reviewed existing literature related to their topics, conducted interviews with other experts in the field, and prepared the analyses presented in this report. Duplication was allowed in areas of responsibility to take advantage of specialties and experience, and to meet project deadlines.

Table 1-1. Screening Analysis Consulting Team Members and Areas of Responsibility

Firm	Area of Responsibility	
Northern Economics, Inc.	Project Management Fuel Price Strategies	End-Use Conservation Bulk Fuel Storage (Finance)
Electric Power Systems, Inc.	Diesel Efficiencies Recoverable Heat	Reliability
The Financial Engineering Company	Alternative Energy Technologies	
Precision Power, LLC	Diesel Efficiencies Recoverable Heat	Reliability
URS / Dames & Moore	Bulk Fuel Storage (Construction)	

The strategies considered include those presented in the Phase 1 report, as well as any other strategies recommended by team members or other experts interviewed during the project. For example, Electric Power Systems (EPS) and Precision Power were tasked with analyzing strategies that could reduce the cost and improve the reliability of electricity in rural Alaska. Both firms worked with available data on the efficiency and reliability of diesel generating units installed in rural Alaska. Both firms analyzed the strategies recommended in the Phase 1 report to address issues related to the cost and reliability of electricity, developed case studies based on their own experiences to propose new strategies, conducted interviews with other experts at Alaska utilities and elsewhere, and prepared an analysis of each strategy. Draft reports submitted by team members were reviewed by Northern Economics and by AIDEA and then assembled into a single report.

Table 1-2 shows the specific strategies considered in this analysis. Strategies are presented by category, consistent with the RFP and the Phase 1 report. Strategies in the first four categories (diesel efficiencies, fuel price strategies, end-use conservation, and alternative energy) were analyzed for their potential to reduce the cost of electricity in rural Alaska. Strategies in the last category (reliability) were analyzed for their potential to improve reliability of electric utility service in rural Alaska.

In addition to the strategies identified to address issues related to electricity, several strategies were analyzed for their potential to reduce the cost of space and water heating in rural Alaska. These strategies include:

- Heater upgrades
- The use of domestic hot water heater tanks as space heating devices
- Conversion or replacement of electric water heaters with oil-fired heaters
- Water conservation devices (for example, low flow showerheads)
- Substitution of biomass fuels for oil fuels
- Use of waste heat

The report also summarizes strengths and weaknesses of alternative approaches to tank farm construction, and provides a preliminary analysis of the effects of requiring tank farm owners to pay for a portion of tank farm construction costs. Both discussions include a summary of existing conditions or practices.

Table 1-2. Potential Strategies to Reduce the Cost and Improve the Reliability of Electricity

Potential Cost Reduction Strategies				Potential Reliability Improvement Strategies [b]
Diesel Efficiencies	**Fuel Price Strategies**	**End-Use Conservation**	**Alternative Energy**	
Switchgear Improvements Microprocessor-Based Engine Controls Reduce VAr Requirements Life-Cycle Cost Analysis of Transformers Microprocessor-based Protective Relays	Consolidation of Fuel Purchases Alternative Delivery Competition Among Suppliers Enhanced Understanding of Markets Replacing Diesel No.1	Lighting Upgrades Appliance Upgrades	Biomass Natural Gas / Coal Bed Methane Coal Water Fuel Energy Storage Systems Fuel Cells Hydroelectric Interties Microturbines Small Coal Solar Tidal Wind	Microprocessor-Based Protective Relays Line Reclosers

1.2.1 Screening Criteria

The following items identify the criteria used in the screening analysis to develop a short list of the most promising approaches and solutions to major energy problems in rural Alaska:

- The only alternatives included on the short list are those projected to result in **significant benefit** to a **significant number of people and communities** in the **near term**, assuming that the approach is implemented aggressively.
- For alternatives intended to address the high cost of electricity or heat, such benefits must be projected in the absence of government grants or low interest loans, since virtually any alternative can provide benefits to consumers if it is subsidized adequately.

To help define these threshold criteria, AIDEA suggested as a general guideline that any short-listed measure to reduce the cost of electricity should be able to lower rates by at least $0.01 per kilowatt-hour (kWh) (**significant benefit**), in at least 5 communities (**significant number of people and communities**), within a 5-year period (**near term**). For alternatives intended to address the high cost of electricity, benefits must be projected in the absence of government grants or low interest loans, since virtually any alternative can provide benefits to consumers if a large enough subsidy is provided.

Strategies and technologies considered in the reliability and space and water heating categories were recommended for further study if they were economically viable and would produce obvious benefits in the near future.

It is not the intent of AIDEA or the consulting team to rule out strategies that do not meet these criteria from further consideration or support. The intent is to focus on strategies that do meet such criteria and to give them priority consideration.

1.3 Strategies Recommended for Advancement to Next Planning Stage

Table 1-3 identifies the strategies and measures that were considered for this report to address the high cost of electricity and concerns about the reliability of electricity in rural Alaska. Table 1-4 shows the strategies and measures that are considered in this report to address the high cost of space and water heating in rural Alaska, as well as issues related to construction of bulk fuel storage facilities. Both tables show whether the strategy or measure is recommended for more detailed analysis in the next phase of the Rural Energy Plan, and identifies the section in which the strategy is discussed.

Table 1-3. Results for Strategies Related to Electricity

Strategy or Measure	Advancement to Next Stage of Energy Plan Recommended	Subsection
Diesel Efficiencies		
Switchgear Improvements	Yes	2.3.1
Real-Time Economic Dispatch		2.3.1.2
Microprocessor-Based Engine Controls	Yes	2.3.1.3
Reduce System VAr Requirements		2.3.2.1
Life-Cycle Cost Analysis of Transformers		2.3.2.2
Life-Cycle Cost Analysis of Conductors		2.3.2.3
System Voltage Upgrades		2.3.2.4
Microprocessor-Based Protective Relays		2.3.2.5
Fuel Price Strategies		
Competition Among Suppliers		3.3.1
Purchase Consolidation		3.3.2
Enhanced Understanding of Markets		3.3.3
Replace Diesel No. 1		3.3.4
Alternative Delivery Methods		3.3.5
End-Use Conservation		
Lighting	Yes	4.3
Water Heaters	Yes	4.3.2
Other Appliances	Yes	4.3.3
Alternative Technologies		
Natural Gas / Coal Bed Methane		5.3.1
Energy Storage Systems		5.3.2
Fuel Cells		5.3.3
Geothermal Energy		5.3.4
Hydroelectric Power		5.3.5
Interties [a]		5.3.6
Microturbines		5.3.7
Small Coal Power Plants		5.3.8
Biomass [b]		5.3.9
Solar Energy		5.3.10
Tidal Energy		5.3.11
Wind Energy	Yes	5.3.12
Other Strategies (Not Analyzed)		5.3.13
Reliability		
Microprocessor-Based Protective Relays	Yes	6.3.1
Reclosers with Microprocessor-Based Controls		6.3.2

[a] Improvements in single wire ground return and direct current technologies over the past 5 years suggest that a review and update of the suitability, applicability, and cost of these technologies should be conducted as part of the next stage of the Rural Energy Plan. However, they are not recommended as strategies to be pursued in the next stage.

[b] See also discussion on potential of biomass to reduce the cost of space heating (Section 7).

Table 1-4. Results for Strategies Related to the Heating Sector and Tank Farm Construction

Strategy or Measure	Advancement to Next Stage of Energy Plan Recommended	Subsection
Space and Water Heating		
Insulation and Weatherization	Yes	7.3.1.1
Heater Upgrades	Yes	7.3.1.2
Waste Heat Recovery Systems	Yes	7.3.2
Biomass		7.3.3
Hot Water Tanks as Heating Devices		7.3.4.1
Conversion of Electric Water Heaters	Yes	7.3.4.2
Water Conservation Devices	Yes	7.3.4.3
Planning		7.3.4.4
Tank Farm Construction		
Force Account Construction		8.3.1
Conventional Competitive Bid Process [a]		8.3.2
Request Design Build Proposals from Private Firms [a]		8.3.3
Request Proposals from Private Firms to Build or Upgrade Group of Facilities		8.3.4
Request Proposals from Private Firms to Design, Build, Own, and Operate Facilities [a]		8.3.5
Existing Facility Owners Manage, Design, and Construct Their Own Upgrades and/or Replacements		8.3.6
Tank Farm Financing – Issues Addressed		
Local Contributions to Tank Farm Development		9.4.1
Fuel Cost Impact of Private Investment		9.4.2

[a] Strategies warrant field testing. Additional analysis on potential benefits is not needed.

Electricity: Strategies to Reduce Cost

2 Diesel Efficiencies and Other Equipment Upgrades to Conventional Power Plants and Distribution Systems

Summary

This section focuses on diesel efficiencies and upgrades to plants and systems that could be implemented to reduce the cost of electricity in rural Alaska. This preliminary analysis indicated that:

- Additional study is warranted for automated switchgear based on the potential of this strategy to reduce the cost of electricity by more than $0.01 per kWh to a large number of residents in rural Alaska.
- Other types of switchgear improvement could be considered by individual utilities.
- Additional research is needed for microprocessor-based engine controls and protective relay systems.

2.1 Introduction

This section describes existing conditions related to the efficiency of diesel-generating units and electric distribution systems in rural Alaska. Issues discussed include the size and condition of generating equipment, the types of switchgear used, and fuel efficiency in the production of electricity. This section also provides an analysis of specific measures to reduce the cost of electricity in rural Alaska, through improvements to generating equipment or the distribution system. Detailed analyses and value estimates are provided for the following measures:

- Improved switchgear, including switchgear automation upgrades, the addition of real-time economic dispatch (RTED), microprocessor-based engine controls, and microprocessor-based protective relays
- Reducing system reactive power requirements
- Life-cycle cost analysis for transformers
- Installation of microprocessor-based protective relay systems

Sufficient data were not available to prepare a detailed analysis of microprocessor-based engine controls. Still, the potential benefits of these controls are discussed (Subsection 2.3) along with the other measures considered. This section ends with conclusions and recommendations for further study as part of the Rural Energy Plan.

Table 2-1 summarizes relevant economic assumptions used in this section.

Table 2-1. Assumptions and Values

Item	Source or Rationale
The cost of diesel fuel is $1.00 per gallon.	This cost figure is close to the average for 1998 and 1999 in many communities and is a convenient reference number. It was chosen at the start of the analysis (before the increase in fuel costs of fall and winter 2000). Sensitivity analyses are provided in certain cases, with the effects shown for higher fuel costs.
No escalation in the real cost of fuel. (The price of fuel is assumed to increase at the rate of inflation.)	Long-term forecasts of oil prices have been shown to be highly speculative and AIDEA does not base investment decisions on projections of long term increases in the real price of oil.
The real discount rate is 3 percent	Future costs and benefits are discounted at a rate of 3 percent to account for the time value of money.

2.2 Existing Conditions

The electrification of small rural Alaskan communities began in the mid-1960s with the formation of AVEC, a utility that now serves approximately 50 rural Alaska communities. This process of providing communities with centralized power accelerated in the 1970s and 1980s as State of Alaska revenues grew following completion of the Trans Alaska Pipeline. Today, approximately 198 rural communities have centralized power, 187 of which participate in the state's PCE Program (Regulatory Commission of Alaska, 2000.)

The early power plants in rural Alaska were very basic, comprising two diesel generator sets and a single manual transfer switch. Many powerhouses were of "stick" construction with "post-and-pad" foundation and wood floors. During the intervening years, the generator sets have been overhauled and replaced. In many areas, controls have been upgraded, waste heat recovery systems have been added, and electrical distribution systems have been upgraded. In some instances, complete new power plants have been installed.

In addition to the hardware replacements expected over time, much of the impetus for power plant improvements has been increasing annual electrical consumption per household, as residents have become accustomed to the benefits of reliable electrical power and the related benefits and conveniences of electrical appliances. Overall community electrical consumption has also been affected by the construction of government-sponsored housing.

Diesel Generation in Place

Table 2-2 provides information on the overall condition of 44 Alaska powerhouses and diesel generator sets as surveyed by Precision Power for the AEA Circuit Rider program. Since the Circuit Rider program focuses on smaller utilities with lower-than-average operating funds and technical resources, the facilities in this sample are expected to be in below-average condition relative to utilities in rural Alaska overall. The table shows the percent of facilities rated "poor," "fair," "good," and "excellent." In addition, the table shows the percent of generator sets at various levels of running hours (hours elapsed in service).

Table 2-2. Overall Condition of Alaska Powerhouses and Diesel Generator Sets

Powerhouses		Generator Sets			
Condition		Condition		Running Hours [a]	
Rating	Percent of Facilities	Rating	Percent of Facilities	No. of Hours	Percent of Facilities
Poor	23	Poor	24	More than 30,000	22
Fair	9	NA	NA	More than 20,000	12
Good	64	Good	46	More than 10,000	27
Excellent	4	Excellent	30	Less than 10,000	39

Source: Precision Power survey work for Year 2000 Circuit Rider and Emergency Response Program (for AIDEA)
[a] Running hours data were available for 113 of 130 engines surveyed.
NA = Not applicable: no generator sets were given a rating of "fair."

No data are available on whether the engines have been overhauled within the engine's running hours. Precision Power found that very few engines in rural utilities are overhauled. In most cases, the cost to purchase and install a new replacement engine equals the combined cost of labor, parts, and travel to overhaul an engine onsite.

Several recurring problems have been identified among the powerhouses rated as being in poor condition:

- Leaking coolant, oil, and exhaust systems
- Exposed electric panels and wires
- Waste oil, empty containers, and oily rags in building
- Soot on walls
- Leaking roofs

Of the 130 generator sets inspected, 4 were rated inoperable. In addition, 42 percent of the utilities needed to repair one or more engines.

One surveyed utility generates electricity with a combination of hydroelectric turbines and diesel generators. All other utilities operate diesel-only power plants. Of these utilities, all but four have a minimum of three diesel generator sets in the power plant. Two utilities purchase power from the local school during winter and generate their own power during summer.

1,200-RPM and 1,800-RPM Engines

Approximately 23 percent of the surveyed utilities have one or more 1,200-rpm engines. Some utilities have purchased 1,200-rpm generator sets instead of conventional 1,800-rpm units, with the expectation of some fuel savings and a longer operating life.

A difference in estimated life normally would be a factor in a life-cycle cost analysis, and the longer expected life of the 1,200-rpm engine could make the 1,200-rpm generator set less expensive to own and operate over time than an 1,800-rpm set. However, in Alaska's small rural utilities, the average life of an engine is around 20,000 to 30,000 hours, regardless of operational rpm, mainly because of maintenance deficiencies.

On average, 1,200-rpm generator sets cost approximately 30 to 50 percent more than similarly sized 1,800-rpm units, and actual differences in 1,200- and 1,800-rpm generator sets may not justify the extra costs. Technological advancements in metallurgy, improved engine design, and better engine lubricants have narrowed the difference in mean time to overhaul for the 1,200- and 1,800-rpm units. In addition, Precision Power has found that, due to the increasingly competitive market in the size range of engines used in rural Alaska (30-kilowatt [kW] to 300-kW), the 1,800-rpm configuration provides more installed kW per dollar spent than the 1,200 rpm engines can provide.

Switchgear

There are different methods used to switch diesel generator sets online and offline. Rural Alaska power plants use a wide range of controls, from the most basic manual systems to highly sophisticated, automated systems. Precision Power estimates that 81 percent of the utilities in rural Alaska currently have switchgear capable of synchronizing and paralleling more than one generator set at a time. Table 2-3 provides a summary of switchgear types found in utilities in rural Alaska.

Table 2-3. Types of Switchgear Used in Rural Alaska Utilities

Switchgear Type	Functionality
Interruptible Power Transfer	
Manual Circuit Breakers	Circuit breaker - open or closed.
Manual Transfer Switches	Lever or switch allows only one generator set to be online at a time.
Uninterruptible Power Transfer	
Manual Synchronizing	Two generator sets can be paralleled to transfer from one to the other or to operate more than one at a time. Successful transfer is dependent on manually synchronizing generators prior to transfer.
Semi-Automatic Synchronizing	Same as manual synchronizing, except that the controls prevent paralleling until generator sets are synchronized.
Fully Automatic Synchronizing	Logic within the controls monitors the demand and determines when one or more generator sets will start up and go online or offline.

Electronic Governors and Electronic Injection

Mechanical governors can be used to parallel two generator sets for switching purposes, but some models allow the generators to lose synchronization and the generators must be manually adjusted periodically.

Electronic governors provide more stability with faster response to load changes, thereby resulting in some fuel savings. Electronic governors make it possible to parallel and keep two generator sets synchronized for extended periods.

Almost all of the newer diesel engines in rural Alaska have electronic governors—most prime power diesel generators manufactured today are used in conjunction with synchronizing switchgear and have sensitive electrical loads that require tightly regulated power.

Electronic governors already are widely used by Alaska's rural utilities. Precision Power found that 42 of the 44 power plants inspected had electronic governors. Precision Power also anticipates that electronic governors and controls soon will displace the remaining mechanical governors in use. (Precision Power estimates that not more than 5 percent fuel savings is obtained with electronic governors, and this savings is already reflected in the PCE program statistics due to the high percentage of utilities using electronic governors.)

Fuel Consumption

Fuel consumption (the amount of fuel needed to generate and deliver 1 kWh of electricity) depends on engine size and efficiency, line losses, and other factors. The state standard on generating efficiency and line loss according to Title 3 of the *Alaska Administrative Code* ranges from 8 to 12 kWh per gallon for all electricity sold (3 AAC 52.620).

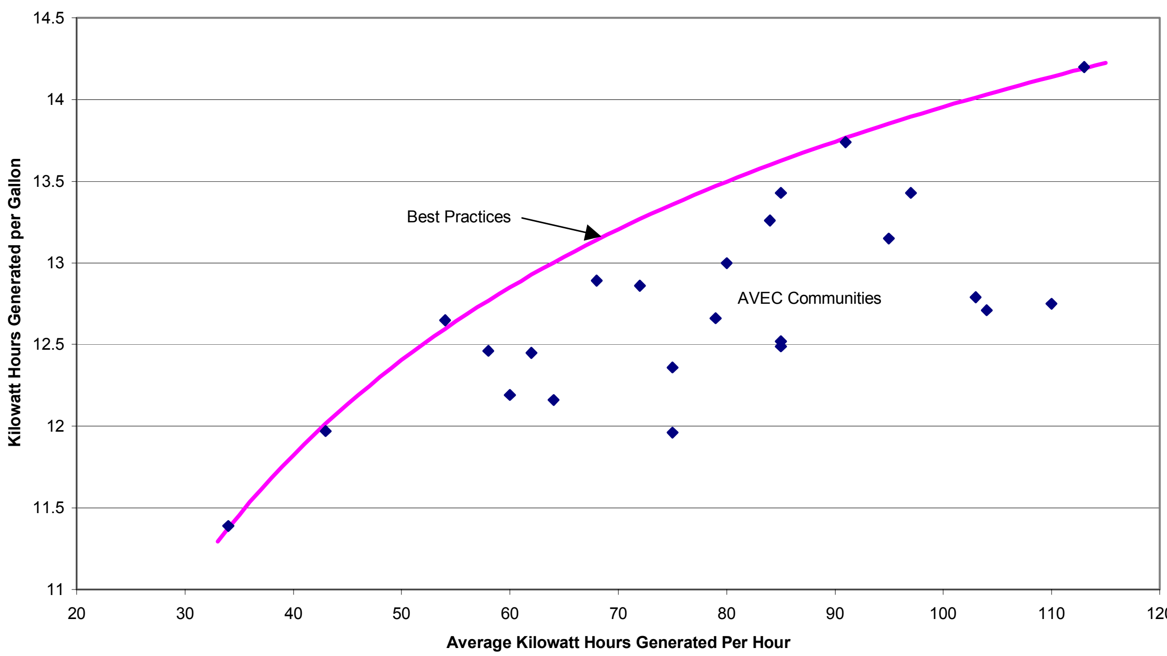
Precision Power estimates that actual line loss in rural Alaska may vary from 5 to 20 percent, but the expected loss is in the range of 7 to 10 percent. (Data are readily available on kWh sales by rural utilities. However, data are not readily available on kWh generation, making it difficult to accurately determine line loss.)

Figure 2-1 shows fuel efficiency for AVEC utilities, with the number of kWh generated per gallon of fuel at utilities of different sizes. Table 2-4 shows the fuel efficiency standard for utilities of different sizes according to 3 AAC 52.620, with utilities sized by kWh sales. The table also shows the percent of utilities in each size category that met or exceeded the standard in 1998.

In addition to engine size, fuel efficiencies depend on the manner in which the power plant is operated (including whether or not the power plant has the ability to switch generator sets without interruption and to run one or more generator sets at a time) and how well generating equipment is matched to system load. In general, efficiency is inversely proportional to the extent to which generator sets are oversized for load. The more closely matched the generator set is to the load requirement, the greater the fuel savings.

Using larger generator sets to satisfy relatively small loads can result in higher fuel consumption if the engine is operated at 50 percent of rated capacity or lower. Using multiple small generator sets in parallel to meet high demand (as opposed to running a single, larger generator set) can also result in poor fuel efficiency and increased engine wear.

Figure 2-1. Fuel Efficiency for Alaska Village Electric Cooperative Utilities



Source: Dames & Moore, 1998.

Table 2-4. Title 3 AAC 52.620 Fuel Efficiency Standards and Percent of PCE Utilities Meeting Standard, 1998

Indicator	Value by Utility Size Category				
Utility Size Category (Number of kWh Sold)	**Less Than 100,000**	**100,000 - 499,999**	**500,000 - 999,999**	**1,000,000 - 9,999,999**	**10,000,000 or More**
PCE Standard [a] (No. of kWh Sold per Gallon)	8	9	10	11	12
Utilities Meeting or Exceeding Standard (Percent)	100	72.7	79.1	84.6	100

[a] PCE standard effective October 1, 1993

2.2.1 Village Cases

The following text is a summary of observations and projects completed by EPS and Neubauer Engineering and Technical Services (EPS/NETS) for specific villages in rural Alaska.

2.2.1.1 Tlingit-Haida Regional Electric Authority—Kake Power Plant

In 1998-1999, EPS/NETS installed and programmed a programmable logic control (PLC) based plant control and monitoring system for Tlingit-Haida Regional Electrical Authority (THREA) in Kake. The installation included controls and monitoring for three units (560- to 1,000-kW). The Kake system was designed and installed to provide not only unit commitment capabilities for the plant, but remote monitoring and alarming functions. The system is configured to auto-dial THREA operations personnel for alarm conditions at the plant, so that problems can be corrected before a shutdown is required. Additionally, THREA personnel can dial the plant to remotely monitor real-time and accumulated metering functions.

The original impetus for installing the system was to match generation to load more readily. In addition to addressing the classic unit commitment issue, the system was built to allow the local cannery to send a request to the plant for a large motor start, and the automatic generation control system would determine whether another unit was required to support the cannery load. The appropriate generation adjustments were made without operator intervention, and instructions were sent to the cannery, allowing the large motor to start when needed.

2.2.1.2 Cordova Electric Cooperative—Humpback Creek Power Plant

In 1999-2000 EPS designed, and is in the process of installing and commissioning, a PLC-based plant control and monitoring system for Cordova Electric Cooperative (CEC). The system performs the functional equivalent of unit commitment capabilities for the hydroelectric plant.

The Humpback Creek Power Plant (HBC) is a run-of-the-river plant that operates at maximum capacity, given the flow available from the creek. The control system controls the power output from each of three individual units and automatically puts units online or offline, based on the available water in the flume. The HBC installation includes controls and monitoring for three units (250- to 500-kW). The system was designed and installed to provide not only unit commitment capabilities for the plant, but also SCADA (system control and data acquisition) functions and governing functions for the machines.

The original impetus for installing the system was to match generation to available water resources more readily, and thus maximize generation of hydroelectric power. In addition to the hydro unit commitment, the system was built to allow interface to CEC's developing SCADA system.

2.3 Analysis of Strategies

The subsections that follow address issues related to the cost of electricity produced by diesel generator sets in rural Alaska. Issues are divided into two main categories: generating equipment and distribution systems. Strategies designed to improve efficiencies in generation are included in the first category and strategies designed to reduce line losses and other system distribution system losses are included in the second category.

Net present value calculations were conducted on all proposed strategies to evaluate their cost-effectiveness for a model village. Net present value is defined as the potential savings that may result from implementing the strategy, minus the cost of implementing the strategy. A positive net present value is an indicator that the strategy should be considered an economically viable option.

Assumptions

The financial variables used in the analyses that follow are identified in Table 2-4. These variables include the discount rate (cost of capital) and planning period. The fuel usage for the model village assumed in the analysis is shown in Table 2-5. This model represents a relatively small but typical PCE community.[5] This model may not be representative for larger communities in part because larger communities can experience economies of scale. Larger communities may experience larger benefits than suggested by this model community.

Table 2-5. Financial Variables

Variable	Description	Value
WACC	Weighted Average Cost of Capital (Real)	3 Percent
Useful Life	Useful Equipment Life	30 Years
Salvage Value	No salvage value is assumed at the end of the useful life.	$0

Table 2-6. Model Village Fuel Usage and Cost

Item	Budget at Different Average Fuel Costs per Gallon	
	$1.00	**$1.50**
Annual Fuel Usage (No. of Gallons)	60,000	60,000
Total Annual Fuel Budget	**$60,000**	**$90,000**

2.3.1 Generating Equipment and Related System Controls

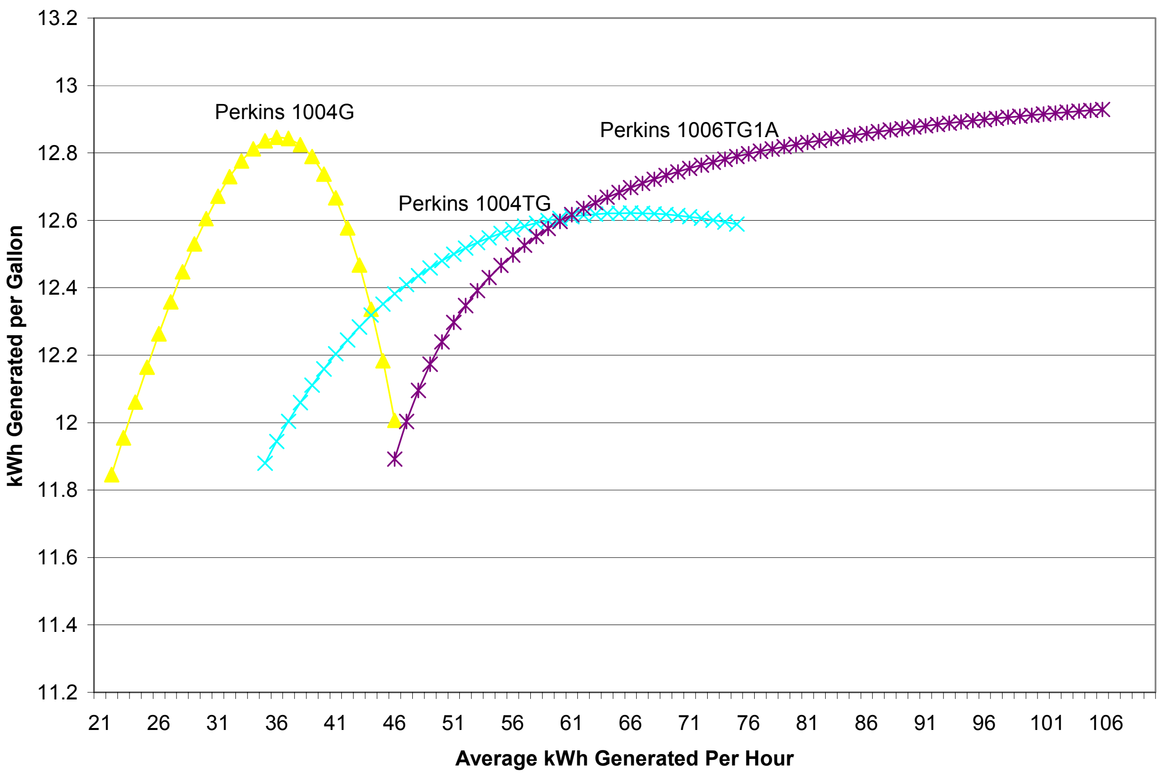
A major issue related to the cost of electricity in rural Alaska is how well the generating equipment in use matches the demand. Generator units tend to be less efficient (in terms of gallons of fuel used to generate a certain amount of electricity) if the demand is too low or too high for the size of the unit. Figure 2-2 shows fuel efficiency curves for three Perkins generator units and illustrates how fuel efficiency changes, depending on the amount of electricity produced by a generator and the type of generator used. In each of the three cases shown in the figure, the generator unit has a peak level of efficiency in terms of the number of kWh generated per gallon of fuel. Efficiency can be very low if the generator is required to produce electricity at a rate that is higher or lower than its optimal rate. New controls described in this subsection, such as microprocessor-based engine controls, offer the potential to improve the efficiency of generator units over a broader range of output.

Utilities that have multiple generator sets must decide which generators to use at any given moment to meet demand as efficiently as possible. This topic includes operations and maintenance (O&M) issues that will be addressed in the companion report being prepared by ISER, but also switchgear and other engine controls. For example, new automated switchgear with RTED capabilities can determine

[5] This model community would be near the median for communities included in the PCE database if the six largest communities were not included.

automatically which generators should be operating at a given point in time (to meet demand at the lowest cost) and automatically turn on those generators.

Figure 2-2. Efficiency Curves for Selected Generator Units from Perkins



Source: Dames & Moore, 1998.

Improved Switchgear

The following discussion examines reductions in the cost per kWh of electricity generated that could potentially be realized with upgrades to generation switchgear. Other benefits of switchgear improvements, such as improved system reliability, are discussed in Section 6.[6]

The general topic of switchgear improvements is divided into subsections on switchgear automation upgrades, RTED, and microprocessor-based protective relays. Separate analyses and conclusions regarding future study are provided for each type or component of switchgear improvement. Microprocessor-based engine controls are mentioned, but sufficient data were not available to conduct a thorough analysis.

The analysis of switchgear improvements begins with installation of automated switchgear. The potential benefits of other switchgear improvements, such as the installation of RTED capabilities and full SCADA systems, are considered as possible additions to a generating system with automated switchgear. More generally, diesel engine and electric generator switchgear includes circuit breakers, transfer switches, and synchronizing controls.

[6] In many cases, utilities install RTED capabilities at the same time as automated switchgear. In this report, these strategies are viewed as independent but linked opportunities.

Improving or upgrading these controls offers a variety of possible benefits, including improved fuel efficiency and reduced maintenance on equipment. When capital improvements are made to upgrade and modernize switchgear, many benefits can be realized for an incremental cost that could not otherwise be justified. For example, if a utility has made the decision to install automated switchgear, it could then consider the incremental costs and benefits associated with more sophisticated switchgear. (The analysis of RTED capabilities is something that a utility might consider beyond automated switchgear controls. The utility would not compare and contrast automated switchgear controls with RTED capabilities.)

Three aspects of plant automation that can have benefits in many PCE communities are:

1. Unit commitment can be controlled and optimized to match online generation to load requirements more efficiently.
2. Remote monitoring, control, and alarming capabilities can be integrated into the system to more efficiently control the flow of information to appropriate personnel, making plant operation safer and more reliable.
3. Specific local system needs can be accommodated with a flexible, open-control system architecture.

EPS, Precision Power, and others estimate that the installation of automated switchgear could reduce fuel consumption by 5 to 20 percent in rural utilities.[7] This level of savings would significantly reduce the cost of electricity in rural Alaska (for example, a 10 percent reduction in fuel costs would lower the cost per kWh by more than $0.01). In addition, Precision Power and EPS believe that a large number of rural utilities (5 to 10 or more) could benefit from automated switchgear. Additional benefits could be realized if RTED capabilities are considered at the time when automated switchgear is installed. RTED capabilities do not offer the same potential as automated switchgear, but could further enhance system controls and improve overall system performance.

2.3.1.1 Switchgear Automation Upgrade

Overview. One way to increase efficiency in electricity generation is to upgrade existing switchgear with an automated load share and demand system. The advantages of automated switchgear include more accurate control of generator sets and reduced labor expenses. Utilities that do not have automated switchgear must rely on a plant operator to monitor system load and to determine which generator sets should be operating at any given time to optimize system performance.

Installing automated switchgear appears to have the potential to significantly reduce the cost of electricity to a large number of residents of rural Alaska. As a result, this strategy is recommended for further review.

Analysis. The tables in this subsection depict the economic analysis for a generation switchgear automation upgrade in a model village in rural Alaska. A notable deviation from the economic model in Table 2-5 is in the assumed useful life of the installation. While the proposed technology would likely remain viable for 30 years, experience in SCADA and plant control system installations indicates that equipment often is changed more frequently to upgrade to more recent technology. For this reason, this analysis assumes a more conservative useful life of 20 years.

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[7] EPS and Alaska Power and Telephone (AP&T) both estimate that savings would be 5 to 10 percent. Precision Power estimates that savings would be 20 percent. Tanana Power Company, Inc., reported in a comment letter to the draft report that it had realized fuel savings of 13 percent with automated switchgear.

The analysis was conducted for two different installation costs for a three-machine diesel plant to bracket the possible range of costs for a small installation. The installation cost would be between $50,000 and $70,000. Two primary factors contribute to the variation in cost:

- The level of monitoring and alarming included
- The amount of force account labor used for the plant-to-control system wiring

Table 2-7 is a breakdown of components included in the total costs of $50,000 (Option 1) and $70,000 (Option 2). Table 2-8 shows the net present value of installing automated switchgear at these two price levels. The cases considered here for a small plant installation should be the worst economic case. If a larger plant is considered, the net present value calculations should yield better results, because system installation costs will not increase linearly with the size of the installation.

Table 2-7. Generator Automation Switchgear Upgrade for a Three-Machine Plant

Item	Installed Cost ($)	
	Option 1	Option 2
PLC/Communications Hardware	23,000	29,000
PLC/ Communications Software	14,000	20,000
Plant Wiring	4,000	8,000
Transducer Installation	3,000	5,000
Setup and Commissioning	6,000	8,000
Total	**50,000**	**70,000**

Table 2-8. Estimated Fuel Savings and Net Present Value of Generation Switchgear Automation Upgrade

Variable	Net Present Value at Different Average Fuel Costs ($)	
	$1.00 per Gallon	$1.50 per Gallon
Option 1		
Annual Fuel Savings [a]	89,265	133,900
Installation Cost	50,000	50,000
Net Present Value [b]	39,265	108,900
Option 2		
Annual Fuel Savings [a]	89,265	133,900
Installation Cost	70,000	70,000
Net Present Value of Installation [b]	19,265	33,900

Note: The assumed annual fuel usage for the model village is 60,000 gallons.
[a] Fuel savings with automated switchgear are assumed to be 10 percent (based on conversations with Precision Power).
[b] Net present value calculations are based on a useful or expected switchgear life of 20 years and other financial variables shown in Table 2-4. The planning horizon for net present value calculations is 20 years.

Conclusions. The positive net present value calculations indicate that the generator automation switchgear upgrade should be considered a viable option and its application should be considered for PCE villages. Precision Power estimates that the installation of automated switchgear could reduce fuel consumption by 20 percent in rural utilities. This level of savings would significantly reduce the cost of electricity in rural Alaska (a 20 percent reduction in fuel costs would lower the cost per kWh by more than $0.01). This strategy is recommended for further analysis in the Rural Energy Plan.[8]

2.3.1.2 Real-Time Economic Dispatch

Overview. Once a unit is online, and, if multiple units are online to meet the load, RTED can be used to optimize the overall fuel usage of the plant. For machine load acceptance, RTED monitors the operating points of the online units; decides, based on the incremental cost of the “next kW,” on which machine the next kW is to be loaded; and adjusts the setpoint of that machine accordingly. If system load is decreasing, RTED takes the next kW off the machine that has the incrementally most expensive kW, at its current operating point.

Historically, RTED has been implemented in a number of configurations:

- For a multi-plant system, as in urban utilities, the RTED function is performed at the master control center. The unit setpoints for multiple units, located at multiple plants, are then communicated to the plants, where the actual control is performed on the machine setpoints.
- For single-plant installations, as is typical for PCE utilities, the RTED function can be performed onsite at the power plant. For a plant with an open-architecture controller, based on an industry standard PLC or functional equivalent (as described in Subsection 2.2.1), the RTED function can be added easily as a software module in the control system.

RTED capabilities do not offer the same potential as automated switchgear, but could further enhance system controls and improve overall system performance. The addition of RTED capabilities, when viewed alone, does not have the potential to significantly reduce the cost of electricity to a large number of residents in rural Alaska. However, RTED capabilities can be added to system controls at relatively low cost and can add to the overall performance of generating equipment. RTED is not recommended for further review as a separate strategy, but is recommended for consideration as part of the overall switchgear improvement package.

Analysis. If the normal operation of the power plant is with multiple units online, EPS estimates that fuel costs might be lowered by as much as an additional 5 percent by adding RTED. RTED savings are realized only while more than one unit is online.

Adding RTED to the generation switchgear automation upgrade discussed in Subsection 2.3.1.1 would cost an estimated $24,000 for a three-machine plant. This cost is based on preliminary estimation work that was done by EPS to perform RTED (using a PLC as a controller) for a similar installation, as described in Subsection 2.2.1. The industry standard expectation for fuel savings from using RTED is generally 5 percent. Based on this estimate, the economic analysis was conducted at fuel savings of 3, 4, and 5 percent.

The assumed fuel usage for the model village is the same as discussed in Table 6-3 and used for the generation switchgear automation upgrade. Table 2-9 shows the projected fuel savings for the model village. Table 2-9 also shows the net present value of installing RTED capabilities. The estimates incorporate three different fuel savings assumptions (3, 4, and 5 percent), the financial variables identified in Table 2-5, and the more conservative useful life of 20 years.

[8] As discussed in the next subsection, additional benefits could be realized if RTED capabilities are considered at the time when automated switchgear is installed.

Table 2-9. Value of Adding RTED to Existing Generator Control System

Indicator	Net Present Value ($) of Installing RTED Capabilities at Different Fuel Savings Levels (Percent)					
Percent Fuel Savings	**3 Percent**		**4 Percent**		**5 Percent**	
Average Fuel Costs ($ per Gallon)	**$1.00**	**$1.50**	**$1.00**	**$1.50**	**$1.00**	**$1.50**
Fuel Savings	1,800	2,700	2,400	3,600	3,000	4,500
Net Present Value of Savings [a]	**2,780**	**16,170**	**11,710**	**29,560**	**20,630**	**66,950**

Note: The assumed annual fuel usage for the model village is 60,000 gallons.
[a] Net present value calculations are based on a useful or expected switchgear life of 20 years and other financial variables shown in Table 2-3. The planning horizon for net present value calculations is 20 years.

Conclusions. The positive net present value calculations indicate that the addition of RTED to a generator automation switchgear upgrade should be considered a viable option, and its application should be considered for PCE villages where multiple machines are online simultaneously. However, this strategy is not recommended for further study in the Rural Energy Plan as a standalone strategy. It appears that the potential of RTED controls would be maximized if the installation of such controls is considered at the same time as automated switchgear.

2.3.1.3 Microprocessor-Based Engine Controls

Overview. Electronic-microprocessor-based engine controls offer improvements over electronic governors and controls. In particular, the new microprocessor-based engine controls eliminate many of the mechanic linkages on diesel engines, including throttle cables. These controls are designed to reduce emissions, improve cold/hot starting, and provide selectable engine speeds.

AVEC and Precision Power report that electronic-microprocessor-based engine controls have significant potential to reduce the cost of electricity in rural Alaska. Data have been requested from engine manufacturers to properly analyze the potential of these controls. This analysis should be included in the next phase of the Rural Energy Plan.

Analysis. Precision Power estimates that microprocessor-based engine controls enable certain engines to produce 10 percent more horsepower for a limited period. In some instances, this increase could permit the selection of a smaller generator set that can still meet intermittent peak demands.

AVEC has suggested that microprocessor-based engine controls have the potential to significantly reduce the cost of electricity in rural Alaska. Unfortunately, information requested from various diesel engine manufacturers to properly analyze the benefits did not arrive before this study was completed.

Conclusions. Despite the lack of data available at this time, the potential benefits estimated by Precision Power and AVEC are such that this strategy should be reviewed in more detail. Microprocessor-based engine controls are recommended for further study. A complete analysis can be conducted when data are provided by engine manufacturers. The complete analysis should include an assessment of existing efficiency levels for electricity generation in rural Alaska, as well as certain issues related to O&M, generator size, and generator condition.

2.3.2 Distribution System Improvements

Distribution system losses represent the difference in the amount of electricity generated and the amount of electricity consumed. For example, a utility may generate 100 kWh, but sell only 90 kWh. The remaining 10 kWh could be lost due to resistance in the distribution system (including distribution lines, transformers, and other elements) or due to reporting and monitoring errors.

Distribution system improvements are generally considered modifications that improve the quality of service, as in the case of installing improved protection and sectionalizing. However, improvements to the distribution system tend to increase overall efficiency of generation and delivery of energy by reducing system losses, thus increasing overall system efficiency (defined as the amount of energy productively consumed divided by the overall energy generated). Reducing losses in a system, therefore, is a strategy for improving the overall operating efficiency of the power system.

Distribution system losses, including line losses, in rural Alaska are difficult to analyze due to the quality of available data on amounts of electricity generated and sold. PCE data maintained for unregulated communities by the Regulatory Commission of Alaska include kWh sales and kWh generated, by community. However, for some communities in the PCE database, the data show adjusted sales figures exceeding adjusted generating figures (where generating is supposed to include any electricity purchased from other sources), indicating that system losses are negative. For some communities, PCE data show system losses exceeding 75 percent of the power generated.

The PCE data on kWh generation and sales cover 1995 to 1997 for selected communities (a total of 225 data points, covering 76 unregulated communities or utilities over a 3-year period). Based on these data, the average level of system loss is 13 percent and the median level of system loss is 12 percent. The average falls to 12 percent if the data points are removed where system losses are zero or below, or 35 percent or higher. (These data points could be removed based on the assumption that they reflect monitoring or reporting errors.)[9]

In comparison, Chugach Electric Corporation in Anchorage has reported distribution system losses of 6 to 7 percent in the recent past.[10] Based on this comparison, a decrease in system losses in rural Alaska from 12 percent to 7 percent appears to be theoretically possible. If fuel costs were $0.10 per kWh, this 5 percent increase in generating and distribution efficiency (from 7 percent to 12 percent) would lower the cost of electricity by less than $0.01 per kWh ($0.10 per kWh multiplied by 0.05 equals $0.005 per kWh). The relevant question is whether specific measures designed to reduce system losses could significantly reduce the cost of electricity in enough communities—specifically, those with high losses—to make the strategies worthwhile. In addition, conclusions about the theoretical potential of reduced system losses should be based on data from a broader set of communities.

In general, distribution system losses can be reduced in three general areas: installing transformers with optimal loss characteristics, installing conductors with optimal loss characteristics, and increasing the operating voltage of low-voltage distribution systems. This section includes three strategies designed to reduce distribution system loss, including transformer purchases, conductor evaluations, and system voltage upgrades, and two strategies to improve distribution efficiency: use of microprocessor relays and installation of system capacitors. None of the strategies is recommended for research beyond this screening analysis. However, the strategies could be implemented by rural utilities as part of an effort to improve efficiency and reduce costs.

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[9] A better approach would be to investigate utilities that have very small or very large system losses to determine the actual causes.

[10] Estimate from previous communications between EPS and Chugach Electric Association.

2.3.2.1 Reduce System VAr Requirements

Overview. A generator produces two independent types of power: real power, or watts, and reactive power, or VArs (volt-amperes reactive). Real power performs work: it produces heat, causes motors to turn, produces light, and runs pumps. Reactive power is consumed by inductive loads (the predominant reactive loads in a power system) and generated by machines, or shunt capacitors. Both types of power must be produced in the system, but often (due to tariff or utility practices) only the real component of power produces revenue.

EPS estimates that the larger PCE utilities could benefit from power factor correction, either by modifying transformer tap position settings, or by installing system capacitors. In many village systems, especially those with cannery or cold storage loads, the application of power factor correction can defer or eliminate the need to start a peaking unit. If the generator sets are volt-ampere (VA) limited, power factor correction can reduce the VA output, allowing the units to produce more real power. In addition, application of system capacitors at the end of a distribution line allows the operating utility to reduce system voltage (within acceptable limits), effectively reducing system load.

Reducing the reactive power requirements of generating units (expressed as VAr requirements) in rural Alaska utilities is not recommended for further review. No data exist that show this strategy to have the potential to significantly reduce the cost of power for a large number of residents in rural Alaska, but it may be a strategy that certain utilities should consider.

Analysis. A physical relationship exists between real and reactive power:

$$\text{Apparent power}^2 = \text{real power}^2 + \text{reactive power}^2$$

Apparent power is measured in VA.

Machines characteristically have independent ratings for each type of power, due to different physical constraints of the machine. Wattage generally is limited by the ability of the stator windings to dissipate heat. VArs are constrained either by limitations in the field winding or by heating effects in the stator end iron. Both of these limitations can be less than the VA rating of the machine, which is specified at a particular power factor.

The machine can produce its rated real power output as long as the number of VArs that must be produced is not excessive. If the machine is called on to produce a significant number of VArs in addition to the real power requirement, the production of one of these types of power will be limited. At this time, additional generation would be required to deliver the required power.

If the number of VArs required could be reduced, additional machines may not need to be started to meet the VA demand. Reduction of the number of VArs that the machine must produce can be accomplished in two ways: the net VAr demand of the system can be reduced, or passive VAr generators (capacitors) can be placed on the system.

System VAr requirements can be modified in a number of ways. Classically, capacitors have been installed, either at the distribution voltage or at the secondary voltage. Two methods of controlling VAr flow in the system are modification of transformer tap settings, and switching loads to minimize VAr requirements.

For rural Alaska villages, the minimum size of capacitors available for application at primary voltages is too large. This limits the application of capacitors to secondary voltage.

To adequately analyze the costs and benefits of reducing system VAr requirements, an in-depth system study needs to be conducted, on an individual system basis. The strategy would not likely be generally applicable to the majority of PCE villages, but may be applicable for some of the larger villages. The data required to accurately conduct an evaluation include the following:

- System description, including conductor sizing and lengths
- Generation impedance data
- Power transformer impedance data
- Load data for individual large consumers (canneries, schools, and others), including VAr loadings
- Daily and seasonal load characteristics
- A typical generation dispatch corresponding with the above load characteristics
- Plant fuel cost
- If an interconnection exists between multiple plants, interconnection and load data with which to calculate transmission penalty factors

Conclusions. Installation of system capacitors may be an appropriate strategy for some systems where VA limiting of machines is observed due to high VAr loadings. When the machine is VA- or VAr-limited, it cannot produce any additional real power, even though the machine may be below its kW rating. In some cases, this situation will require the starting of an additional peaking machine. Some of these VAr-induced starts can be avoided by the installation of system, or power factor correction, capacitors. Community-specific data and engineering studies are needed to determine the value of this strategy.

No data exist that show this strategy to have the potential to significantly reduce the cost of power for a large number of residents in rural Alaska. Reducing VAr requirements may be a strategy that certain utilities should consider, but it is not recommended for further review in the Rural Energy Plan.

2.3.2.2 Life-Cycle Costing Evaluation of Transformer Purchases

Overview. Requesting that transformer manufacturers provide a life-cycle cost analysis of the transformers they offer is a strategy that PCE utilities could employ to ensure that they are purchasing the lowest-cost transformer. When a utility purchases a transformer, it must decide whether to purchase a lower-cost, higher-loss transformer or a higher-cost, lower-loss transformer. Utilities can have the analysis conducted for them by the transformer manufacturer (utilities can ask for a life-cycle cost of transformer alternatives by different manufacturers as part of the bid process. All that the utility needs to do is to supply the transformer manufacturer with data on fuel costs and system load.)

This strategy is not recommended for further study because it does not appear to have the potential to significantly reduce the cost of electricity in rural Alaska. However, it is a no-cost action that most utilities should consider.

Analysis. Many utilities with kWh costs much lower than typically found in rural Alaska purchase medium power and distribution transformers based on an evaluated cost, which often results in the purchase of a low impedance unit. This evaluated cost concept allows the utility to evaluate the life-cycle cost of the transformer, which is determined largely by the actual cost of losses produced by the transformers and the utility's cost of capital. Manufacturers typically conduct this analysis to optimize transformer design, based on the individual utility's cost structure and cost of capital. Utilities can request that the analysis be included by the manufacturer with any offer.

The economic evaluation for this strategy was conducted on a per-transformer basis. The transformer under consideration in this example is a single-phase, 15-kilovolt (kV), 25-kilovolt-ampere (kVA), 120/240-volt (V) transformer. Table 2-10 identifies the variables used in evaluating this strategy. The data used for losses and costs of transformers were derived from a recent bid analysis for transformers from an Alaska utility. The annual cost per kW of losses for the transformer was calculated by multiplying the cost of energy by the number of hours at the operating point/year. Deriving the annual cost of losses allows comparison of transformer designs.

Using the data shown in Table 2-10, the annual savings in losses by using a low-loss design over a nominal transformer design were calculated by multiplying the cost of losses by incremental losses (where incremental losses are the difference in losses between the low loss unit and the nominal design transformer). Given the financial variables shown in Table 2-5 and the strategy variables in Table 2-10, net present values of the installations are shown in Table 2-12.

Table 2-10. Variables Used in Transformer Life-Cycle Cost Purchase Evaluation

Item	Value
Assumed Fuel Cost	$1 or $2 per Gallon
Assumed Average Fuel Efficiency	10 kWh per Gallon
Variable O&M Costs	$ 0.01 per kWh
Low Loss Transformer Losses at No Load	0.22 Percent (55 Watts)
Low Loss Transformer Losses at Full Load	0.32 Percent (80 Watts)
Normal Loss Transformer Losses at No Load	0.44 Percent (110 Watts)
Normal Loss Transformer Losses at Full Load	0.85 Percent (213 Watts)
Incremental Cost for the Low Loss Transformer	$400
Percent Operating Life Near No Load	75 Percent
Percent Operating Life Near Full Load	25 Percent

Source: The data used for losses and costs of transformers were derived from a recent bid analysis for transformers from an Alaska utility.
Notes: The transformer under consideration is a single-phase, 15-kV, 25-kVA, 120/240-V transformer. Variable O&M costs are related to transformers and are not intended to include all O&M costs for diesel systems.

Table 2-11. Transformer Life-Cycle Cost Purchase Evaluation

Variable	Net Present Value at Different Average Fuel Costs ($)	
	$1.00 per Gallon	$1.50 per Gallon
Losses at Heavy Load	590	891
Losses at Light Load	736	1,110
Subtotal	1,326	2,001
Incremental Cost of Low Loss Transformer	400	400
Net Present Value	**926**	**1,602**

Note: The transformer under consideration is a single-phase, 15-kV, 25-kVA, 120/240-V transformer.

Conclusions. Transformer life-cycle cost purchase analysis could be applied widely in PCE utilities. This strategy requires only an estimation of the operating history of transformers and a change in purchasing procedures. The positive net present value calculations indicate that the transformer life-cycle cost purchase evaluation should be considered a viable option and its application should be considered for PCE villages. However, no data exist which show that this strategy would significantly reduce the cost of electricity in rural Alaska to a large number of residents. The number of transformers purchased each year is small for most rural utilities and the total reduction in distribution system losses might not be significant. Therefore, this strategy is not recommended for further study.

2.3.2.3 Life-Cycle Costing Evaluation of Conductor Purchases

Overview. Economic selection of conductors is analogous to economic selection of transformers, as discussed in Subsection 2.3.2.2.

Analysis. Larger urban utilities often select their cable and conductor sizes based on ultimate capacity (in amps) and a comparison of losses with smaller, less expensive conductors with the costs of upgrading to a larger conductor size, or different conductor type.

For logistical reasons, utilities tend to standardize on a small number of conductor sizes and types to minimize inventory items and the associated cost of logistics. For a rural system, typical overhead conductor sizes of #4, #2, 1/0, and 4/0 may be considered. While some system loadings require 336 and 397 aluminum, larger steel-reinforced conductors have more substantial equipment requirements for handling.

The distribution system designer must estimate an "average" loading point for various feeder sections being designed and assign a "life-cycle" cost to those loadings based on a given assumed conductor life. The net present value of this 20-year recurring cost would then be compared to the cost of upgrading to the next standard conductor size, and a conductor size would be selected. This procedure gives the designer economic considerations in conductor selection, rather than simply electrical constraints. For systems with high generation costs, heavily loaded conductors, the economics may dictate an upgrade to a larger conductor size.

It is important to limit the types and sizes of conductors that are available for consideration in the design and procurement process, to minimize the logistical difficulties and inventory carrying costs associated with keeping a large variety of conductors and associated connectors, splices, and terminations.

Conclusion. Data are not available to conduct a detailed analysis of this strategy. Such an analysis would need to be conducted for specific cases. However, the cost of implementing the strategy is minimal because it only requires the designer to consider life-cycle economics when choosing the utility's standard conductors.

Annual expenditures by rural utilities on conductors probably are not large enough to allow this strategy to have a significant impact on the cost of electricity. As a result, it is not recommended for further study in the Rural Energy Plan.

2.3.2.4 System Voltage Upgrades

Overview. Upgrading the distribution voltage for power systems can reduce losses by reducing the current flowing through the line. By reducing losses, the amount of energy generated can be reduced.

Analysis. Historically, many rural power systems were designed and installed to provide service to communities encompassing relatively small geographic areas. Initial capital construction investment can be lower for systems that operate at low voltage (typically 480 V) than for systems that serve larger areas. In larger communities and in villages that grew geographically, higher-voltage systems were installed initially or have been upgraded. In rural Alaska, these systems typically have been operated at 12 kV, allowing longer lines with acceptable end-of-line service voltages, and reducing system losses on those lines.

The State of Alaska has upgraded a number of low-voltage community systems to more conventional 12-kV systems. The primary impetus behind the upgrades performed to date has been code violation problems that exist on these older, low-voltage systems, rather than the economics of operating at lower voltage. Currently less than five PCE villages are operated as low-voltage systems. These systems are under consideration for upgrade, due to code compliance issues.

Conclusion. The State of Alaska could consider the economic benefits of low-voltage system upgrades as well as code violation issues. The economic benefits could be significant. However, because the number of villages with low-voltage systems is so small, this strategy is not recommended for further study in the Rural Energy Plan.

2.3.2.5 Installation of Microprocessor-Based Protective Relaying Systems

Overview. Installation of microprocessor-based relays can lower the cost of electricity by lowering maintenance and equipment costs associated with protective relay systems. Microprocessor-based relays perform the same tasks as traditional electromechanical relays, but offer advantages.

An electromechanical relay is a device that uses electrical energy to move a disk, cup, or lever arm to actuate some type of control, usually to trip a breaker. Such actions are needed to ensure that the right amount of electricity is being produced, that it is flowing in the right direction, and that all systems are functioning properly. The advantages of microprocessor-based relays come primarily from the fact that, compared with electromechanical relays, they do not have as many moving parts or require the same amount of maintenance.[11]

More specifically, a single microprocessor-based relay unit provides increased levels and types of protection compared to a single electromechanical unit. The increased protection available in a single microprocessor-based device allows the installation to be low in cost, relative to the greater number of protective devices required in older electromechanical designs.

Installation of microprocessor-based relays provides the following benefits over leaving electromechanical relays in service:

- Because microprocessor-based relays have no moving parts other than output contacts, required maintenance intervals can be reduced or eliminated without degradation in performance. Maintenance costs can be reduced or eliminated.
- Automatic self-testing alerts operations personnel to relay failures, so that personnel do not have to wait until the next maintenance cycle (or non-operation during a system fault) to identify the failed device.

[11] Due to their relatively high number of mechanical or moving parts, electromechanical relays require a significant amount of maintenance and tend to have a relatively high failure rate compared to microprocessor-based relays. If maintenance is not performed, the relay may not operate when a fault occurs, or may operate when it should not, causing an unnecessary outage. Most urban utilities test their electromechanical protective systems on a regular basis. For example, a typical test cycle for electromechanical relays is annually for generation relays, and every 3 to 4 years for distribution relays and other controls. Electromechanical relays require periodic maintenance for the following reasons:

- They have no ability to self-test or to signal a failure in any part of their critical systems. Should a failure of the device occur and not be detected, a subsequent fault condition may damage or destroy the protected equipment.
- Their operating characteristics are dependent on moving parts, and are thus susceptible to airborne contaminants that can modify their operating characteristics.
- Many are more than 25 years old and are ending their useful and predictable operating lives.
- Regular maintenance is generally required by insurers.

- Microprocessor-based relays have better sensitivity and selectivity for system faults, eliminating unsafe conditions more effectively, while reducing the number of false operations, and thus reducing the number of unnecessary outages.

Microprocessor-based relays are ideal for utilities that may not have specific relaying expertise, since their maintenance requires less expertise and labor than the older electromechanical designs.

Analysis. The economic evaluation for the microprocessor-based relay installation was conducted on a per-plant basis and is show in Table 2-12 and Table 2-13. The data used for the cost of installation and testing of the microprocessor-based relays are based on actual numbers used by EPS working in actual installations in rural Alaska. The level of protection used in these examples is applicable for machines with generating capacities of 500 kW and greater.

No additional outages are assumed if the electromechanical relay is left in place. In reality, it is likely that there would be some outages with a microprocessor-based relay installation, due to the occasional misoperations that are typical of electromechanical relays. In this analysis, however, the avoided cost for outages is assumed to be zero. No additional costs were assumed for potential machine or system damage due to the generally underprotected nature of most electromechanical relay installations. The current generation of microprocessor-based relays offers a full menu of protection functions not usually found in electromechanical, or discrete, installations and thus provides the protected equipment with superior protection from damage.

Given the financial variables shown in Table 2-5 and Table 2-12, net present values for two scenarios of the cost of installations (status quo compared with use of microprocessor-based relays) are shown in Table 2-13.

Table 2-12. Variables Used in Microprocessor-Based Protective Relaying Systems Installation Evaluation

Item	Cost ($)		Interval (No. of Years)	
	Installation	Maintenance	Replacement	Maintenance
Electromechanical	5,000 [a]	17,000	6	3
Microprocessor	46,671	5,000	Not Applicable	10

[a] Replacement cost

Table 2-13. Potential Cost Savings with Microprocessor-Based Protective Relay System

Cost Variable	Net Present Value of Costs per Relay Panel ($)	
	Status Quo [a]	With Strategy Implemented
Relay Installation	Not Applicable	46,671
Relay Maintenance	59,723	2,799
Periodic In-Kind Replacement	6,063	Not Applicable
Net Present Value of Costs	**65,787**	**49,470**
Potential Savings (Cost Savings per Panel)		**16,300**

[a] Continuing to use and install electromechanical relays

If it is assumed that a typical community has three generators and three relay panels, the net present value of installing microprocessor-based relay systems is approximately $49,000. When viewed on an annual basis, this savings is not sufficient to reduce the cost of electricity by $0.01 per kWh.

Conclusion. The potential cost savings indicate that the installation of microprocessor-based protective relaying systems should be considered for PCE villages. However, the cost savings do not appear to be sufficient to reduce the cost of electricity by $0.01 per kWh. As a result, this strategy is not recommended for the next stage of the Rural Energy Plan.

2.4 Conclusions and Recommendations

The installation of automated switchgear appears to be a cost-effective strategy that has the potential to significantly reduce the cost of electricity to a large number of residents in rural Alaska. A comparison of costs and benefits associated with this strategy shows that it would provide positive net benefits under reasonable assumptions, and the potential fuel savings would reduce the cost of electricity by more than $0.01 per kWh for numerous utilities (those that do not already have automated switchgear). Based on this potential, the installation of automated switchgear is recommended for further study in the Rural Energy Plan.

Other types of switchgear improvements appear to offer benefits that exceed their cost, but the benefits do not appear to be significant. In particular, the incremental value beyond what can be realized with automated switchgear does not appear to be significant. For example, the installation of RTED controls appears to be cost-effective, but would result in fuel savings in the range of only 3 to 5 percent. With fuel costs at approximately $0.09 per kWh, a 3 to 5 percent reduction would not reduce the cost of electricity by $0.01 or more (a 5 percent reduction corresponds to $0.0045 per kWh). The addition of RTED to a generator automation switchgear upgrade should be considered a viable option, and should be considered for PCE communities where multiple machines are online simultaneously. However, this strategy is not recommended for further study in the Rural Energy Plan as a standalone strategy. It appears that the potential of RTED controls would be maximized if the installation of such controls is considered at the same time as automated switchgear.

Microprocessor-based engine controls are recommended for further study based on the potential that Precision Power and AVEC believe exists with this strategy. Additional data have been requested from engine manufacturers to conduct the proper analysis.[12] The installation of microprocessor-based protective relay systems is also recommended for further study based on the clear advantage of microprocessor-based systems over the traditional electromechanical systems.

Improving or upgrading the various components described in this section offers a variety of possible benefits, including improved fuel efficiency and reduced equipment maintenance. In many instances the potential benefits from improved switchgear, controls, and relays are cumulative and can be captured with incremental expenditures. For example, if a utility already has certain improved equipment in place, or has made the decision to install automated switchgear, it could then consider the incremental costs and benefits associated with additional or more sophisticated components. The sequencing of components should be considered as this strategy is developed in the next stage.

[12] The analysis of microprocessor-based engine controls should include an analysis of the efficiency of existing equipment. (Potential efficiencies must be compared to existing efficiencies to determine the value of possible improvements.) This analysis should include an assessment of the size and condition of existing generator units, as well as specific issues related to operations and maintenance of generator units in rural Alaska.

3 Fuel Price Strategies

Summary

Fuel price strategies include actions fuel users can undertake to achieve lower costs for fuel purchases, such as consolidating fuel purchases to obtain quantity discounts, and evaluating alternative transportation modes, such as air transport, for fuel delivery. The results of this preliminary analysis suggest that:

- The various strategies for reducing the cost of fuel purchases are not significant independently, but can be combined into a program that achieves moderate savings.
- Air transport is unlikely to provide savings when compared to barge delivery of fuel, but lengthening runways could enable the use of larger aircraft and lower air transport costs in those communities where fuel must be delivered by air or when barge service is not available.
- The potential benefits from runway lengthening are likely to outweigh the costs only in a small number of communities.

None of the fuel price strategies is recommended for further evaluation in Phase 2. However, AIDEA and other sponsors should seek opportunities to disseminate information on the activities that certain organizations use to reduce fuel prices, and encourage ADOT&PF to consider reductions in fuel delivery costs in future evaluations of airport projects.

3.1 Introduction

This section describes existing conditions and strategies that relate to lowering the cost of fuel in rural Alaska. This section also provides an analysis of potential net benefits that could be realized by specific fuel cost reduction measures. Detailed analyses and value estimates are provided for the following measures:

- Promoting competition
- Consolidating fuel purchases
- Enhancing understanding of fuel markets
- Replacing Diesel No. 1 by using additives or blending fuels
- Alternative delivery methods

The section ends with conclusions and recommendations.

3.2 Existing Conditions

The high cost of electric power and heating in rural Alaska has motivated a number of electric utilities and other fuel consumers to seek ways to reduce the price they pay for diesel and heating fuel. Interviews with fuel suppliers, utilities, and other consumers suggests that a number of larger fuel users in the state have developed sophisticated approaches to minimizing fuel costs. These organizations use their understanding of fuel markets to promote competition, seek cost-effective pricing with the use of multiple fuel price indexes, and take advantage of seasonal fuel price changes. They also consolidate fuel purchases to obtain price reductions from fuel suppliers and fuel transporters. Subsections 3.3.1, 3.3.2, and 3.3.3 provide additional detail on existing conditions for these strategies.

Diesel No. 2 does not flow at temperatures below about 15°F, but Diesel No. 1 is more expensive than Diesel No. 2. Therefore, fuel users are seeking ways to decrease fuel costs by increasing use of Diesel No. 2 and reducing consumption of Diesel No. 1. Some communities have adopted a strategy of blending Diesel No. 1 and No. 2 to reduce their fuel cost. A blend of about 60 percent Diesel No. 1 and 40 percent Diesel No. 2 has been used by some communities to air temperatures of about –25°F. Another similar strategy is to place additives into Diesel No. 2. Additives enable Diesel No. 2 to be used at air temperatures as low as –45°F. Subsection 3.3.4 provides additional detail on the use of these two strategies (blended fuels and additives) in rural Alaska.

Barge delivery of fuel is the least expensive means of transport and, even in those communities where barge service and air delivery of fuel may be comparable in cost, community residents prefer barge delivery because of the large inventory that can be supplied and the sense of security that full storage tanks provide at the beginning of winter. However, some communities are not accessible by barge and fuel deliveries must be made by air transport. In addition, communities may occasionally need air delivery because the barges cannot reach the community because of low water or equipment failure, or the community uses more fuel than anticipated and fuel must be brought in by air before barge service is available. In these instances, communities with short runways pay more than communities with longer runways for fuel transportation because fuel transport companies can use larger aircraft on the longer runways. Subsection 3.3.5 describes the current situation for air transportation of fuel to communities in rural Alaska.

3.3 Analysis of Strategies

3.3.1 Promoting Competition

Overview. Increased competition among fuel suppliers and transportation companies will result in lower costs to consumers. Communities in rural Alaska should solicit competitive bids and should structure the request for bids to enhance competition among firms. This strategy can be implemented by all communities statewide, but opportunities for expanding its use over present levels are limited, and the strategy is not recommended for further study (see consolidation analysis in the next subsection).

Analysis. Some existing fuel cooperatives use competitive bidding, although competition is not present in some regions such as the Upper Kobuk River, where Crowley Maritime is the only barge carrier, or the middle and upper Yukon River, where Northland Services, Inc. (also doing business as Yutana Barge Lines), is the only barge carrier. Unfortunately, there is very little information available on the number of fuel purchasers that do not employ a competitive bidding strategy, or on the volume of fuel that is purchased without seeking competitive bids.

Competition was often the first or second strategy that the interviewed electric utilities mentioned as a strategy they employ to reduce fuel costs. These utilities request competitive bids and structure the bids to promote more competition. For example, McGrath Light & Power offers a 3-year contract in an attempt to encourage fuel suppliers to compete in that regional market. The utility believes that a long-term contract will encourage additional potential competitors to enter the market because the potential supplier would then have a base from which to expand its operations (Propes, 2000).

AVEC bids for fuel deliveries in 2000 indicate that the price difference between the lowest bidder and the second lowest bidder can be as much as 8 percent. However, the price differential between the lowest bidder and the highest bidder can approach 20 percent (Petrie, 2000b). Other utilities believe that competition among suppliers can provide savings of about 5 percent (Propes, 2000). Assuming an average fuel cost of $1 per gallon and an average diesel generating efficiency of 12 kWh per gallon, a fuel cost savings of 8 percent would result in a savings of about 0.7 cent ($0.007) per kWh. At $1.50

per gallon, the same generating efficiency, and a fuel cost savings of 8 percent, the cost of electrical generation would decrease by 1 cent per kWh.

Conclusions. Discussions with electric utility personnel indicated that significant benefits from competition may exist and that larger orders can increase competitive interest. Consolidating fuel purchases through cooperatives or other organized groups is one means of increasing the size of fuel orders and thereby creating more interest among potential fuel supply competitors. Consolidating fuel purchases and promoting competition are therefore considered jointly in the following discussion. (As indicated, these strategies are not recommended for further investigation).

3.3.2 Consolidation of Fuel Purchases

Overview. Consolidation occurs when several entities purchase fuel together. Transactions may involve an administrator who coordinates the purchase and delivery arrangements. Consolidated fuel purchases offer the greatest benefit to entities that purchase small volumes of fuel. For example, an organization that purchases about 20,000 gallons per year could save 10 to 15 percent on the fuel price through consolidation, minus any administrative costs charged by some of the organizations that consolidate fuel purchases. Larger purchasers (organizations that purchase more than 250,000 gallons) could save about 2 to 4 percent of the fuel price, minus any administrative costs if the organization is purchasing through a fuel consolidator.

In a typical rural community, a number of entities may purchase fuel from the same vendor independently of each other. Each entity purchases fuel to meet its own requirements. The fuel price to these entities is a function of the price of the fuel at the refinery gate and the cost of delivery to each purchaser, as well as the price when the order was placed. Prices per gallon decline with larger fuel orders, in part because of the reduced delivery cost per gallon and the suppliers' desire to capture a larger portion of the market. If all entities in a community place one consolidated order, their combined market power can result in lower costs for each entity even if the deliveries are to separate storage tanks.

Several organizations consolidate fuel purchases to reduce fuel costs in Alaska. Some of the organizations are formal cooperatives, while others are brokers that consolidate fuel purchases. The organizations include the following:

- **Alaska Native Industries Cooperative Association (ANICA)** is a cooperative that serves about 25 communities, predominantly in Western Alaska. According to Crowley Maritime, the cooperative purchases about 2 to 3 million gallons of fuel per year on behalf of retail establishments operated by village corporations or village tribal councils, which then sell the fuel to consumers in their communities (Dwight, 2000).
- **AVEC** purchases fuel for the electric utilities that it operates in 51 villages in rural Alaska. The cooperative has established seven regions for fuel consolidation and issues separate bids for each region. The Northwest Arctic Borough School District, Lower Yukon School District, Lower Kuskokwim School District, St. Mary's School District, and Kashunamuit School District (Chevak), consolidated their fuel purchases with AVEC in 2000. AVEC purchases about 6 million gallons annually (Kohler, 2000; Petrie, 2000).
- **Western Alaska school districts** are consolidating fuel purchases to obtain lower prices. The districts make a consolidated purchase of about 4.5 million gallons per year (Dwight, 2000).

- **WAVE Fuels and Transportation** is a subsidiary of Western Alaska Village Enterprise (WAVE), a Native-shareholder-funded company that operates primarily in the Calista region of Western Alaska. WAVE Fuels and Transportation purchases fuel on behalf of its customers and solicits bids from suppliers to deliver the fuel. WAVE serves more than 60 customers in about 45 communities (Hess, 2000). Its primary market area is in Southwest Alaska. The organization purchases about 5 million gallons of fuel on an annual basis and sells the fuel to stores and other retail establishments for subsequent sale in the villages. (Dwight, 2000).
- **Western Alaska Fuel Group** is an informal purchasing group composed of the electric utilities in Kotzebue, Nome, Unalakleet, Dillingham, Naknek, Iliamna, and Igiugig. The group purchases about 6 million gallons annually with a single combined bid request (Kohler, 2000; Dwight, 2000).
- Other major fuel purchases are made by the **fuel terminal operators at Naknek, Bethel, Dillingham, Nome, and Kotzebue**. The terminals function as the primary fuel suppliers in these larger communities, and as storage depots for purchases by nearby villages in the event of a shortage. The terminals are owned by major fuel distributors. For example, Bristol Fuels operates one of three terminals in Dillingham; Crowley Marine and Bonanza Fuel each operate a terminal in Nome; and Crowley Marine Services owns and operates the terminal in Kotzebue.
- **SKW/Eskimos, Inc.** operates as a fuel purchaser for its own account and functions as the bulk fuel purchase coordinator for the North Slope Borough in communities from Point Hope to Kaktovik.
- The **Red Dog Mine** is also a substantial fuel purchaser in Western Alaska, accounting for about 11 to 12 million gallons annually. Proposed expansion of the mine could increase fuel consumption to 17 to 18 million gallons per year (Northern Economics, 1998).

The balance of fuel consumption consists of independent purchases by various cities and village corporations, small retail establishments, aviators, tour guide companies, and construction companies.

Analysis. The total market for heating and diesel fuel in Western Alaska (west of 154°W latitude and all of the Arctic Slope, excluding military and oil and gas operations on the North Slope) is about 160 to 185 million gallons a year. Of this amount, the fishing industry (processing plants and fishing fleets at Unalaska/Dutch Harbor, and other processing plants and vessels elsewhere on the Alaska Peninsula and Aleutian Chain) accounts for about 90 million gallons. Of the remaining 75 to 95 million gallons, very little is not bought under a cooperative or organized group purchase (Dwight, 2000).

The organizations listed above serve a number of communities in Western Alaska. Communities in much of Interior and Southeast Alaska do not belong to organizations that consolidate fuel purchases. It may be that many communities in these regions could benefit from consolidated fuel purchases.

Refineries in Alaska do not offer volume discounts to buyers (Boltz, 2000; Noel, 2000; Payne, 2000). Fuel distributors are the entities that offer volume discounts to purchasers in rural Alaska. The breakpoints for lower prices vary by distributor. Table 3-1 shows a typical discount program for fuel sales in Western Alaska.

Discounts of about 15 percent are available for purchases of more than 100,000 gallons, as compared to purchases of less than 5,000 gallons (Dwight, 2000). Further price reductions for purchases greater than 100,000 gallons result from competition among distributors for market share. According to Yukon Fuels, distributors evaluate the potential transportation cost to the location or locations that must be served and prepare bids based on risk and expected transportation costs (Tagliavento, 2000). There are no set breakpoints at these higher volumes. The price reductions for fuel purchases greater than 100,000 gallons are typically only a few cents per gallon (Dwight, 2000).

Table 3-1. Typical Discount Program for Fuel Sales in Western Alaska

Volume Purchased (No. of Gallons)	Approximate Discount (Percent Reduction from Price for Minimum Volume)
(Minimum Volume) 5,000	Not Applicable
20,000	5
50,000	10
100,000	15
More than 100,000	Negotiable, but may be additional 2 to 4 percent

An electric utility that consumes 20,000 gallons of diesel in a year could save about $2,000 per year if it could obtain savings of 10 cents per gallon by consolidating its purchasing with other organizations to exceed the 100,000-gallon threshold. Assuming an average diesel generating efficiency of 12 kWh per gallon for communities with this level of fuel consumption, the savings of 10 cents per gallon from consolidated fuel purchases would result in savings of about 0.8 cent ($0.008) per kWh; lower generating efficiency would reduce this savings. A utility that consumes 100,000 gallons could save $2,000 to $4,000 if its purchase was consolidated with purchases by other organizations to obtain further price reductions because of larger volumes. Assuming an average diesel generating efficiency of 14 kWh per gallon for communities with this level of fuel consumption, potential savings of 3 cents per gallon ($3,000 divided by 100,000 gallons) results in savings of about 0.2 cents ($0.002) per kWh.

Tank farm consolidation in communities was also evaluated to determine whether that strategy would result in lower fuel prices. Tank farm consolidation can reduce fuel prices through the potential for purchasing fuel in larger volume and reducing tank farm capital and maintenance costs. However, discounts for larger fuel purchases can be achieved merely by placing a consolidated order for delivery to a community, and potential savings from reduced capital and maintenance costs for a consolidated tank farm as compared to a traditional tank storage in a community are minor. In light of these findings, this strategy was not further evaluated.

Administrative costs charged by fuel consolidators, or membership fees for cooperatives, can reduce potential savings. For example, WAVE Fuels charges about 10 cents per gallon for purchases of 5,000 gallons and about 5 cents per gallon for purchases of 400,000 gallons or more (Hess, 2000). Members reportedly have paid $200,000 in fees to join the cooperative, but that fee can be amortized over a wide range of goods that WAVE provides, including fuel. A WAVE member purchasing 5,000 gallons could save about 7 to 9 cents per gallon over the cost of purchasing directly from another supplier, if membership fees are ignored.[13] However, a customer that purchases more than 100,000 gallons may pay more if it purchases fuel through WAVE because the administrative charge may be greater than the potential savings that WAVE could provide, compared to purchasing from another supplier.[14]

Conclusions. Increasing competition and consolidation of fuel purchases can jointly reduce electrical generation costs by more than 1 cent per kWh in areas where competition does not exist and

[13] Assumes a base fuel price of $1 per gallon, minus 17 to 19 cents per gallon savings for the consolidated fuel purchase by WAVE, plus 10 cents per gallon for WAVE's administrative charge.

[14] Assuming a base fuel price of $1.00 per gallon, WAVE can provide a discount of 17 to 19 cents per gallon plus the administrative charge of 5 cents per gallon, for a net discount of 12 to 14 cents per gallon for a very small consumer. A large purchaser could obtain a discount of 15 cents per gallon by buying directly from another supplier.

consolidation does not occur. However, most communities are using these strategies to some degree. As a result, it appears that opportunities for expanded use of these strategies are limited. The strategies are not recommended for further investigation in Phase 2.

3.3.3 Enhancing Understanding of Fuel Markets

Two cost-saving methods used by larger organizations that have enhanced understanding of fuel markets include purchasing fuels during seasonal periods when prices for diesel fuel are historically low, and requesting suppliers to use multiple fuel price indexes and offering the best price possible from the various indexes at the day of loading. The following subsections describe these strategies.

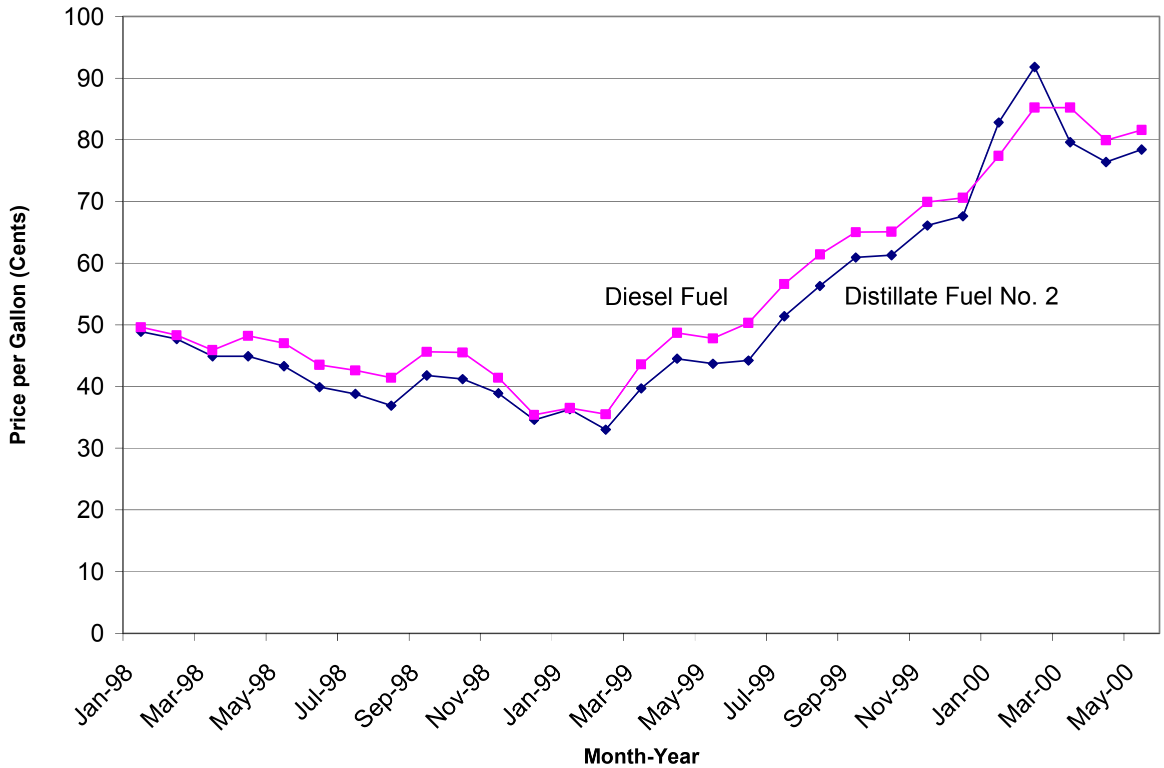
3.3.3.1 Seasonal Purchasing

Overview. Some larger utilities purchase fuel during seasonal periods of low prices and have begun specifying bids in which cost is based on the lowest price among several fuel price indexes. Smaller utilities and communities could employ the same techniques to lower their fuel costs. However, if all communities employ seasonal purchasing, the value of that price reduction strategy may dissipate.

Analysis. According to AVEC and MTNT Electric Limited, periods of low prices typically are near the end of May, when refineries are converting from heating fuel production to gasoline production, and at the end of July or early August, when refineries are converting from gasoline production to heating fuel production (Kohler, 2000; Petrie, 2000; Propes, 2000). At both times there is an increase in inventories of diesel and heating fuels, and a decrease in price for diesel and heating fuels.

Despite this anecdotal evidence, the study team was not able to identify seasonal periods of low prices because of limited availability of data. Figure 3-1 shows monthly national data from the U.S. Department of Energy on refinery prices (excluding taxes) to resellers for diesel fuel and distillate fuel No. 2. It is difficult to discern from the data whether seasonal periods of low prices exist. The trends implied in the figure undoubtedly reflect other market factors that affect prices, and these other factors may mask the seasonal price changes.

Figure 3-1. Distillate Fuel Prices to Resellers, Excluding Taxes, January 1998–May 2000



Source: U.S. Department of Energy, 2000.

Conclusions. Since seasonal price changes cannot be documented at this time, no further analysis of seasonality has been undertaken.

3.3.3.2 Use of Multiple Price Indexes

Overview. This subsection evaluates the strategy of requesting suppliers to use multiple fuel price indexes and to offer the best price possible from the various indexes at the day of loading. The use of multiple indexes provides marginal benefits that may be available only to larger consumers. Further research of this strategy is not recommended, but dissemination of information about the strategy is recommended.

Analysis. There are several indexes used in the trade to establish fuel prices. The Oil Price Information Service (OPIS), the primary source of information on fuel prices, has spot prices and contract prices for distillate No. 2 and jet fuel typically used by fuel suppliers. The Distillate No. 2 prices are quoted for a number of areas including Anacortes, Washington (the location of major Pacific Northwest refineries), Los Angeles, and Alaska. Some of the larger utilities in Alaska are now requesting that suppliers use the index (for example, Distillate No. 2 at Anacortes), plus applicable transportation charges, that provide the lowest price to the utility. Suppliers are responding to that request.

Table 3-2 provides information on various indexes from a sample OPIS newsletter. The prices are higher for Anchorage than for Anacortes or Seattle for several reasons. Contributing factors include economies of scale captured by larger refineries in Washington state, and at least one major disadvantage for each of the major Alaska refiners that increases their costs: the Williams refinery in

Fairbanks must ship fuel in rail cars to Anchorage, the largest market for its products, and the Tesoro refinery must ship its residuals to out-of-state users.

The cost differential between Anacortes and Seattle of 0.8 cent ($0.008) per gallon for No. 2 high-sulfur fuel as shown in Table 3-2 would result in minor cost savings of per kWh of electrical generation for Alaska utilities. However, the use of multiple indexes could lower total fuel costs for consumers, with savings dependent on volume purchased. Competition among fuel and transportation companies must be present to persuade them to offer the best index price to customers. Even then, fuel suppliers will be reluctant to offer index pricing to smaller customers. Consolidated purchases also may be necessary to enable smaller customers to take advantage of lower pricing with multiple indexes.

Table 3-2. Comparison of Index Prices for No. 2 Distillate Fuel, Week of April 28, 1998

Terminal Location	Average Price for No. 2, High-Sulfur Fuel (Cents per Gallon)
Anacortes	43.03
Anchorage	64.33
Seattle	43.83

Source: OPIS Energy Group, 1998.

Conclusions. The use of multiple indexes provides benefits to organizations that employ the technique. However, these benefits are marginal and may be available only to larger consumers. Further research of this strategy is not recommended, but dissemination of information about the strategy should be undertaken.

3.3.4 Replacing Diesel No. 1 by Using Additives or Blending Fuels

There are more Btus in Diesel No. 2 than in Diesel No. 1, but Diesel No. 2 will not flow at cold temperatures below about 15°F. As a result, many communities in the state use Diesel No. 1 during winter months. However, Diesel No. 1 is more expensive than Diesel No. 2, so some communities have developed strategies to reduce their use of Diesel No. 1. One strategy is to use recovered heat or some other mechanism to heat bulk fuel tanks, using large-diameter pipe (3 to 4 inches) to feed from unheated tanks, and using snow for insulating these pipes during cold weather. Other strategies include using additives with Diesel No. 2 and blending fuels to reduce their consumption of Diesel No. 1. The following subsections describe these strategies in more detail.

3.3.4.1 Using Additives

Overview. This strategy focuses on the opportunity for communities to purchase additives[15] to reduce the pour point (the temperature at which the fuel begins to thicken) of Diesel No. 2 and reduce fuel costs by about 5 cents per gallon compared to Diesel No. 1.

Analysis. With additives, communities can use less expensive Diesel No. 2 rather than more expensive Diesel No. 1, at least during certain parts of the year. This strategy is applicable in areas of the state

[15] The current generation of additives, also known more formally as middle distillate fuel pour point depressants, have a polyethylene structure with a polar copolymer (vinyl acetate) to make the product stick to wax nuclei that are found in the fuel. There are varying opinions about the precise mechanism by which the additives function, but the consensus is that the additives inhibit wax crystal growth in distillate fuels (Emtec, 2000).

where Diesel No. 1 is required during colder months, but in locations where temperatures are not likely to fall below –45 ° F. AVEC and MTNT reported that they use Diesel No. 2 with an additive for temperatures down to about –45°F.

The use of an additive increases the cost of a gallon of Diesel No. 2 or similar heating fuel by about 1 to 3 cents per gallon, excluding costs for any additional tankage that may be required. In comparison, Diesel No. 1 costs about 10 to 12 cents more per gallon than Diesel No. 2 (Baumgartner, 2000). In some communities, additional tankage may be required since the additive is added at the refinery and the blended fuel must be separate from other fuels.

In April 2000, the difference in end user price for No. 1 and No. 2 distillate from Alaska refineries was 8.2 cents per gallon. In Washington, the difference was 12.3 cents for sales for resale (sales to end users were withheld to avoid disclosing individual company data) (U.S. Department of Energy, 2000). If the difference in cost between Diesel No. 1 and Diesel No. 2 with additive is 5.2 cents per gallon,[16] an electric utility located where temperatures not expected to fall below –45°F and consuming 100,000 gallons of Diesel No. 1 per year could save about $5,200 annually. Assuming an average diesel generating efficiency of 14 kWh per gallon for communities with this level of fuel consumption, the average savings would be about 0.37 cent ($0.0037) per kWh. At an average diesel generating efficiency of 10 kWh per gallon, the average savings would be about 0.52 cent ($0.0052) per kWh.

There are other benefits with this strategy. Diesel No. 2 provides more lubrication than Diesel No. 1, reducing wear on engines. Diesel No. 2 has more Btus per gallon than Diesel No. 1, and this factor translates into additional savings for heating fuel consumers. The additional British thermal unit (Btu) value of Diesel No. 2 theoretically should translate into higher generating efficiencies (more kWh per gallon) than are possible with Diesel No. 1. However, interviews with utility representatives indicated that this differential could not be measured practically at operating utilities in rural Alaska because of other factors (such as varying load) that mask potential gains from use of Diesel No. 2 (Petrie, 2000; Baumgartner, 2000).

Conclusions. It is recommended that this strategy not be included in the Phase 2 investigations. The marginal cost savings associated with this strategy, and the likelihood that this strategy will be adopted readily by utilities where it is appropriate, suggest that further assessment is not necessary.

3.3.4.2 Blending No. 1 and No. 2 Diesel Fuels

Overview. The strategy of blending No. 1 and No. 2 diesel fuels could be implemented year-round in more temperate regions of the state, and during spring and fall in colder regions. However, unexpected cold temperatures or human error could lead to major problems with heating and generation equipment. It is advised that this strategy be used only in electric utilities, and only by communities with a record of good operating practices. The blend would need to be stored in a separate tank or tanks. Additional tankage may need to be constructed in some communities.

During months when Diesel No. 2 cannot be used, a blend (60 percent Diesel No. 1 and 40 percent Diesel No. 2) could be used if the temperature does not fall below about –25°F.[17] McGrath Light & Power, which uses a blend for about 4 to 6 weeks in fall and 6 to 8 weeks in spring, consumes about 55,000 gallons of blended fuel per year for electrical generation.

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[16] 8.2 cents per gallon at Alaska prices minus 3 cents per gallon for additive

[17] These temperatures are based on interviews with fuel purchasers and suppliers. Refiners can modify the point at which wax crystals begin to form, although the process is not precise (Emtec, 2000).

Analysis. At McGrath Light & Power, blended fuels represent about 21 to 23 percent of total fuel consumption, which ranges between 235,000 and 260,000 gallons per year (Baumgartner, 2000). At a savings of $0.05 per gallon,[18] the utility saves about $2,750 per year with this strategy. Using the average diesel generating efficiency of 13.4 kWh per gallon for McGrath from annual reports submitted to the Regulatory Commission of Alaska (Melendez, 2000), this strategy would reduce average annual electricity generation costs by about 0.4 cents ($0.004) per kWh. Neither the use of additives nor the blending of fuels to reduce use of Diesel No. 1 results in significant savings by itself. However, employing these strategies in conjunction with increased competition, consolidated fuel purchases, and multiple indexes can result in a moderate level of aggregate savings.

Conclusions. It is recommended that this strategy not be included in the Phase 2 investigations. The marginal cost savings associated with this strategy, and the likelihood that this strategy will be adopted readily by utilities where it is appropriate, suggest that further assessment is not necessary.

3.3.5 Alternative Delivery Methods

3.3.5.1 Fuel Deliveries by Air

Overview. The strategy discussed in this subsection involves use of aircraft rather than barges to deliver fuel to rural communities. In general, this strategy could be implemented statewide, but the largest benefits would accrue in communities with short runways and the following characteristics:

- The community is accessible solely by air transportation.
- Barge access is unreliable due to low water or other factors.
- The community cannot afford to purchase fuel in large volumes.
- The cost of air transportation is competitive with the cost of barge transportation.

Air carriers believe that there may be 40 to 50 communities in the state that regularly receive all or a major part of their fuel by air. In addition, a number of communities receive fuel deliveries in the spring if the barges are running late or if the community has used more fuel than anticipated.

Analysis. Interviews with air carriers (Greatland Air Cargo, Northern Air Fuels, and Everts Air Fuels) did not identify communities that presently receive fuel by barge that would reduce their cost of fuel by switching to air delivery. However, there may be communities that receive fuel by air that could save on fuel costs if runways were lengthened to accommodate larger cargo aircraft. Larger cargo aircraft can reduce the air transportation cost per unit of fuel delivered to communities. Occasionally, communities accessible by barge are short of fuel in spring before barges arrive and must order fuel deliveries by air. Communities facing this situation could benefit from longer runways.

Telephone interviews were conducted with tug and barge operators and air fuel delivery services in an attempt to identify communities that are served by barge fuel delivery and might be able to obtain fuel at lower prices if they switched to air delivery. None of the companies contacted (Yukon Fuels, Greatland Air Cargo, Northern Air Fuels, Everts Air Fuels) could identify communities where air delivery of fuel might be less expensive than barge service. Everts Air Fuels indicated that even if the price was the same or lower for air transport than for barge service, barge service would be preferred in rural Alaska because ability to deliver a large inventory of fuel provides a greater sense of security for the community at the beginning of winter (Wing, 2000). The air carriers stated that air delivery fuel

[18] If the blended fuel uses 40 percent Diesel No. 2 and the cost savings for using Diesel No. 2 instead of Diesel No. 1 is about 12 cents per gallon, the savings per gallon of blended fuel compared to Diesel No. 1 is about 4.8 cents.

costs could be reduced if longer runways were available and larger aircraft could be employed. This subsection focuses on identifying the potential fuel cost savings from developing longer runways.

The following paragraphs in this subsection:

- Provide a range of potential costs for lengthening existing runways or constructing new runways
- Identify the potential cost savings from using larger aircraft for fuel deliveries or enabling aircraft to operate with larger payloads
- Compare the net present value of these savings over 25 years with the potential construction cost

A series of tables, Table 3-3, Table 3-4, Table 3-5, Table 3-6, and Table 3-7, illustrate the analysis, which uses the communities of Nikolai and Amber as examples. These tables are grouped together after the following discussion for ease of interpretation.

The Alaska Department of Transportation and Public Facilities (ADOT&PF) builds and maintains most rural Alaska airports. ADOT&PF provided a range of typical costs to lengthen and build runways in rural Alaska (Mayo, 2000). The costs range from a low of $1,000 per lineal foot to a high of $3,700 per lineal foot for lengthening a runway suitable for handling a DC-6, a typical plane used for fuel deliveries. The costs for a new runway suitable for a DC-6 could range from $3,700 to $5,000 per lineal foot. The range is wide because of the many factors that can affect construction costs.

Table 3-3 presents the range of potential costs for lengthening a runway to a certain length, or constructing a new runway of a certain length, in two case study communities, Nikolai and Ambler. Table 3-4 compares the air transportation costs and savings per gallon that are possible with the use of larger aircraft on a longer runway. The costs of constructing a longer runway are not included.

ADOT&PF maintains a 2,350-foot gravel airstrip in Nikolai. A runway of this size can accommodate Caravans, Cassas, C-46s, and Caribous, cargo aircraft used by Alaska air carriers to transport fuel to short runways. A Caravan has a payload of about 4,200 pounds of cargo (approximately 600 gallons of fuel oil or diesel), while a Cassa has a payload of about 6,000 pounds (approximately 860 gallons). A C-46 can land with approximately 2,000 gallons of fuel at Nikolai (Wing, 2000). A Caribou has a payload of about 7,000 pounds (approximately 1,000 gallons). Everts Air Fuel flies fuel into Nikolai with a C-46, so its cost estimate is used for Nikolai.

ADOT&PF also maintains the 3,000-foot gravel airstrip at Ambler. Northern Air Fuel can land a DC-6 with about 3,000 gallons of fuel on a runway of this length. A Northern Air Fuels DC-6 operating at sea level would require a minimum runway length of 4,000 feet (4,500 feet preferred) for its maximum payload of about 4,000 gallons (Adams, 2000). Everts Air Fuel stated that it can haul 5,000 gallons in its DC-6 aircraft (Wing, 2000). Northern Air Fuel was flying fuel into Ambler when this report was prepared, so its cost estimate is used for Ambler.

Nikolai had a population of about 105 in 1999 and consumed about 55,000 gallons of heating fuel and diesel and 20,000 gallons of gasoline (Dwight, 2000). Current transportation cost for flying the fuel from Fairbanks into the 2,350-foot runway at Nikolai is $1.75 per gallon (Wing, 2000). According to MTNT, the cost of flying fuel into Nikolai is about the same as the barging cost (Propes, 2000). Based on this information, a 4,500-foot runway could save the community about $55,000 per year in fuel costs (75,000 gallons times $0.73 is $54,750). This total represents an annual savings of about $520 for each person in the community. The annual savings per household (with an average of 2.7 persons per household) would total about $1,400, or 10 percent of the total household income of $14,063.[19] With an average diesel generating efficiency of about 10 kWh per hour in Nikolai

[19] Additional information is available online at www.dced.state.ak.us/mra/CF_BLOCK.cfm.

(Melendez, 2000), the fuel cost savings associated with longer runways and larger aircraft would result in the reductions in electrical generation costs shown in Table 3-5.

Ambler, a community of about 286 persons in 1999, consumed about 180,000 gallons of diesel and heating fuel, and 50,000 gallons of gasoline (Dwight, 2000). In 2000, only part of the community's fuel supply was delivered by barge due to low water in the Kobuk River. The balance is being flown in at a cost about 62 cents per gallon higher than the anticipated barge delivery cost (Adams, 2000). The air delivery cost is high because the plane must be flown from Fairbanks to Kotzebue, and then use Kotzebue as a base of operations for delivery to Ambler. Fuel for the plane is much more expensive in Kotzebue than in Fairbanks, reflecting the cost to transport the fuel to Kotzebue.

Less than half of the requested fuel delivery in 2000 was made by barge, but since air deliveries can be made as needed throughout the year, fuel inventories can be kept much lower. With air deliveries, less fuel may have to be delivered to the community for several reasons. First, there is less need to have fuel reserves in case the barge is delayed in the following year; air deliveries can continue to be made until the barge arrives. Second, the cost of fuel in the community will be higher with air deliveries, which will depress consumption by residents and lower fuel requirements.

Assuming that half of the fuel consumption for the 2000-2001 heating season arrives by air, the additional cost to the community will be about $71,000. If the Ambler runway is lengthened to 4,500 feet, fuel costs per gallon could be reduced by about 41 cents. (Air delivery costs would still remain about 21 cents per gallon higher than barge delivery costs.) Lengthening the runway could reduce fuel costs by about $47,000 or about $165 per person. Median household income is about $22,500 (Alaska Department of Community and Economic Development [DCED], 2000). The annual savings per household (with an average of 4.3 persons per household) would total about $700, more than 3 percent of annual household income. Using an average diesel generating efficiency of about 13.95 kWh per hour for Ambler, and half of the annual fuel consumption of about 85,200 gallons for electrical generation (Petrie, 2000), the fuel cost savings associated with longer runways and larger aircraft would result in the reductions in electrical generation costs shown in Table 3-6.

Table 3-7 compares the net present value—project benefits minus project costs—of savings that would accrue to each community if runways were lengthened and **all** fuel moved by larger aircraft. An example with all fuel being moved may be representative of the situation in communities that are totally dependent on air delivery, such as Venetie (4,100-foot runway) or Hughes (3,400-foot runway) where barge service is unreliable and most fuel and heavy freight is brought in by air (DCED, 2000).

The net present value of savings was calculated for a 25-year period with a 3 percent real discount rate. No population growth or subsequent growth in fuel consumption was assumed. No reductions in interest costs for fuel supplies delivered by air are included. The net present value of fuel cost savings in Nikolai does not exceed the construction cost for any of the runway lengths evaluated in Table 3-7. In contrast, Table 3-7 suggests that the benefits of lengthening the runway in Ambler to 4,500 feet would exceed the construction cost if such costs could be kept to about $1,000 per lineal foot.

Longer runways or new, larger runways offer several other potential benefits not addressed in detail in this analysis. For example, delivery by air can occur throughout the year, reducing the tank capacity needed in a community. Communities with barge deliveries typically have adequate tank capacity to hold 12 to 18 months of fuel supplies. With air delivery, communities may need tank capacity for only a few weeks or months of fuel consumption. In addition, longer runways would enable larger aircraft to be used for other cargo, mail, and passengers. The potential cost savings and other benefits that longer runways would provide for these other uses have not been calculated.

Ultimately, longer runways can reduce fuel costs for villages that obtain fuel deliveries by air. Table 3-7 suggests that small communities with lower fuel requirements, like Nikolai, are not likely to achieve fuel cost savings that outweigh the cost of lengthening or constructing new runways. Larger communities may be able to achieve fuel cost savings that are larger than runway construction costs if such construction costs can be held to a minimum. Factoring in other cost savings could substantially improve the economics of lengthening runways.

Table 3-3. Range of Construction Costs for Lengthening Runways and Constructing New Runways at Nikolai and Amber

Runway Length Alternative (Feet)	Additional Length Required (Feet)	Cost to Lengthen Runway ($) Low ($1,000 per Lineal Foot)	Cost to Lengthen Runway ($) High ($3,700 per Lineal Foot)	Cost for New Runway ($) Low ($3,700 per Lineal Foot)	Cost for New Runway ($) High ($5,000 per Lineal Foot)
Nikolai (Existing length 2,350 feet)					
3,000	650	650,000	2,405,000	11,100,000	15,000,000
4,000	1,650	1,650,000	6,105,000	14,800,000	20,000,000
4,500	2,150	2,150,000	7,955,000	16,650,000	22,500,000
5,000	2,650	2,650,000	9,805,000	18,500,000	25,000,000
Ambler (Existing length 3,000 feet)					
4,000	1,000	1,000,000	3,700,000	14,800,000	20,000,000
4,500	1,500	1,500,000	5,550,000	16,650,000	22,500,000
5,000	2,000	2,000,000	7,400,000	18,500,000	25,000,000

Note: Representatives of air cargo companies that deliver fuel suggested building fuel tanks with a pipeline system to offload airplanes at airstrips if a pipeline does not exist from the airstrip to the community fuel tanks. The cost estimates do not include such a pipeline or tank system.

Table 3-4. Air Transportation Cost Savings with Longer Runways at Nikolai and Amber

Runway Length Alternative (Feet)	Amount per Gallon ($) Air Transport Cost [a]	Amount per Gallon ($) Savings
Nikolai		
2,350 (Status Quo)	1.75	-
3,000	1.70	0.05
4,000	1.33	0.42
4,500	1.02	0.73
5,000	1.02	0.73
Ambler		
3,000 (Status Quo)	1.63	-
4,000	1.33	0.30
4,500	1.22	0.41
5,000	1.22	0.41

[a] Cost estimates are for air transport only and do not include construction costs or the time required by community members to meet aircraft or move the fuel in tank trucks or trailers to the existing community tanks. In some communities with small (500-gallon) tank trucks, multiple trips can be required for each planeload of fuel.

Table 3-5. Electrical Generation Cost Savings with Longer Runways at Nikolai

Runway Length Alternative (Feet)	Air Transport Cost Savings Per Gallon ($)	Electrical Generation Cost Savings for Fuel Delivered by Air	
		Annual ($) [a]	Per kWh (¢)
2,350 (Status Quo)	NA	NA	NA
3,000	0.05	1,720	0.5
4,000	0.42	14,430	4.2
4,500	0.73	25,080	7.3
5,000	0.73	25,080	7.3

[a] Based on 34,359 gallons of diesel fuel used for electrical generation between July 1, 1998, and June 30, 1999 (Melendez, 2000).

Table 3-6. Electrical Generation Cost Savings with Longer Runways at Ambler

Runway Length Alternative (Feet)	Air Transport Cost Savings Per Gallon ($)	Electrical Generation Cost Savings (for Fuel Delivered by Air)	
		Annual Savings ($) [a]	Per kWh (¢)
3,000 (Status Quo)	NA	NA	NA
4,000	0.30	12,800	2.1
4,500	0.41	17,500	2.9
5,000	0.41	17,500	2.9

[a] Based on 85,200 gallons of fuel used for electrical generation in 1999 (Petrie, 2000).

Table 3-7. Comparison of Construction Cost and Net Present Value of Transportation Cost Savings at Nikolai and Amber

Runway Length Alternative (Feet)	Net Present Value of Savings ($)	Cost to Lengthen Runway ($)		Cost for New Runway ($)	
		Low ($1,000 per Lineal Foot)	High ($3,700 per Lineal Foot)	Low ($3,700 per Lineal Foot)	High ($5,000 per Lineal Foot)
Nikolai					
3,000 (Status Quo)	65,300	650,000	2,405,000	11,100,000	15,000,000
4,000	548,500	1,650,000	6,105,000	14,800,000	20,000,000
4,500	953,400	2,150,000	7,955,000	16,650,000	22,500,000
5,000	953,400	2,650,000	9,805,000	18,500,000	25,000,000
Ambler					
4,000 (Status Quo)	1,201,500	1,000,000	3,700,000	14,800,000	20,000,000
4,500	1,642,100	1,500,000	5,550,000	16,650,000	22,500,000
5,000	1,642,100	2,000,000	7,400,000	18,500,000	25,000,000

Conclusions. ADOT&PF should further evaluate communities in which benefits of runway lengthening might exceed the costs of construction. Phase 2 should not include further research on this strategy.

3.4 Conclusions and Recommendations

Air delivery of fuel usually is not competitive with barge delivery due to cost and consumer preference. However, air transportation costs can be reduced if longer runways are constructed. Smaller communities are unlikely to achieve benefits that are large enough to offset the cost of lengthening runways. Larger communities may be able to achieve enough benefits to offset the costs of lengthening runways by using larger aircraft to deliver fuel and other cargo, and to transport passengers, and if construction costs can be kept low. The benefits of this strategy are likely to accrue to a relatively small number of communities in the state. Therefore, this strategy is not recommended for further evaluation in the Rural Energy Plan. It is recommended that ADOT&PF consider and include the benefits of lower fuel costs when evaluating airport projects in the future.

The other fuel price strategies each provide relatively minor savings in the cost of electrical generation in rural Alaska. However, these strategies can be combined in a program to reduce fuel prices that achieves a moderate level of savings for electrical generation and heating. Many utilities and other consumers have implemented at least some of these strategies. Consequently, the potential savings may be limited to those communities that are not familiar with the strategies. Additional research in Phase 2 is not recommended, but AIDEA should seek opportunities to disseminate information on a programmatic approach to reducing fuel costs. Organizations that currently use these strategies should be approached to discuss these strategies at relevant conferences and meetings so that other organizations can benefit from their understanding and knowledge.

4 End-Use Conservation

4.1 Introduction

Summary

This preliminary analysis indicated the following:

- End-use conservation measures have the potential to significantly reduce the cost of electricity in rural Alaska. Estimates of the potential net present value from investing in the end use conservation measures discussed in this subsection exceed $34 million.
- Further research on end-use conservation measures in Phase 2 is justified based on the potential savings of these measures.

This section describes existing conditions related to end-use conservation, including sources of information on end-use conservation measures and programs designed to promote such measures in rural Alaska. This section also provides an analysis of potential net benefits that could be realized with specific measures. Detailed analyses and value estimates are provided for the following measures:

- Installation of energy-efficient lighting systems in existing residences and new residences
- Upgrades to energy-efficient refrigerator-freezer units
- Upgrades to energy-efficient televisions

This section ends with conclusions and recommendations for additional research. The analyses of strategies that involve fuel switching, such as conversion of electric water heaters to oil heaters, are in Section 7, Space and Water Heating. Strategies such as additional insulation, heater retrofits, and weatherization measures are also analyzed in Section 7.

4.2 Existing Conditions

4.2.1 Major Programs

Several entities have programs to promote energy efficiency in rural Alaska. Programs in the state include the following:

- The Alaska Industrial Development and Export Authority Rebuild America program
- The Rural Alaska Community Action Program Energy Conservation Initiative
- Other weatherization and technical assistance programs sponsored by the Alaska Housing Finance Corporation
- The Cold Climate Housing Research Center
- The Alaska Craftsman Home Program
- The Alaska Building Science Network

The **Alaska Energy Authority (AEA)**, the programs of which are administered by AIDEA staff, uses U.S. Department of Energy funds along with state matching funds to promote energy saving in Alaska through several initiatives. These initiatives include the **Rebuild America** program (implemented in Alaska as **Rural Alaskans Conserve Energy** [**RACE**]), technical assistance for energy retrofits, and other programs that target specific industries such as seafood. Through the Rebuild America initiative, AIDEA has a proven history of replacing old lighting systems with new, energy-efficient systems and making other improvements in the area of energy efficiency. For example, a project to upgrade old fluorescent lamps in the Aniak High School Gym in 1999 reduced the school's lighting bill by 20 percent. The total cost of the project was $12,892 (including a grant of $11,392 from AEA and $1,500 from the Kuspuk School District, and the estimated payback period is 20 months (figures from Rebuild America program database, provided by Rebecca Garrett, program director).

RurAL CAP sponsors the **Energy Conservation Initiative**—a collaboration between the AmeriCorps Program and the Energy Assistance Program at the Alaska Department of Health and Social Services. The project is intended to decrease dependency on public assistance by measurably reducing the energy costs of more than 2,000 low-income households. The project was designed with input from low-income people across the state, along with technical information from Alaska's home energy conservation and weatherization fields (RurAL CAP, 2000).

The **Alaska Housing Finance Corporation (AHFC)** offers a variety of programs, from low-cost loans for energy-efficient structures to technical assistance. While the Rebuild America program focuses on institutional buildings (for example, schools, stores, and post offices), AHFC programs focus on residential buildings. AHFC promotes energy efficiency by financing the purchase of those homes, and only those homes, that meet minimum building energy efficiency standards. For new construction, meeting these standards requires a home energy rating for the new house plans and an "as-built" rating once the home is complete. (Contractors certified by AHFC perform these services.[20]) Homes meeting certain criteria are approved for interest rate reductions. Buyers of existing homes can participate in the interest rate reduction program by increasing a home's energy rating and including the cost of specific improvements into the mortgage.

Other programs function more as information clearinghouses. For example, the **Alaska Craftsman Home Program, Inc.** and the **Alaska Building Science Network** are associations that promote energy efficiency as an essential component of durable, safe, and affordable housing in Alaska. In addition, organizations such as the **Cold Climate Housing Research Center and** the **Northern Research and Technology in Housing** test new building technologies in Alaska and northern Canada, respectively.

In addition, programs in Canada offer information and training to promote energy conservation in new construction and renovation projects in cold climates. Available data on these programs suggest that considerable savings can be realized through end-use conservation. For example, replacing a 60-watt incandescent light bulb with a 13-watt compact fluorescent bulb will reduce the consumption of electricity for lighting by approximately 80 percent (*Fine Homebuilding*, Winter 1999, No. 127).

Information on the success of programs designed to promote energy efficiency is limited by a lack of data on historical electricity consumption by residences and institutional buildings in rural Alaska. In addition, problems arise when assessing the value of various energy retrofit projects because there is no clear mechanism for determining the value of each component of projects that typically include weatherization, installation of new lighting systems, and installation of new, energy-efficient appliances and heaters. Projects may also include converting some appliances from one energy source to another (for example, replacing electric water heaters with oil-fired water heaters).

Data from Past Efforts

The Rebuild America program maintains a database with information collected from energy audits in 85 communities in rural Alaska. The database is a Microsoft Access database, with data on the

[20] New homes that achieve a 4 Star Plus AkWarm energy rating or better meet the energy standard. A higher rating such as 5 Star or 5 Star Plus qualifies the homebuyer for an energy-efficiency interest rate reduction through AHFC.

communities and approximately 3 to 4 institutional buildings in each community. Building-specific data include the type of structure, building age, square footage, type of fuel used for heating, special energy load features (such as a swimming pool), and total annual energy load. Paper records completed during the audits show the type of heating system and lighting in each building. This more detailed information has not been included (at this date) in the Access database.

Rebuild America energy audit data include energy conservation recommendations,[21] the estimated cost of projects, the associated savings, and the estimated payback period. Payback periods for these efforts range from 0.5 to 4.9 years. Common recommendations in the audit include the following:

No-Cost Measures

- Set the temperature back 10 degrees on thermostats at night and on weekends
- Turn out the lights when no one is using the room
- Delamp in over-lit areas
- Reduce temperature on hot water heaters
- Switch to compact fluorescent fixtures when incandescent bulbs burn out

Low-Cost Measures

- Programmable setback for thermostats
- Install timers with battery back up on vending machines
- Install LED exit lights
- Replace T-12 fixtures with T-8 fixtures with electronic ballasts
- Install occupancy sensors on lighting controls
- Install time clocks on exhaust fans in bathrooms and shower areas
- Install outside temperature setback on boiler
- Replace inefficient motors, pumps, and fans

Through AIDEA, Rebuild America has implemented a small portion of the projects recommended in the audits. Little or no data are available on the effectiveness of these projects—many have just been completed.

Data from other programs are also limited. For example, AHFC maintains a database on manufacturer specifications for a variety of products and keeps limited records of building conditions (such as the energy rating) where buildings have been financed by AHFC. AHFC does not have data on the types of lighting fixtures, heating systems, and other appliances in existing homes. The contractors that work with AHFC also have limited records with information on houses where they have conducted audits, completed weatherization upgrades, or installed new heating equipment.

Data from the Alaska Department of Community and Economic Development (DCED), Division of Business and Community Development, include information on fuel usage, electricity consumption, and electricity prices for rural communities. However, no information is available in this database on how the fuel or electricity is used. In particular, no information is available on the type or efficiency of heating systems or lighting systems that are in place in rural Alaska. (Such data are needed to determine the extent to which end-use conservation strategies are being used in rural Alaska or to

[21] Including no-cost measures such as delamping fixtures in over-lit areas or keeping lights off in unoccupied areas, low-cost measures such as replacing mercury vapor lighting with fluorescent fixtures, and capital projects with a cost of more than $5,000

assess the potential for savings from continued effort in this area.) U.S. Census data show the type of fuel used for heating in Alaska, but are less detailed than the data provided by the Division of Business and Community Development.

In summary, no data are available to identify the type of heating equipment used in rural Alaska, the amount or type of insulation, the type of lighting, or the efficiency of various appliances.

Anecdotal Information

Weatherization contractors such as the Rural Alaska Community Action Program (RurAL CAP) and Alaska Community Development Corporation (ACDC) have very limited primary data on the value of the weatherization and energy retrofit projects they have completed. Data problems include the inability to collect data on historical energy use from private utilities, and inability to afford the data loggers and necessary software to monitor project performance properly.[22] For example, ACDC recently replaced electric hot water heaters in the City of Egegik (where each electric water heater added approximately 4.5 kW to system load). ACDC personnel explained that savings cannot be calculated because the private utility has not responded to requests to provide ACDC or the City of Egegik with copies of billing histories for residences that received new heaters (Berube, 2000). Personnel at both RurAL CAP and ACDC said that recent projects are being monitored, but data are not available for past projects.

4.2.1.1 Village Case

Igiugig Project

ACDC and AHFC recently completed energy retrofits in 13 buildings in Igiugig. Retrofits were conducted in December 1999 and March 2000, and most of the buildings were residences. Improvements included weatherization, replacing lighting systems, and upgrading appliances where appropriate. The purpose of the project is to conduct an electrical baseload management study and to determine the value of conducting such retrofits in a majority of the buildings in a community.[23] Personnel at ACDC said that a preliminary review of the data suggested that efficiency improvements have resulted in a 10-kilowatt (kW) reduction in system load. They also said that a comparison of electric data for the winters of 1999-2000 and 2000-2001 will give a clearer picture of the change in electricity usage. ACDC is currently preparing a report that will show the projects implemented, the project costs, and expected savings. Staff at ACDC are constructing billing histories for the buildings in the study. (Factors such as unexpected use of electric space heaters in a building used during a road construction project complicate the data collection for this effort.)

4.3 Analysis of Strategies

This subsection presents estimates of the potential benefits of end-use conservation measures that could be implemented in rural Alaska. Cost estimates for different actions are derived from estimates

[22] Many projects implemented by the weatherization contractors have multiple components. For example, a single project may have components to improve thermal efficiency, to improve building durability and safety, and to conserve electricity. Determining what portion of a project's costs and benefits should be attributed to electricity and having the equipment to monitor project components separately presents the contractors with a difficult set of issues.

[23] Igiugig was selected because of its manageable size, city-managed utility (minimizing problems with access to data), and interest on the part of the city manager and utility manager.

in other studies (especially the 1988 report by Analysis North, *The Economic Potential of Energy Efficiency in Rural Alaskan Residences*) and comments from weatherization contractors and program managers. Total cost figures are based on the average existing cost of electricity in rural Alaska ($0.15 per kWh for avoided costs and $0.32 per kWh for retail costs) and $1.00 per gallon for fuel. Net present value calculations are based on a discount rate of 3 percent and various planning periods depending on the end-use conservation measure being analyzed.

Rural Energy Enterprises (a subsidiary of RurAL CAP) is a wholesale distributor of energy-saving products for rural Alaskans. Company director Conrad Zipperian believes that great strides have been made in changing the way rural Alaskans heat their homes, but little progress has been made in the area of lighting. He cited stove sales for Rural Energy Enterprises in the recent past and efforts of other weatherization contractors as evidence that a significant percentage of rural Alaska homes are now using efficient heaters. However, Rural Energy Enterprises had minimal success selling compact fluorescent light fixtures in the past and stopped carrying compact fluorescent products. Several weatherization contractors suggested that new heaters have been readily accepted by rural Alaska residents for reasons such as convenience and performance, in addition to efficiency. In comparison, compact fluorescent lights have not been more convenient to use or have not provided other obvious benefits to offset the high capital cost (Zipperian and Lee, 2000).

Evidence for the potential of end-use conservation in space and water heating is in Section 7. The following text focuses on the potential of efficient lighting systems and other technologies related to reducing the cost of electricity in rural Alaska.

Estimates from Previous Studies

In its 1988 report, Analysis North analyzed economic benefits and costs of energy efficiency measures such as improving heating systems, superinsulating new homes, and upgrading lighting systems. For the 20,000 PCE households (the estimated number at the time of the study), the authors found that the net present value of investing in these energy efficiency and conservation measures was $240 million, or $12,000 per household. (The present value of total potential benefits was estimated to be $370 million, while the present value of costs was estimated to be $130 million.)

Techniques examined in the 1988 Analysis North study were space heating efficiency improvements (including replacing heating systems, increasing insulation, improving window systems, and reducing air leakage in homes), electrical end-use efficiency improvements (lighting, refrigeration, and other appliances), and fuel switching possibilities (replacing electric water heaters with oil-fired units). Focusing on electrical end-use efficiency improvements, Analysis North found that for each kWh of electric load reduced, savings in terms of avoided generator costs were approximately $0.125. This avoided cost figure was based on the cost of fuel and generator efficiency, not the retail value of a single kWh of electricity.

The study found that "…significant economic benefits could be realized from the implementation of energy-efficient measures in existing and future rural residences" (page 5). The study also noted, however, that many measures would not be implemented by the unaided marketplace. For example, the study showed that space heating efficiency levels that were economically optimal based on life-cycle costing exceeded state thermal standards. The authors assumed that rural Alaska contractors and residents will do only the minimum required by law and concluded that some form of subsidy might be necessary to encourage residents to implement optimal thermal standards. (An alternative to offering economic subsidies would be to modify building codes.) The study did not consider improvements to the existing stock of housing in the calculation of costs and benefits.

All general assumptions and calculations of costs and benefits in the report are included in an appendix to the report. In addition, the estimated costs and benefits of 14 different energy-efficient measures are summarized in a table in the report. The measures with the most potential were shown to be adding insulation, heater retrofits, weatherization, and lighting retrofits. Other measures with noticeable potential include converting or replacing electric appliances.

4.3.1 Lighting

Overview. Potential benefits associated with lighting retrofit projects and efficient lighting in new construction are analyzed in this section. The net present value of lighting retrofit projects is estimated at $23.6 million, and the net present value of increased efficiency in lighting in new construction is estimated at $1.7 million. These results justify the continued study of this measure in the next stage of the Rural Energy Plan.

Analysis. The analysis of potential benefits associated with lighting retrofit projects and efficient lighting in new construction is preceded by a discussion of the theoretical potential of efficient lighting and obstacles to efficient lighting in rural Alaska. The specific analyses for lighting retrofit projects and efficient lighting in new construction are in Subsection 4.3.1.1.

Theoretical Potential

AEA conducted a study in 1990 on the Nikolai Lighting Demonstration project implemented in 1987-1988. The study found that incorporating a systematic, integrated approach to combined demand-side and supply-side conservation would reduce the cost of producing electricity and minimize PCE-eligible kWh consumed, thereby reducing consumer costs and total PCE expenditures. However, the report noted that the cost of alternative lighting fixtures was more than homeowners were willing to pay and many homeowners were not satisfied with the lighting quality of alternative fixtures. The potential of alternative lighting systems to lower electricity costs, together with improvements in lighting technologies and lower prices for alternative fixtures since the Nikolai study was prepared, suggest the need for alternative lighting to be evaluated in more detail.

Table 4-1 summarizes different lighting sources to illustrate the relative value of different types of fixtures. Table 4-2 shows the cost of owning and operating specific types of bulbs for 10,000 hours (the expected life of the compact fluorescent bulb).

A 13-watt compact fluorescent bulb and a 60-watt incandescent bulb have similar light in terms of quality (color) and brightness. However, the cost of owning and operating the bulbs is very different. A self-ballasted, 13-watt, compact fluorescent fixture costs approximately $20 in Anchorage, compared to $0.50 for a standard 60-watt incandescent globe. Still, the compact fluorescent fixture will last 6 to 7 years with 1,500 hours of use per year, and have lower operating costs over that period.

Until recently, fluorescent fixtures did not work with dimmer switches. However, manufacturers claim that new ballasts and lamps such as the Philips Earth Lamp can be used with any controls that work with traditional incandescent lighting. Compact fluorescents that function in three-way switches (such as a 50-100-150 watt incandescent bulb) could not be found to be included in this analysis.

Table 4-1. Comparison of Different Types of Light Sources

Lamp Description	Power (Watts) [a]	Lumens (Brightness)	Durability (Hours) [b]	Capital Cost ($)	Operating Cost per 1,000 Hours ($) [c]
Incandescent Bulb	60	870	1,000	0.50	19.20
Fluorescent Compact Twin	13	825	10,000	9.99	4.16
Fluorescent Compact Quad	26	1,800	10,000	15.99	8.32
Fluorescent Tube (1" X 48 ")	32	3,050	20,000	2.99	10.24

Source: Calculated by Northern Economics using information from *Fine Homebuilding*, Winter 1999 (No. 127), and Fred Meyer stores, October 2000.
[a] Includes ballast wattage for fluorescents
[b] Number of hours a light source is expected to burn
[c] Calculated at 32 cents per kWh

Table 4-2. Total Cost Comparison for Compact Fluorescent and Incandescent Bulbs (10,000 Hours)

Lamp Description	Power (Watts) [a]	Duration (Hours)	No. of Bulbs [b]	Capital Cost ($)	Operating Cost ($) [c]	Total Cost ($)
Incandescent Bulb	60	10,000	10	5.00	192.00	197.00
Fluorescent Compact Twin	13	10,000	1	10.00	41.60	51.60

Source: Calculated by Northern Economics using information from *Fine Homebuilding*, Winter 1999 (No. 127), and Fred Meyer stores.
[a] Includes ballast wattage for fluorescents
[b] Based on expected bulb life of 1,000 hours for incandescent and 10,000 hours for compact fluorescent
[c] Calculated at 32 cents per kWh

Obstacles to Efficient Lighting in Rural Alaska

There appear to be three main obstacles to widespread use of new lighting fixtures and other end-use conservation strategies in rural Alaska.

- Homeowners typically do not conduct a life-cycle cost analysis for light bulbs and may not have the capital or the willingness to pay $10 for a light bulb when traditional bulbs cost $0.50 (not including shipping).
- Limited availability of lighting fixtures in rural areas
- Lack of incentive on the part of rural utilities to assist customers with the purchase of efficient lighting fixtures and other appliances

Manufacturers claim that issues related to differences in color and brightness between incandescent lights and fluorescent lights have been resolved. However, no data could be found on consumer preferences to document whether the public perceives fluorescent and incandescent lights as substitutes for each other. It is possible that differences in color and brightness is another obstacle. (People may prefer light from incandescent bulbs to light from fluorescent bulbs.)

Initial Cost Compared with Total or Life-Cycle Costs

Spending 20 times more for a better light bulb, even when the purchase makes sense, requires a sufficient income stream and good budget planning. Many residents of rural Alaska earn a significant portion of their income in non-cash form, such as through subsistence activities. These individuals may not have sufficient cash income for more expensive lighting fixtures. The 1988 Analysis North report states:

> "Consumers typically avoid paying now when they can pay later, even if it means paying more later. If there exists no easy way to spread out the costs of energy efficiency measures over time, consumers will forgo the investments and tolerate the higher energy costs later. This phenomenon is even more true for low-income people."

The AEA study in Nikolai, as well as experience from weatherization contractors, also suggests that energy-efficient lighting typically costs more than residents are willing to pay, despite the potential savings.

Energy savings from lighting may or may not be readily apparent in a particular electric bill. For example, the addition of a new appliance or more frequent use of other electrical appliances can mask the savings from new lighting systems. Moreover, some consumers may be concerned about breakage and the chance of poor performance with new lighting systems—discounting heavily the future energy savings that can be realized with new lighting systems. Assuming that people like to have obvious reasons for any given purchase, it is reasonable to conclude that the idea of purchasing something like a compact fluorescent light bulb can be troubling. Many of these issues have been addressed by manufacturers (for example, new compact fluorescent bulbs perform better and are more durable than in the past), but residents of rural Alaska may need to be convinced before they will make such purchases in the unaided marketplace. [24]

Limited Availability of Lighting Fixtures

Weatherization contractors said that they have never seen compact fluorescent fixtures for sale in stores in rural Alaska (Lee and others, 2000). Alaska Commercial Company (AC) stores do not carry compact fluorescent fixtures at present and have not carried them in the recent past. Harold Dill, a buyer for heaters at AC stores and, until recently a buyer for light bulbs at AC stores, said that the company does not carry compact fluorescent bulbs because of their poor performance (physical performance, not sales performance). AC is just starting to use traditional fluorescent lighting in their stores, but does not use compact fluorescent bulbs.

Various informal studies have found that energy-efficient products are essentially unavailable in rural Alaska. Residents of rural Alaska often purchase items by mail order or phone orders and typically purchase what is available or on sale. The issue of energy efficiency is usually not a primary factor in buying decisions (*Rural Electric Initiative*, date unknown).

[24] Onsite research by Northern Economics at the Anchorage Home Depot store in October 2000 indicated that several manufacturers produce compact fluorescent bulbs for home use, but none of the manufacturers recommended that the bulbs be used in closed fixtures. This limitation may be a disincentive for use of compact fluorescent bulbs in rural Alaska.

Lack of Incentives

Rural utilities typically have no incentive to assist customers with the purchase of efficient lighting fixtures and other appliances. End-use conservation projects can reduce baseload requirements, but not necessarily peak load. In addition, reductions in kWh demand can make it more difficult for a utility to spread fixed costs.

Energy savings through end-use conservation measures can be viewed as a benefit to customers and to the state (through better load management and reduced PCE expenditures). However, not all utilities recognize lower kWh sales as a benefit because lower kWh sales reduce revenues. For example, if the variable costs of the last kWh sold are $0.10 to $0.20 (the avoided cost figure in the 1988 Analysis North study was $0.125 per kWh, and AVEC statistics show that fuel costs and O&M costs equal $0.18 to $0.21 per kWh[25]) and the retail price for that kWh is $0.32, then the utility loses $0.12 to $0.22 in net revenues if that kWh is not sold due to end-use conservation measures.

Another issue related to incentives is the extent to which the PCE program reduces the incentive that consumers have to implement end-use technologies. In short, if consumers paid the actual cost of power in rural Alaska rather than the subsidized cost, they would have a greater incentive to implement energy conservation measures. From the perspective of the state, this disincentive should be noted. The state is paying to subsidize the cost of each kWh of electricity consumed, thereby encouraging use of more electricity and larger subsidies. The PCE limit of 500 kWh per month for subsidies provides an upper bound, but not necessarily a constraint. For example, AVEC customers without water and sewer may use 150 to 250 kWh per month. Whether or not the addition of water and sewer makes the consumption of electricity by AVEC customers exceed the 500-kWh limit depends on the number and type of appliances they acquire (Petrie, 2000). [26]

Analysis North conducted a study in 1987 titled *The Effect of Electricity Subsidy Programs on the Economic Incentives for Improving Generation and End-Use Technologies*. The analysis showed that the PCE program ranked lower than average among the eight subsidy programs analyzed, for both its effect on a utility's incentive to reduce electrical generation costs and its effect on a customer's incentive to use energy-efficient technologies. The study showed that fixed-cost programs were more effective than PCE in both categories. In these programs, customers receive a fixed amount of monetary credit on their electric bill each month. The amount of the credit is the same for all customers for a given utility, but varies across utilities according to generation costs.

4.3.1.1 Lighting Retrofit Projects and Efficient Lighting in New Construction

Overview. This section describes two lighting efficiency strategies:

- Upgrading lighting systems in existing buildings in rural Alaska. In particular, this strategy involves replacing existing incandescent fixtures with energy efficient fluorescent fixtures (including compact fluorescent fixtures) and upgrading existing fluorescent tube fixtures with new electronic ballasts and other controls. The benefits of this strategy include reduced electricity demand for lighting, thereby lowering the total cost of electricity for end-use customers.

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[25] An AVEC presentation at the Alternative Energy Conference in Fairbanks, Alaska, on August 17, 1999, included the following statistics for kWh generation: Fuel costs equaled $0.09 per kWh and O&M costs equaled $0.09 to $0.12 per kWh. O&M costs included overhauls, tune-ups, inspections, parts, and operator time. O&M costs for diesel engines were $0.11 per kWh. Total costs, with depreciation and interest included, were estimated to be $0.25 to $0.29 per kWh generated.

[26] The addition of an electric tank water heater by itself could make monthly consumption exceed the 500-kWh limit and alter the incentives of the program. However, AVEC customers are encouraged to purchase oil-fired on demand heaters rather than electric heaters (AVEC tariff advice sheet, Item 7.09).

- Installing efficient lighting in new construction in rural Alaska. Efficient lighting systems may have a higher initial cost than alternatives such as incandescent fixtures, but would have a lower life cycle cost. The benefits of this strategy include reduced electricity demand for lighting, thereby lowering the total cost of electricity for end-use customers. Examples in this subsection focus on the residential sector, but the strategy also applies to commercial and institutional buildings.

Analysis. The 1988 Analysis North report references a RurAL CAP survey that was conducted to determine the value of upgrading (in existing homes and other buildings) to efficient lighting in the village of Hooper Bay. Results suggested that it would cost $350 per home to install efficient lighting and that savings would be approximately 750 kWh per home per year.

In the current study, using avoided costs close to $0.15 per kWh, savings of 750 kWh per home per year suggest a savings of approximately $113 per home per year. At $0.32 per kWh (the average retail cost), these figures suggest a savings of $240 per home per year.

Table 4-3 shows the possible savings with installation of efficient lighting. Table 4-3 uses the avoided cost figure because some portion of O&M costs, as well as all capital costs, for generation equipment must be incurred even if the demand for electricity falls with conservation. The retail cost figure is mentioned as a point of reference.

There were an estimated 20,000 PCE homes in 1988—at the time of the Analysis North report. The total value of lighting retrofit projects in Table 4-3 also uses an estimate of 20,000 PCE homes. Many rural residences have installed efficient lighting systems since 1988. However, many new residences have been constructed—many with conventional, incandescent lighting. Table 4-3 includes the assumption that 20,000 homes still have inefficient lighting systems.

Table 4-3. Total Potential Value of Lighting Retrofit Projects in Rural Residences

Value of Electricity ($ per kWh) [a]	Amount per Home ($)				Net Present Value with 20,000 PCE Homes ($) [d]
	Cost of Lighting Upgrade	Annual Savings	Present Value of Costs Over 20 Years [b]	Present Value of Benefits Over 20 Years [c]	
0.15	350	113	503	1,681	23.6 Million

Source: Calculated by Northern Economics based on cost estimates from Analysis North, 1988, and the current cost of electricity (avoided cost of $0.15 per kWh).
Note: It is assumed that 20,000 homes have inefficient lighting systems.
[a] Estimate of avoided cost based on $0.09-0.10 per kWh for fuel and $0.01-0.10 per kWh for O&M
[b] Calculated with 3 percent discount rate and $200 in replacement/repair costs after 10 years (initial cost and replacement cost figures from Analysis North, 1988).
[c] Calculated with 3 percent discount rate
[d] Present value of savings minus present value of costs for 20,000 homes

The estimated annual savings of $113 per year for an initial investment of $350 suggests a rate of return of 32 percent. Rebuild America building audits show lighting retrofit projects with equal or higher rates of return in institutional buildings. For example, the Rebuild America audit for Craig High School (Craig, Alaska) shows that replacing the mercury vapor lights with two-lamp fluorescent fixtures with electronic ballasts and T8 lamps would provide better lighting at about half the electrical load. The audit also shows that this retrofit would cost approximately $1,170 and provide savings of approximately $400 per year (2,500 kWh per year at $0.16 per kWh avoided cost). This project has an annual return of 34 percent and estimated simple payback of 3 years. Smaller projects recommended for Craig High School offer higher returns.

In addition to retrofit projects in existing structures, savings can be realized with installation of efficient lighting in new construction. Newer buildings in rural Alaska are using more fluorescent lighting, but the potential remains for additional efficiency improvements and savings. A buyer for Alaska Commercial (AC) Company Value Center stores,[27] said that newer AC stores have fluorescent lighting while older stores do not, and explained that fluorescent lighting was not installed in older stores due to concerns about performance of the lights in cold buildings. The fluorescent lighting being installed in the new stores includes ceiling fixtures (for example, 4-foot and 8-foot tubes), but not compact fluorescent fixtures in display areas (Dill, 2000).

The 1998 Analysis North Report includes an estimate of the incremental cost and potential value of improving the efficiency of lighting in new construction. In that report, it was assumed that the energy load from new homes could be reduced by 500 kWh per year for a cost of $250. (At $0.15 per kWh, the energy savings corresponds to a savings of $75 per year. This ongoing, annual savings is compared to the one-time expense of $250.) The report assumed that 500 new homes would be constructed each year and used a 40-year planning horizon, with benefits escalating at 1 percent per year to account for real increases in the cost of electricity. More modest assumptions are used here to allow for the possibility that a higher percentage of the newer homes will include efficient lighting and that electricity costs may be more stable. The shorter planning horizon allows for the chance that homes may be renovated after 20 years.

Table 4-4 shows the potential value of lighting upgrades in new rural residences.

Table 4-4. Potential Value of Lighting Upgrades in New Rural Residences

Value of Electricity ($ per kWh) [a]	Amount per Home ($)				Net Present Value with 100 New Homes ($) [d]
	Cost of Lighting Upgrade	Annual Savings	Present Value of Costs Over 20 Years [b]	Present Value of Benefits Over 20 Years [c]	
0.15	250	75	442	1,116	1.7 Million

Source: Calculated by Northern Economics based on cost estimates from Analysis North, 1988, and the current cost of electricity (avoided cost of $0.15 per kWh).

[a] Estimate of avoided cost based on $0.09-0.10 per kWh for fuel and $0.01-0.10 per kWh for O&M.

[b] Calculated with 3 percent discount rate and $250 in replacement/repair costs after 10 years (initial cost and replacement cost figures from Analysis North, 1988).

[c] Calculated with 3 percent discount rate

[d] Net present value of savings with 100 new homes constructed each year for 20 years (net present value of each home always based on 20-year planning horizon, regardless of when constructed)

Conclusions. The potential benefits associated with lighting retrofit projects and efficient lighting in new construction justify the continued study of this measure in the next stage of the Rural Energy Plan. The net present value of lighting retrofit projects is estimated to be $23.6 million and the net present value of increased efficiency in lighting in new construction is estimated to be $1.7 million.

A different perspective can be used to demonstrate that end-use conservation has the potential to reduce the cost of electricity in rural Alaska. For example, the 1998 Analysis North report suggests that $250 in lighting upgrades (in new construction) would result in annual energy savings of 500 kWh. With a planning horizon of 10 years, these assumptions suggest an average annual cost of $25 ($250 divided by 10) and an average annual savings of 500 kWh, or $0.05 per kWh saved. In this case, a kWh saved is much less expensive than a kWh purchased for use.

[27] Alaska's largest rural retailer of groceries and general merchandise

4.3.2 Water Heaters

Overview. This subsection provides an introductory discussion regarding energy use by electric water heaters. A more detailed discussion is provided in Section 7, along with an analysis of the potential savings with alternative strategies for water heating.

Analysis. The top-rated electric water heaters require 4,624 kWh per year for average levels of use (American Council for an Energy Efficient Economy [ACEEE], 2000). The 1988 report from Analysis North assumes that water heaters in rural Alaska use approximately 4,800 kWh per year. Water heaters have not been present in many homes in the past due to the lack of public water and sewer service. As a result, many electric water heaters are relatively new and the benefit of replacing these uses would not be substantial. However, in addition to the issue of kWh per year or dollars per year for consumers, system load or energy demand placed on rural utilities should be considered.

AVEC provides tariff advice to member utilities that reads:

> "The Utility does not recommend electric water heaters, electric space heating appliances, electric dryers (especially commercial), electric saunas, or other similar devices whose main purpose is to produce heat electrically in the Utility service areas, since cost comparisons with alternate methods are generally unfavorable and, in some cases, cause detrimental effects to the Utility system."

This advice became effective in November 1977. More recently, AVEC wrote a letter in March 2000 to the Alaska Department for an Environmental Conservation (ADEC) Village Safe Water (VSW) Program about alternatives to electric hot water heaters. In the letter, AVEC requested that VSW consider and recommend oil-fired rather than electric hot water heaters. The letter also highlighted Toyotomi and Monitor brand high-efficiency, direct-vent, oil-fired units (Petrie, 2000).

Several reports have shown that heating domestic water with electricity is less efficient (requires more energy or fuel) and, as a result, substantially more expensive, than heating water with oil. The benefits of fuel switching are discussed in Section 7.

Conclusion. As homes have become more energy-efficient with the addition of more insulation and better construction techniques, space heating demands have fallen considerably. In some cases, energy demand for space heating is less than energy demand for water heating. In these cases, it is possible that domestic hot water tanks could be used as space heating devices to reduce the total cost of space and water heating. This strategy is discussed in Section 7. Other strategies related to water heating, including the use of low-flow showerheads, are also discussed in Section 7.

4.3.3 Other Appliances

Overview. This subsection provides estimates of the value of implementing strategies to reduce the cost of electricity associated with other appliances. Appliances considered include refrigerator-freezers and televisions. The net present value of replacing existing refrigerator-freezers with energy-efficient models (as the existing models need to be replaced) is estimated to be $8.3 million and the net present value of replacing existing televisions with energy efficient models (also as the existing models would be naturally replaced) is estimated to be $2.3 million. The potential benefits justify continued study of this measure in the next stage of the Rural Energy Plan.

Analysis. The ACEEE website states, "A typical new refrigerator with automatic defrost and a top-mounted freezer uses less than 650 kWh per year, whereas the typical model sold in 1973 used nearly 2,000 kWh per year." If refrigerator-freezer units in rural Alaska use 1,250 kWh per year[28]—assuming that the average unit in rural Alaska is 40 percent more efficient than the typical model sold in 1973—then the benefit of replacing those appliances would be approximately $90 per year in reduced energy costs (at $0.15 per kWh avoided cost). If a refrigerator-freezer unit is expected to last 15 years, the present value of energy savings would be roughly $1,075 (with a 3 percent discount rate). A resident of rural Alaska would need to be able to purchase an energy-efficient unit for less than $1,075 to be able to justify the purchase based on the value of the energy savings. However, if a new refrigerator or refrigerator-freezer is to be purchased anyway, then the relevant cost figure is the difference between the cost of an ordinary model and an energy-efficient model.

A 16-cubic-foot, energy-efficient refrigerator-freezer sold by General Electric, Roper, or Maytag (different brands may be made by the same manufacturer) costs $1,000 to $1,400, compared to $600 to $1,000 for a less efficient model (Allen and Peterson, 2000; Costco, 2000). Based on these figures, the incremental cost of an energy-efficient refrigerator-freezer is $400 (the difference in the averages of $1,200 and $800 for the two types of models). Assuming that 15,000 PCE homes have refrigerators or combination units with expected life of 15 years, 1,000 units might be replaced each year. Table 4-5 summarizes the value of replacing older units with newer, more energy-efficient models.

Table 4-5. Potential Value of Upgrading Refrigerator-Freezer Units

Year	No. of Units Purchased	Incremental Cost ($) [a]	Annual Savings ($ per Unit) [b]	Present Value of Savings ($ per Unit)	Net Present Value of Savings ($) [c]
1	1,000	400	90	1,074	674,000
2	1,000	400	90	1,043	654,000
3	1,000	400	90	1,012	635,000
Each Ensuing Year	1,000	400	90		
Total After 15 Years	**15,000**				**$8.3 Million**

Source: Calculated by Northern Economics with cost estimates and energy usage figures from manufacturers.
[a] Cost of energy-efficient, 16 cubic-foot refrigerator-freezer in Anchorage (Allen & Peterson, 2000) compared to ordinary model (Costco, 2000)
[b] Assumes that existing average unit uses 1,250 kWh per year, new unit would use 650 kWh per year, and avoided cost is $0.15 per kWh
[c] Present value of savings minus one-time incremental cost; calculated with 3 percent discount rate and takes into account the value of all 1,000 units replaced each year

Another electrical appliance that receives a significant amount of use in rural Alaska and where newer models offer significant energy savings is televisions. The 1988 report from Analysis North suggests that typical color televisions in use require about 130 watts, compared to 60 watts for the most efficient models. If a television is on for 8 hours per day, the net savings of 70 watts translates into 204 kWh per year (Analysis North, 1988).

At $0.15 per kWh, a savings of 204 kWh per year equals a savings of approximately $31 per year. The present value of saving $31 per year for 10 years (the assumed life of a television) is $264. If there are 10,000 PCE homes with televisions that operate 8 hours per day, then the total potential savings generated by replacing those televisions would be $2.64 million. If new, energy-efficient televisions are purchased when older sets need to be replaced, then the incremental cost is effectively zero

[28] The estimated value of replacing the existing stock of refrigerators and freezers in rural Alaska presented in the 1988 Analysis North report assumed that the existing stock used 1,500 kWh per year. The estimate of 1,250 kWh per year used in the current study allows for the addition of more efficient units to the stock.

dollars because energy-efficient models do not cost more than other models. Assuming that there are 10,000 televisions in rural Alaska (the actual number may be higher) and the average life of a television set is 10 years, then 1,000 sets might be replaced each year. Table 4-6 shows the value of replacing older television sets with more energy-efficient models at a rate of 1,000 sets per year.

Table 4-6. Potential Value of Upgrading Televisions

Year	No. of Units Purchased	Incremental Cost ($) [a]	Annual Savings ($ per Unit) [b]	Net Present Value of Savings ($) [a]
1	1,000	0	204	264,000
2	1,000	0	204	256,311
3	1,000	0	204	248,845
Each Ensuing Year	1,000	0	204	
Total After 15 Years	**15,000**			**$2.3 Million**

Source: Calculated by Northern Economics based on cost estimates from Analysis North, 1988, and the current cost of electricity (avoided cost of $0.15 per kWh).
Note: Assumes that there are 10,000 televisions in rural Alaska, the average life of a television set is 10 years, and 1,000 sets might be replaced each year
[a] Cost and benefit figures in columns 3 and 4 are taken from the 1988 Analysis North report.
[b] Calculated using a discount rate of 3.0 percent and a planning horizon of 10 years.

As with lighting systems, the potential value of energy-efficient appliances suggests that more such appliances should be in place in rural Alaska than appear to be (based on personal observations and comments from weatherization contractors). The reasons why use of energy-efficient appliances is less than optimal are likely complex, but almost certainly involve two major factors—differences in individual and aggregate benefits, and limited availability of energy-efficient appliances.

The aggregate potential net benefits of replacing refrigerator-freezer units and televisions ($8.3 million and $2.32 million, respectively) are significant. However, the benefits to be realized by the individual consumer in any given year are not significant. The average consumer would expect benefits of $90 per year with a more energy-efficient refrigerator-freezer and only $31 per year with a more energy-efficient television. These amounts may not be large enough to make someone take the time and effort needed to find the most energy-efficient model.

Rural Alaskans may purchase appliances while traveling to Fairbanks or Anchorage, or through catalogs. However, most stores such as Costco, Sam's Club, and many catalog stores carry competitively priced appliances that are not energy-efficient. The more energy-efficient appliances tend to be more expensive. Consumers concerned with first cost or initial capital costs may not be able to purchase energy-efficient appliances, even if they are aware of the benefits.

Other technologies or strategies that focus on reducing the cost of electricity in rural Alaska include converting electric cooktops to propane. The 1988 Analysis North report analyzed this strategy and found that significant savings were possible. For example, the report estimated that the total potential net benefit of converting electric cooktops in rural Alaska to propane is $10 million. However, this figure was based on numerous assumptions related to the life expectancy of diesel generators, efficiency of generators at peak and off-peak load, the cost and availability of propane, and other factors that cannot be corroborated at this time.

Conclusions. The potential benefits associated with installation of energy-efficient appliances in rural Alaska justify continued study of this measure in the next stage of the Rural Energy Plan. The net present value of replacing existing refrigerator-freezers with energy-efficient models (as the existing models need to be replaced) is estimated to be $8.3 million and the net present value of replacing existing televisions with energy-efficient models (also as the existing models need to be replaced) is estimated to be $2.3 million.

These savings may be viewed from a different perspective to show that end-use conservation has the potential to reduce the cost of electricity in rural Alaska. For example, Table 4-5 shows that $400 in refrigerator-freezer upgrades would result in annual energy savings of 600 kWh. With a planning horizon of 10 years, these figures suggest an average annual cost of $40, for an average annual savings of 600 kWh, or $0.07 per kWh saved. A kWh saved is much less expensive than a kWh purchased.

4.4 Conclusions and Recommendations

Further research in the area of end-use conservation is justified based on the potential savings. Estimates of the potential net present value of benefits from new lighting systems, appliance upgrades, and other measures presented in this subsection exceed $34 million. Table 4-7 summarizes the total net present value of different measures as demonstrated in this section. Presented another way, the potential benefits associated with end-use conservation can be shown to effectively reduce the cost of electricity in rural Alaska. Table 4-8 shows that the cost per kWh saved from different end-use conservation measures (using the figures shown in Table 4-4 and Table 4-5) is significantly less than the cost of additional electricity. That is, it is significantly less expensive to buy a kWh of savings than purchase a new kWh for some end use.

Table 4-7. Summary of Potential Savings with End-Use Conservation Strategies

Item	Total Net Present Value ($Millions)	Location of Additional Information
Installation of Energy Efficient Lighting in Existing Residences	23.60	Table 4-3
Installation of Energy Efficient Lighting in New Residences	1.70	Table 4-4
Refrigerator-Freezer Upgrades	8.30	Table 4-5
Television Upgrades	2.32	Table 4-6

Table 4-8. Examples of Cost per kWh Saved with Lighting and Appliance Upgrades

Area	Action	Cost of Action ($)	Average Annual Cost over 10 Years ($)	Annual Energy Savings (kWh)	Cost per kWh Saved ($ per kWh)
Lighting	Upgrades in New Construction	250	25	500	0.05
Appliances	Refrigerator/Freezer Upgrades	400	40	600	0.07

If possible, case studies should be conducted to improve overall understanding of how many homes and institutional buildings in rural Alaska use efficient lighting systems, heaters, and appliances. Case studies could include survey questions to improve understanding of obstacles to implementing end-use technologies. Future studies also should include data collection on the cost of producing electricity at the margin, an analysis of the impact of end-use conservation measures on utilities, and an analysis of the impact of end-use conservation programs on other factors such as fuel storage costs.

5 Alternative Energy

5.1 Introduction

Summary

This section focuses on alternatives to diesel power generation and other technologies that could be implemented to reduce the cost of electricity in rural Alaska. This preliminary analysis indicated that:

- Very few alternative technologies have the potential to be competitive with diesel power in rural Alaska. The only issue recommended for further study relates to single wire ground return interties.
- Additional research needed in the areas of energy storage systems and wind power is being conducted as part of other research efforts. No additional work is needed as part of the Rural Energy Plan.
- Technologies such as microturbines could be monitored. These technologies could be competitive with diesel power as the costs of the technologies decline in the future. No additional research is needed for these technologies as part of the Rural Energy Plan.

This section provides summaries and brief analyses of various alternative technologies that possibly could reduce the cost of electricity in rural Alaska. Each technology is discussed in a separate subsection, with an analysis and set of recommendations regarding further study.

5.2 Existing Conditions

Existing conditions for alternative technologies vary considerably depending on the technology. For example, there is considerable experience and data for wind energy systems in rural Alaska, but very little for tidal power or geothermal systems. As a result, existing conditions in rural Alaska for the different alternative technologies covered in this section are summarized in the relevant subsection.

Economic assumptions, including a real discount rate of 3 percent and a fuel cost of $1.00 per gallon, were introduced earlier. Additional economic assumptions, such as the installed cost of diesel systems ($1,000 per kW), are presented in the subsections that follow.

5.3 Analysis of Strategies

5.3.1 Natural Gas/Coal Bed Methane

Overview. This screening analysis reinforces findings presented in a February 1997 analysis for DCRA by Mark A. Foster Associates (MAFA) titled *The Rural Alaska Natural Gas Study – A Profile of Natural Gas Energy Substitution in Rural Alaska, Final Report*. That report shows that a natural gas-fired resource would be economically viable only if the fuel were less expensive than diesel on a dollars-per-Btu basis. Because this condition is not found in rural Alaska and is not expected to occur in the near future, this strategy is not recommended for further study.

Natural gas is abundant in parts of Alaska and often mentioned in the news with discussions of a potential gas pipeline to transport natural gas from the North Slope to markets in urban areas, the Lower 48 states, and other countries. The following text provides an analysis of the potential for natural gas to reduce the cost of electricity in rural Alaska.

Although natural gas has played an important role in both energy production and domestic heating in Alaska, the locations of producing reservoirs have limited the use of natural gas to a relatively confined area. The principal locations of the predominant natural gas reserves in the state are in Cook Inlet and the North Slope, with Cook Inlet gas being used the most.[29]

Even if a community is close to producing reservoirs, gas may not be available to residents of that community. For example, the City of Homer is relatively close to the Cook Inlet gas fields as well as a smaller, non-developed gas reservoir north of the city. Enstar Natural Gas has the distribution rights for the area, but currently considers it uneconomic to extend its pipeline system to Homer because of the relatively small size and low density of heating loads. Therefore, it appears that only in areas with large population centers close to reservoirs would expected revenues support the capital costs of the pipeline system required for transportation and distribution.

There are, however, other sources of natural gas throughout the state, although in smaller concentrations than Cook Inlet and the North Slope. In addition, there are related resources such as coal-bed methane[30] (natural gas found in coal deposits) found in various areas throughout the state.

Analysis. Generating resources can use a variety of fuels, with the more common being natural gas and diesel (sometimes referred to as fuel oil or liquid fuel). Even without the cost of fuel being considered, fuel type affects the per-unit operating costs of a generating resource. The following items illustrate this point, assuming that the power facility is a small generating resource (less than 2 to 3 megawatts [MW]).

Comparison of Effects on Operating Costs for Natural Gas and Diesel Fuel Power Facilities

- The installed cost of a unit using natural gas is 2 to 3 times that of a diesel-fueled generator.
- Operating costs are approximately the same, although units using natural gas rather than diesel fuel are more susceptible to fuel quality problems.
- Fuel efficiency in Btu per kWh is similar for natural gas and diesel fuel.
- Nitrous oxides (NO_x) and particulate emissions are reduced significantly when natural gas is used rather than diesel fuel, but carbon monoxide emissions are slightly higher.

Given the large differential in capital costs and similar generating efficiency (Btu per kWh), the only way that a natural gas-fueled resource would be more economic than a diesel-fueled resource is if the fuel were less expensive than diesel on the basis of dollars per Btu.

The 1997 MAFA analysis for DCRA assessed the conditions under which natural gas would be an attractive energy alternative in rural Alaska.[31] The analysis found that under base case assumptions, the cost of diesel-fueled resources was equal to or less than the cost of natural gas-fueled resources for the entire range of community sizes investigated. Table 5-1 shows the cost of natural gas compared to diesel as presented in the report.

[29] Gas transmission systems (pipelines) are capital-intensive, and only a limited portion of the Railbelt region can use gas for domestic heating. Electric interties, however, enable the entire Railbelt to benefit from large generating plants that use natural gas fuel. North Slope gas is predominantly reinjected to increase oil production, although the North Slope Borough uses some for energy production.

[30] During the coal formation process, a number of other products are formed and stored within the coal. Under the right circumstances, one of these products, methane gas, is absorbed on the internal surfaces of the coal and stored until it is released later. This methane gas, commonly referred to as coal-bed methane, is natural gas found in coal deposits.

[31] MAFA, 1997.

A number of alternative scenarios were included in the MAFA analysis to test the sensitivity of the results to differing assumptions. These alternative scenarios are also provided in Table 5-1. The results show that only under very favorable assumptions is development of a natural gas (or coal bed methane) field economically competitive with diesel energy in rural Alaska.

Table 5-1. Relative Cost of Gas Energy Compared to Diesel, 1997

Scenario	Relative Cost of Gas Energy Compared to Diesel [a] by Community Size in Number of Residents ($)				
	Large (3,500)	Med. (2,000)	L-Small (500)	M-Small (350)	S-Small (250)
Base Case (Diesel) [a]	1.04	1.00	1.40	2.23	3.37
$1 million gas exploration costs	1.07	1.04	1.53	2.54	3.88
$7 million gas exploration costs	1.25	1.30	2.35	4.40	6.94
Base diesel price + 25 cents per gallon	0.88	0.85	1.27	2.03	3.09
Base diesel price + 50 cents per gallon	0.77	0.75	1.16	1.87	2.85
2 miles to gas field	1.05	1.00	1.43	2.29	3.48
30 miles to gas field	1.20	1.23	2.11	3.85	6.04
$1 million exploration costs, 15 miles to gas field, 25 cents per gallon fuel increase	0.98	0.99	1.72	3.07	4.81
$3 million exploration costs, 2 miles to gas field, high-quality gas field	0.97	0.99	1.66	3.24	5.04

Source: MAFA,1997.

[a] The base case included a number of assumptions detailed in the report, but several of the more noteworthy assumptions include the following:

1. The village was on top of or adjacent to the natural gas field.
2. Exploration costs were $5 million.
3. Well depth was 3,000 feet.
4. Gas reserves were 1.4 billion cubic feet per well.
5. Three to 11 initial wells and 1 to 9 additional wells were required, depending on the assumed village size.

[a] Diesel Case = 1.00

Conclusions. This screening analysis did not reveal new evidence that suggests that development of natural gas resources would provide significant benefits to residents of rural Alaska. The analysis reinforces findings in Foster, 1997. That report shows that the only way for a natural gas-fired resource to be economically viable is if the fuel were less expensive than diesel on a dollars-per-Btu basis. This condition is not present in rural Alaska and not expected to occur in the near future. As a result, this strategy is not recommended for further study.

5.3.2 Energy Storage Systems

Overview. Energy storage systems (ESSs)—battery energy storage systems (BESSs) in particular—appear to have the potential to reduce the cost of electricity in rural Alaska. More research is needed to determine the overall net benefits that could be expected from battery systems in rural Alaska. This additional research is not recommended as part of the Rural Energy Plan as it is part of the work being conducted by the U.S. Department of Energy, AVEC, Chugach Electric Association, and AEA on battery systems in Alaska. As a result, this strategy is not recommended for further study in the Rural Energy Plan.

ESSs are resources that can provide energy at times when other forms of power are not available or need to be conserved. Since these systems must be recharged, they typically are used as a form of capacity with limited amounts of energy. Another, less common, use is to improve power quality (frequency and voltage). The most common ESS system is the BESS. Others may include flywheels and capacitor banks, but these have very limited applications. The following discussion therefore reviews the merits of battery systems.

In Alaska, the only utility setting of a BESS is at Metlakatla Power & Light, although Golden Valley Electric Association (GVEA) is pursuing installation of a BESS for spinning reserves. Additionally, AVEC, Chugach Electric Association, and AEA are investigating the merits of a BESS on a limited basis in conjunction with the U.S. Department of Energy office in Albuquerque, New Mexico.

Analysis. The BESS is composed of a set of batteries, charging and inverting equipment, and a primary source of power generation. At times when the batteries are not in use, excess power from the primary source of power generation is converted to direct current (DC) for battery charging or maintenance of full charge. When energy from the BESS is required, DC power passes through an inverter, and alternating current (AC) power is then supplied into the system. This round-trip through the converting, storage, and inverting processes can result in losses up to 30 percent.

As a source of capacity, BESS can be used in the following applications.

- **As a supplemental source of power for hydroelectric, wind, tidal, or solar installations**. During the times that energy from these sources is not available or generation is less than load, the BESS can be used as a supplement to forego the operation of a diesel unit. The BESS can be recharged when production levels from the primary resources are greater than load.
- **As a supplement to a small diesel generator to eliminate the need for a larger generator.** Generating efficiency decreases as unit output decreases, and generating resources sized to meet peak loads may be very inefficient to use during off-peak periods. If a smaller resource can be used during off-peak periods and supplemented with a BESS during peak periods, fuel efficiency may, under the right circumstances, be increased. BESS recharging would be accomplished during off-peak periods when generating capacity is greater than load requirements. However, many newer diesel generators have a much flatter fuel efficiency curve. For these units, efficiency does not decrease steeply, except at very low output levels.[32] Furthermore, automatic switchgear and other equipment can dispatch the most efficient unit for the given load to increase fuel efficiency.
- **As a means to solve power quality problems, BESS can be used to respond to large loads suddenly placed on a system**. Hydroelectric generators, wind turbines, and certain diesel generators cannot respond quickly to such fluctuations, and voltage and frequency degradation can occur. The use of a BESS can eliminate the need to have a diesel generator online that is being used simply to respond to these large fluctuations in power requirements.

At the time of the Metlakatla Power & Light installation, the utility's peak load was approximately 3.5 MW, nearly one-third of which was from a sawmill. Metlakatla Power & Light hydroelectric resources could provide for sufficient capacity under most water conditions, but lacked response speed to meet the large swings in active and reactive power requirements caused by the sawmill. Therefore, a diesel unit had to be run at low loads to maintain proper frequency and voltage; and even at these low loadings, water was spilled at the hydroelectric sites. Furthermore, the low unit loading of the diesel resource represented a loading with poor fuel efficiency.

[32] Information was requested from Detroit Diesel, Cummins, and other manufacturers to determine whether the flatter efficiency curves advertised by some manufacturers are common for a majority of the diesel generator sets or unique to one or two models. Information was not provided at the time this report was printed.

Metlakatla Power & Light secured sufficient grants to design and install a BESS that would eliminate the need for the diesel. Unfortunately, the sawmill was closed, and the main problem that the BESS was designed to address therefore was no longer a factor.

The size of a BESS depends on the amount of energy required when in use and the availability of re-charging power. Resource economics, in turn, are dependent on a number of factors including the following.

- Number of batteries included in the BESS
- Cost of installation
- Price of fuel
- Cost of re-charging energy
- Amount displaced fuel
- Load characteristics

At this time, lead-acid batteries are economic, but their weight per unit of volume is very high. Consequently, transportation costs are very high. Because batteries must be properly disposed of at the end of their lives, transportation costs may include both transportation to and from the site.

Conclusions. It is difficult—if not impossible—to analyze the economic potential of battery systems in general due to the specificity of data required. For example, the potential benefits of a BESS at a rural utility would depend on daily and seasonal load curves, the efficiency of generating equipment used to meet the loads, and other generators available for dispatch. These factors vary significantly from village to village, making a summary analysis or single case study inappropriate for determining whether battery systems have significant potential to reduce the cost of electricity in rural Alaska.

In the absence of extensive load and generation data from rural communities, no definitive conclusion about the potential benefits of BESS can be reached. Additional study is needed to collect data, to prepare case studies, or to develop a broad enough general model to test a variety of parameters. However, such additional study is underway. The analysis being conducted by the U.S. Department of Energy with Chugach Electric Association, AVEC, and AEA includes a model to determine the potential benefits of load leveling with diesel generating systems. Staff at AEA believe that this model will be field-tested at a site in rural Alaska (Crimp, 2000).

While more research is needed to determine the overall net benefits that could be expected from battery systems in rural Alaska, this additional research is not recommended as part of the Rural Energy Plan at this time. The research that is needed is part of the work being conducted by the U.S. Department of Energy, AVEC, Chugach Electric Association, and AEA on battery systems in Alaska.

5.3.3 Fuel Cells

Overview. Fuel cells offer the promise of clean energy and sometimes are described as being "the future of energy." However, capital costs and fuel requirements make it difficult to find an economically viable application in rural Alaska at this time. Even if an appropriate fuel such as propane were available at a price equivalent to the price of diesel, the high capital cost of fuel cells would make electricity from a cell twice as expensive as electricity from a diesel generating unit.

Similar to a battery, a fuel cell produces power through chemical reactions. Unlike batteries, however, fuel cells produce electric power as long as fuel is available. The following text provides an analysis of the potential for fuel cells to reduce the cost of electricity in rural Alaska.

There are no fuel cells in operation in rural Alaska at this time, although several have been considered. Limited fuel supplies and concerns about reliability have prevented most utilities in rural

Alaska from seriously considering fuel cell installations, even though the cells offer the potential for clean power in the right setting

In the Anchorage area in the 1980s, a fuel cell was installed at Elmendorf Air Force Base and operated for a period of time. Data were not readily available to analyze the economics or to determine the operating success of this unit. In the late 1990s, two ONSI Corporation units were installed at the National Guard Armory. These units provide power to the Armory, and excess power is fed into Fort Richardson.

In summer 2000, Chugach Electric Association installed five 200-kW ONSI units at the Ted Stevens Anchorage International Airport. Design, fabrication, and other related costs were more than $5 million (before rebates, grants, and other subsidies), and installation costs were approximately $1.1 million. The units have not been declared commercially operable, and therefore detailed observations on operating efficiencies or maintenance activities cannot be made.

The village of Nuiqsut in the North Slope Borough is pursuing development of a fuel cell. However, the fuel cell that the borough is investigating is a dual-fuel type that can use fuel oil as well as natural gas. Since this type of unit is still experimental, the cost is very high. A preliminary cost estimate is $10 million for a 250-kW unit, and the village is seeking grants to fund acquisition and installation. The unit will not be ordered until such grants are available.

Analysis. There are seven types of fuel cells available at this time, with each type offering specific advantages over others. However, models in current operation (not experimental) require clean, hydrogen-rich fuel such as natural gas or propane.[33] The hydrogen reacts with oxygen in the atmosphere to produce electricity, and heat and water are the primary by-products. The amount of heat and water emitted per unit of fuel depends on the type of fuel cell. Very small amounts of hydrocarbons and carbon monoxide are emitted.

Fuel cells have been and still are used in the space program, but commercial applications are very limited. To date, only one company, ONSI Corporation, sells a commercial fuel cell plant. The ONSI fuel cell is the 200-kW PC25 model of the phosphoric acid type. ONSI and others are conducting research on other types, sizes, and a variety of applications including transportation and home uses.

The ONSI unit includes three major subsystems:

- **Fuel Processing System**—Fuel is converted into a hydrogen-rich stream through a catalytic reaction. Carbon monoxide is converted into carbon dioxide.
- **Cell Stack Assembly**—The hydrogen and oxygen combine electrochemically to produce electric power and heat. Exhaust is water vapor and carbon dioxide, and steam that is produced is returned to the fuel processing system.
- **Power Conversion System**—DC power output is converted to AC power.

Fuel efficiency is approximately 10,000 Btu per kWh. This rate compares to efficiencies of diesel-fueled internal combustion resources ranging from approximately 14,000 Btu per kWh (10 kWh per gallon) to 10,000 Btu per kWh (14 kWh per gallon).

In general, fuel cell technology offers a number of advantages in power generation. These include very low exhaust emissions, quiet operations, usable by-products (heat and water), and absence of

[33] In some fuel cells, hydrogen-rich fuels such as natural gas are converted or "reformed" to hydrogen, and hydrogen is the actual fuel used in the cell. Efficiencies and byproducts can change with this conversion and depending on whether this conversion is included in various calculations. For example, reforming natural gas to release the hydrogen results in emissions of carbon dioxide.

moving parts. However, a number of disadvantages also exist that, unless changes are made, will severely limit applicability in rural Alaska. These disadvantages include high capital costs, the requirement for clean, hydrogen-rich fuels, and intricate systems, the failure of which can severely damage the fuel cell system.

The fuel processing system is a critical component of the overall system. If filtration is inadequate and fuel contains impurities (including small amounts of sulfur), stacks can be severely damaged. Furthermore, an uncontrolled shutdown in fuel supply can also damage the fuel cell system.

Since the commercial application of fuel cells is still in its infancy, detailed operating cost estimates are not available. However, preliminary cost and performance data are available from ONSI and Chugach Electric Association. These data permit a comparison of diesel and fuel cell systems. Table 5-2 is a summary of fuel cell costs and provides a cost comparison between fuel cells and a new diesel generator. Although the efficiency and maintenance costs of the diesel generator vary by unit type and average loadings, the table shows that the expected costs of the fuel cell are more than twice that of a diesel generator. For the two resources to be priced comparably, capital costs of the fuel cell would have to be eliminated.

Table 5-2. Fuel Cell Costs for a 200-kW Propane Unit Generating 876 MWh per Year

	Costs ($)
Capital Costs	
Fuel Cell	1,000,000
Installation Costs	250,000
Fuel Storage (30,000 gallons) [a]	40,000
Total	**1,290,000**
Annual Costs	
Capital Costs [b]	131,400
Annual Maintenance Costs	25,000
Fuel [c]	95,400 – 378,700
Total	**251,800 – 535,000**
Cost Summary (Cost per kWh)	
Non-Fuel	0.18
Fuel	0.11 – 0.43
Total	**0.29 – 0.61**

Source: Calculated by Financial Engineering using data from Chugach Electric Association and ONSI, 2000.

[a] Assumes 50 percent plant factor

[b] Based on 20-year amortization at 8 percent interest

[c] Based on fuel consumption of 10,000 Btu per kWh, a propane energy content of 91,838 Btu per gallon, and delivered propane costs of $1 per gallon (Gustavus) and $3.97 per gallon (Nome). Fuel distributors said that bulk fuel deliveries were possible, but such deliveries have not occurred. Therefore, fuel prices should be viewed as uncertain.

Table 5-3. Cost Comparison of Fuel Cells and Diesel Generators

Item	Cost ($)	
	ONSI Fuel Cell [a]	Diesel Generator
Capital Cost		
	2,580,000 [b]	240,000 [c]
Annual Unit Costs ($ per kWh): [d]		
Amortized Capital Costs	0.150	0.014
Maintenance Costs	0.029	0.05
Fuel Costs	0.11 – 0.43 [e]	0.083 [f]
Total Annual Costs	**0.29 – 0.61**	**0.15**

[a] Fuel cell assumptions are in Table 5-2.
[b] Total installed cost for two 200 kW fuel cells ($1,290,000 each, as shown in Table 5-2) for a total of 400 kW.
[c] Estimate from EPS for a 400-kW unit (according to AVEC, costs are $1,000 per kW with fuel storage)
[d] Assumes 400-kW operating at a 50 percent plant factor. Amortization with 8 percent over 20 years.
[e] Based on $1 to $3.97 per gallon.
[f] Based on $1 per gallon at a generating efficiency of 12 kWh per gallon.

Diesel maintenance costs in Table 5-3 are taken from AVEC data.[34] The AVEC data show that fuel costs are approximately $0.09 per kWh and other non-fuel O&M costs range from $0.09 to $0.12 per kWh generated. The cost estimate of approximately $0.15 per kWh shown in Table 5-3 includes consideration for O&M costs such as filters, oil, tune-ups, and overhauls, but not inspections, personnel, and space costs. These latter costs are not included because they would be incurred regardless of the generating system in use.

Conclusions. The high capital cost of fuel cells, along with limited supply of suitable fuel in rural Alaska, suggest that fuel cells do not need to be considered for further study.

Fuel distributors deliver propane to many villages in rural Alaska, but deliveries are typically made in 20- to100-gallon canisters rather than in bulk.[35] The analysis suggests that even if propane or other fuel for fuel cells were available in rural Alaska at a price competitive with diesel (for example, $1 per gallon), the cost of electricity from fuel cells would still be twice the cost of electricity from diesel generator sets because of the capital costs for fuel cells. In addition, concerns about fuel quality and other uncertainties suggest that applications in remote settings would be premature at this time.

5.3.4 Geothermal Energy

Overview. Geothermal energy is energy from the heat of the earth's core that can be tapped and used to generate electricity. The potential sites in rural Alaska are very limited where the resource is accessible, the demand for electricity sufficiently large, and conditions stable enough for a long planning horizon. This strategy does not meet the criteria to be recommended for further study.

The following text provides an analysis of the potential for geothermal energy to reduce the cost of electricity in rural Alaska.

[34] DOE Renewable Energy Conference, August 17-18, 1999, Fairbanks, Alaska.

[35] Margaret Koeziena of Bonanza Fuel in Nome said that the company typically delivers propane in 100-gallon bottles, at $3.97 per gallon. A fuel distributor in Juneau quoted a price of $1 per gallon to Gustavus, assuming that deliveries were in large quantities.

Geothermal energy is energy from the heat of the earth's core—energy that can be tapped at steam vents and hot springs, as well as by other means. This heat can serve as the energy source in an electrical generating plant, just as fuel supplies such as oil and propane serve as the energy source in diesel engines and fuel cells, respectively. In addition to generating electricity, this energy source can be used for space heating and other uses.

Due to a number of geologic factors, the temperature of the ground increases with depth. The rate of increase, or geothermal gradient, varies by location but is believed to range between 0.01°C and 0.05°C. However, in areas of volcanic activity or hot springs, the gradient is much higher and very high temperatures exist near the surface. If water is trapped in these higher-heat areas and if the temperature is high enough, the resulting steam or fluid represents a potential medium for power production or domestic heating.

Several feasibility studies have been conducted to evaluate specific geothermal projects in Alaska, but there are no commercial installations at this time.

Analysis. Geothermal reservoirs have been used to produce electric power for decades, with the more prominent areas of application being California, Nevada, New Zealand, and Iceland. These resources are much like any other steam electric generating plants—steam is used to rotate a turbine-generator assembly. Geothermal resource characteristics can vary by temperature and phase (for example, steam, liquid, and so on). Therefore, steam for power production can simply be steam extracted from the reservoir or another fluid in a closed-loop system heated into steam by the geothermal hot water. Operating temperatures below 150°C are generally insufficient for power production, although such reservoirs might be used for domestic heating.

Geothermal reservoirs also have certain impurities that must be dealt with. If the source contains concentrations of corrosive materials, operating equipment must be designed appropriately and proper maintenance procedures must be implemented. Some of the impurities must be either re-injected into the reservoir through re-injection wells or hauled offsite.

A number of project components are an integral part of using geothermal resources. These include:

- A sufficient number of wells to extract the required amount of geothermal steam or fluid
- Re-injection wells to re-inject condensate into the reservoir
- Fluid/steam handling and conditioning equipment
- Boilers, if required
- Turbine-generator assemblies
- Control equipment
- Transmission lines from the project to the load center

Once operations begin, new wells (make-up wells) must be drilled from time to time to maintain resource pressure. Make-up wells may also be required if operating wells collapse or become plugged with rocks and debris. At times, the geothermal field is owned and operated by a third party, and payments are made in dollars per pound of steam or fluid taken.

This large infrastructure is very capital-intensive, and this high cost, when combined with inability to react quickly to large swings in load, results in most, if not all, geothermal facilities being operated as baseload resources. Once the large infrastructure is put into place, the capital investment is shielded from the effects of inflation. However, O&M costs of both the power plant and the wellfield are affected by inflation.

During the early 1980s, the Alaska Power Authority investigated the merits of a geothermal resource near Unalaska in the Aleutian Islands. A test well was drilled, and the results indicated that there was sufficient geothermal fluid for a power project. Both the state and private developers investigated a number of different development programs. The last was proposed in March 1996 by a joint venture that had recently acquired subsurface rights in the area to develop the project. Table 5-4 summarizes costs included in the proposal.

Table 5-4. Cost of Unalaska Geothermal Power Project

Item	Cost ($)
Capital Cost	
Project Construction	74,836,000
Well Field Development	15,270,000
Total	90,106,000
Annual Operating Costs	2,823,000
Cost Per Unit	
Installed Costs per kW	6,436
Annual Costs per kWh [b]	
Debt Service [c]	0.094
Other	0.033
Total	**0.127**

Source: Energy, Inc., 1996.
Notes:
1. Due to the proprietary nature of available data, it is not clear how the figures have been influenced by grants and subsidies
2. The installed capacity is 14,000 kW, net of station use and transmission losses.

[b] Based on an assumed 85,000 megawatt-hours (MWh) of usable energy per year.
[c] Assumes 30-year amortization period at 8 percent.

The resulting costs are slightly higher than the alternative cost of diesel generation. In this case, however, there were several important considerations when evaluating the merits of the project:

- Existing capacity in the area was more than sufficient to meet peak demands and reserve requirements. Therefore, the cost of geothermal energy had to be competitive with the variable cost of diesel generation.
- Most of the electric load in the area is associated with fish processing—an industry associated with risks in sustaining loads over the 30-year project life as well as shifting loads that result in lower amounts of usable power. Therefore, the potential power purchasers were not willing to enter into the long-term power sales agreements required for project financing.
- Risks associated with the large capital investment and underground resource extraction were not commensurate with risks associated with expected revenues.

Alaska has several large areas that have potential for geothermal reserves that could be used for power production. Besides the exploration at Unalaska, the state has also conducted drilling at Pilgrim Hot Springs on the Seward Peninsula. Six wells were drilled in the late 1970s and early 1980s, and a shallow reservoir of 90°C geothermal medium was found.

Based on the expected costs of the Unalaska Geothermal Project, a geothermal resource must be operated as a baseload resource in an area with relatively high loads for rural Alaska for it to be marginally economic. Lower capital costs or use of the geothermal medium for other purposes (for example, domestic heating) would enhance resource economics. Still, large loads will always be an important factor in determining whether a geothermal resource is economic.

Conclusions. It appears that geothermal power can be economic, but only on a relatively large scale and with a sufficiently long planning horizon. No sites have been found in rural Alaska where a geothermal resource is accessible, demand for electricity is sufficiently large, and conditions are stable enough for a long planning horizon. Therefore, this strategy is not recommended for further study.

5.3.5 Hydroelectric Power

Overview. Hydropower has the potential to reduce the cost of electricity in rural Alaska. Under the right circumstances, electricity generated by flowing or falling water can be less expensive than electricity generated by diesel systems. However, the right conditions include electric loads that match the availability of the resource and other factors. Given the limited number of sites where these conditions are met, hydropower does not have the potential to significantly reduce cost in a large number of villages. This strategy is not recommended for further review in the Rural Energy Plan.

Hydroelectric power is simply electric power generated from water in motion. It is renewable and nonpolluting (nonpolluting in the sense that no fuels are burned and no emissions are generated. There are impacts with stream flow modifications and other changes.) The following text provides an analysis of the potential for hydroelectric power to reduce the cost of electricity in rural Alaska.

There are several hydroelectric facilities operating in rural Alaska, including, but not limited to, installations at King Cove, Tazimina, Goat Lake, and Black Bear Lake (from Southwest Alaska to Southeast Alaska). In addition, there are several other installations that are being actively considered or planned for construction. Table 5-5 shows the size (in kW) and cost of several existing and planned hydroelectric facilities in rural Alaska.

Analysis. The potential of hydroelectric resources has been harnessed for centuries, and water has been used for electric generation since the 1800s. However, even with all this history and experience, hydroelectric power is probably the most difficult to define in terms of cost. Each potential site offers unique circumstances—geologic, environmental, water availability, or others—such that no two projects are alike.

Three general types of hydroelectric resources exist: storage, run-of-river, and pumped storage:

- **Storage** (sometimes referred to as impoundment type), makes use of a storage reservoir that is either naturally formed in a lake or impounded by a dam. Water is released through the generators when power is required, although environmental concerns typically require minimum releases at all times. Since the storage type can match power generation with power requirements, it has both capacity and energy benefits.
- A **run-of-river** system is composed of generators placed in structures in or alongside the river, and generation occurs with the natural flows. Since the timing of generation cannot be regulated, capacity benefits are based on the historical minimum flows during peak periods. Thus, capacity benefits for a run-of-river resource may be less than installed capacity or may not exist at all.
- **Pumped storage** consists of an impoundment area from which water is released during daily peak load periods. After passing through the generators, water is stored in another impoundment area until the off-peak period. At that time, the water is pumped back up into the upper impoundment area to be used the following day. Pumped storage is economic only if on-peak energy is expensive and off-peak energy (used for pumping) is inexpensive. Therefore, this type of resource is used for large, metropolitan areas, with nuclear or coal plants used as the pumping energy, and it has been implemented on a limited basis worldwide.

Integral components of a hydroelectric project include impoundment dams, diversion dams, powerhouses with turbine-generator assemblies, system controls, and transmission lines to load centers. Consequently, hydroelectric projects are highly capital-intensive and represent a considerable investment. However, O&M costs usually are fairly limited, and there is no cost for the fuel (water). As a result of this cost structure, costs typically are higher for hydroelectric projects than for other forms of generation in the early years but are not affected by inflation.

A number of hydroelectric facilities have been constructed in Alaska by the federal and state governments, electric utilities, and private developers, and watersheds exist in many parts of Alaska that can support additional systems. Costs of hydroelectric systems can vary considerably, given the conditions found with each project. Table 5-5 shows cost data for several hydroelectric projects in Alaska and demonstrates the range in costs that can be experienced.

Table 5-5. Cost Estimates for Hydroelectric Power, Based on Case Studies in Rural Alaska

Cost Item	Utility	Year of Construction	Installed Capacity (kW)	Potential Average Annual Energy [a] (MWh)	Capital Cost	
					Total ($Millions)[b]	Cost per kW ($)[c]
Black Bear Lake	AP&T	1995	4,500	24,000	10.3	2,289
Goat Lake	AP&T	1998	4,000	17,300	11.0	2,750
Tazimina	INN	1998	824	7,000	11.7	14,199
King Cove	King Cove	1999	800	-	5.9	7,375
Humpy Creek	Larsen Bay	[b]	520	600	2.1	4,448
Old Harbor	AVEC	[b]	500	3,300	2.5	5,000
Reynolds Creek	Haida Corp	[b]	1,500	11,500	7.5	5,000
Falls Creek	Gustavus	[b]	800	5,500	5.0	6,250
Pyramid Creek	Unalaska	-	100-260	-	-	-

Source: Data from Alaska Power and Telephone (AP&T), 2000; Petrie, 2000c; and Teitzel, 2000.
[a] Part may not be usable.
[b] Cost figures are estimates; others (where construction date is given) are actual figures.
[c] Assumes that all capital costs are debt financed at 8 percent over 30 years, with all energy usable
AP&T = Alaska Power and Telephone
- = Information not available

In most cases, energy sales from the hydroelectric resource are significantly less than the potential energy production and long-term economic benefits are based on future load growth. If such load growth does not occur, the utility can be placed into economic hardship. Clearly, however, some hydroelectric resources offer potential for savings in power generation, and those that are not cost-competitive in early years may become cost-competitive later since inflation has minimal effects on annual costs. In 1997, an assessment of hydroelectric sites for which published data could be found was conducted for the state. That study, the *Rural Hydroelectric Assessment and Development Study, Phase 1 Report*, prepared by Locher Interests, LTD, included the development of a database of existing and potential hydroelectric projects in rural Alaska. Published information was collected on 1,144 potential sites and 52 existing hydroelectric projects.

A two-step screening methodology was then applied to the database to develop a short list of promising sites. Projects with the following characteristics were eliminated:

- Projects larger than 5,000 kW or smaller than 25 kW
- Projects already under active development
- Projects for which:
  - ⇒ Construction costs had not been estimated previously
  - ⇒ Land status or environmental issues would create major obstacles to development
  - ⇒ Physical conditions at the site made project development impractical

The remaining 138 projects were analyzed with an economic screening model and subject to further review. These procedures resulted in the list being shortened to 11 projects, several of which are now in varying stages of development, including the following:

- Chuniisax Creek—Atka
- Falls Creek—Gustavus
- Unnamed Creek—Old Harbor
- Pyramid Creek—Unalaska

Some of the other projects among the 11 on the list have since been judged uneconomic or impractical. However, other projects in the specified size range that were not included might be viable projects that were eliminated for various reasons. For example, published information related to the project may have been inaccurate or outdated, or a project judged uneconomic could have been found to be economic if an alternative development plan had been available.

Conclusions. The present analysis, like the 1997 Locher report, concludes that hydroelectric power can compare favorably with diesel power, but only under the right circumstances. Both reports also show that no general analysis can be constructed to determine the overall potential of hydropower in rural Alaska. The Locher report demonstrated the need to look at detailed, site-specific data to evaluate each unique project.

Hydroelectric power has the potential to reduce the cost of electricity in rural Alaska, but most or all of the projects that the state has identified as having that potential appear to be under development already. Additional hydroelectric projects with favorable economics will likely be identified by local utilities or private developers rather than by a State of Alaska centralized survey and review effort. Therefore, development of small-scale hydroelectric projects is not recommended for aggressive implementation efforts by the state, or for further consideration in the Rural Energy Plan.

5.3.6 Interties

Overview. Interties offer numerous potential benefits including cost reduction from eliminating, or placing into reserve status, one or more diesel plants, better use of existing generating capacity in some areas, and improved reliability. However, the cost of constructing and maintaining interties in rural Alaska can be prohibitive. Even if a utility has a very low generating efficiency, interconnection with another utility would make sense only if the other utility had excess capacity, had significantly higher fuel efficiency, and was only a few miles away. Absent those conditions, the cost of building interties in rural Alaska typically exceeds the benefits.

The issues of whether SWGR lines are safe or existing codes (which do not permit such lines) are warranted have not been resolved. It is recommended that these issues be resolved in the remaining stages of the Energy Plan so that the economics of future intertie projects can be analyzed properly. It is not recommended that interties in general be studied in more detail.

Electric utilities in rural Alaska are, for the most part, electrically isolated from one another. Each utility has its own set of generating units to meet load, and these are operated and maintained by local personnel. Certain efficiencies may be gained, however, by electrically interconnecting one or more utilities. These efficiencies can include reduced fuel consumption, overhauls, operating personnel, and other benefits. In some cases, interties allow more usage from a high-capital/low-operating-cost project such as hydroelectric. The following text provides an overview of existing conditions and an analysis of the potential for interties to reduce the cost of electricity in rural Alaska.

Communities in many parts of Alaska have been connected to neighboring communities with electric transmission interties. Large interties connect major population centers (for example, there are lines that interconnect Anchorage, Fairbanks, and the Kenai Peninsula), and smaller lines connect various villages to each other or to a regional hub (for example, a line connects Bethel with Napakiak, and another line connects Craig, Klawock, and Thorne Bay). These interties provide valuable data for understanding the cost of constructing transmission lines in rural Alaska, the cost of maintaining the lines, and the benefits that can be expected.

Analysis. Capital and operating costs for interties vary by location and the type of terrain that the intertie spans. Table 5-6 summarizes capital costs of several small, rural interties in Alaska. Others have been built but cost data are not available. The data in Table 5-6 show that construction costs, in dollars per mile, can vary significantly depending on local terrain, voltage levels, and other factors.

Table 5-6. Capital Costs of Recent Rural Interties

Intertie Location	Length of Intertie (Miles)	Year Energized	Capital Cost ($Thousands)	Cost per Mile ($)
Skagway – Haines [a]				
	16		6,000	375,000
Craig – Klawock				
	6	1987	1,200	200,000
Black Bear – Thorne Bay				
	35	1998	2,450	70,000
Kasigluk – Nunapitchuk				
Original	3	NA	353	118,000
Upgrades/Rebuilds	3	Various	141	47,000
Proposed Upgrades	3	2001	1,068	356,000
St. Mary's – Andreafski/Pitkas Point				
Original	3	1985	182	61,000
Upgrades/Rebuilds	3	Various	193	64,000

Source: Figures on Black Bear-Thorne Bay from Crimp, 2000 (for 34.5-kilovolt [kV] Prince of Wales Intertie). Total cost estimates provided to DOE from AP&T.
[a] Submarine cable

If an intertie is constructed to connect two or more diesel systems, savings may accrue for the following reasons.

- **Increased Fuel Efficiency.** Generally, diesel generator efficiency (in kWh per gallon) increases with higher unit loading. This change in efficiency is more pronounced at the lower range of outputs than at the levels approaching a unit's maximum output. Interconnection of two load centers might allow a higher unit loading on one or more generators while others are shut off.

To gain a perspective on the amount of fuel that might be saved, the generating efficiency of a 350-kW, Caterpillar 3412 was reviewed. The summary in Table 5-7 provides the fuel efficiency at various output levels. As can be seen, significant increases in generating efficiency occur only if at least one of the primary units in the systems to be interconnected has an average output of approximately 30 percent of its rating. This output is quite low, and most utilities would run a smaller unit at these low loadings. Consequently, it appears that there would be significant fuel savings only under limited circumstances.

Table 5-7. Generating Efficiency of a 350-kW, Caterpillar 3412 Diesel Generator

Output (kW)	Efficiency (kWh per Gallon)
0	0.0
50	9.1
100	12.0
150	12.5
200	13.1
250	13.6
300	13.8
350	13.8

- **Reduced Maintenance Costs.** Diesel generators must undergo certain maintenance activities that are based on the number of operating hours. These activities include oil changes, top-end overhauls, and major overhauls. If one generating resource can supply the load instead of two, maintenance costs decrease. Costs of maintenance vary by resource, but the general rule of thumb is 1 to 2 cents per kWh for overhauls and miscellaneous variable maintenance.
- **Reduced Operator Costs.** If one generating location can be shut down due to interconnection, a utility may be able to reduce staff. However, power plant operators in rural utilities typically perform a variety of tasks unrelated to generation, and these activities will still be required. Furthermore, it may be necessary to maintain both power plants to ensure that they are available in the event of outages on the intertie or with the operating generators.

While there may be some benefits due to interconnection of two systems, the savings may not be enough to offset the installation costs. Additionally, intertie maintenance costs will be incurred. These, too, can vary considerably with local climatic and weather conditions. Routine maintenance includes annual inspections and right-of-way clearing, with the intervals between clearings as a function of the area where the intertie is located.

Another important consideration is the effect that weather can have. AVEC cited an example in which the 3-mile intertie between Kasigluk and Nunapitchuk was damaged by a winter storm. In February 2000, 11 poles were destroyed by wind and ice, and AVEC spent $750,000 to repair the line.

It appears that in many situations, interconnection of utilities will not provide significant benefits. However, there are instances in which interties can play a role—when additional capacity is required and another nearby utility has excess capacity. Communities with new (or planned) water and sewer systems are incurring significant increases in the demand for electricity, and it will be necessary for these communities to either add to their existing generating capacity or connect to other communities with excess capacity. However, based on $250,000 for a new generator and $100,000 per mile for construction of an intertie (hypothetical but plausible costs for illustrative purposes), the two load centers could not be more than 2.5 miles apart, absent other savings.

A benefit of interties that has not yet been discussed is that of increasing sales of a high-capital/low-operating-cost resource such as a hydroelectric project. As long as the resource has excess energy, interconnection of two or more systems can increase resource usage and decrease per-unit costs. AP&T was successful in doing this with its Black Bear Lake Project when the City of Thorne Bay was interconnected with its system.[36]

A report prepared in 1997 by Neubauer Engineering and Foster Wheeler Environmental Corporation for the DOE, *Rural Alaska Electric Utility Interties*, presents information on four existing interties (two in the Bethel area, one between Dot Lake and Tok, and one between Kobuk and Shungnak), 34 proposed interties, and 83 conceptual interties. Data on these interties was collected through a literature search as well as mail and telephone surveys. No minimum design criteria were used to define an intertie. Voltage, phasing, pole design, and other factors vary across the different interties in the data set. The key question was whether the transmission line would interconnect to a PCE utility. With regard to the economic potential of interties, the report concluded:

> "The feasibility of constructing any of (the) proposed interties in the near future…can only be determined by reviewing all historical studies, conducting more detailed engineering and environmental analyses, and systematically developing comprehensive cost estimates."

In a status report for the Rural Alaska Electric Utility Interties study, the contractor stated,

> "There may be some economy of scale by eliminating generation at one village in deference to generation at another, but probably not enough to warrant the debt service associated with a transmission line, additional generation at the supply source, and O&M cost to maintain standby reserves at the receiving village."

Calista Corporation continues to study the potential of connecting villages in the Bethel area and has experience with existing interties in that region. A consultant for Calista said the company is developing an energy plan that includes a 175-mile intertie between Bethel and the Donlan Creek Mine (with the intertie following the north shore of the Kuskokwim River). The long-range plan has not been developed, but could include distribution lines to as many as eight villages that are close to the proposed route. The consultant currently estimates that the 138-kV intertie could cost $400,000 per mile. Other components of the energy plan for the Bethel area and the proposal to supply power to the proposed Donlan Creek Mine by a transmission line include evaluation of alternative generation sources in Bethel (Bettine, 2000).

Single-Wire Ground Return

The Bethel-Napakiak Intertie, an 8-mile, 14-kV line, is an SWGR line that started to operate in 1981 (Neubauer Engineering and Foster Wheeler Environmental Corporation, 1997). An SWGR transmission line is less expensive to install than a conventional multi-wire transmission line and offers the potential to change the economics of several of the proposed interties (by lowering the capital cost). However, SWGR lines do not meet existing electrical codes. *Alaska Statute* 18.60.580, based on the National Electrical Safety Code, prevents the use of SWGR transmission lines in Alaska. According to the Alaska Division of Labor, Standards, and Safety, a separate ground return line is needed as part

[36] The point illustrated in this example is that the intertie was beneficial in increasing the usability of a hydroelectric facility—no attempt was made to analyze the net value of the intertie. In some cases, hydroelectric systems may have excess capacity and may be well suited to meet all or part of the baseload in a neighboring village if the villages were connected with an intertie.

of intertie installations (Dwyer, 2000). Exemptions are possible—as shown by the existence of the Bethel-Napakiak intertie—but the Division of Labor, Standards, and Safety does not think that these interties are safe or should be used.

Proponents of SWGR lines believe that they are safe, and the economics suggest that SWGR should receive more attention. The SWGR line between Bethel-Napakiak involved an inverted-V support with an insulator on the top, and the structure held in place by the conductor tension. The concept was simple enough that a large part of the installation could occur using only snow machines and hand tools. Large machinery was needed where deadends were installed, but the simple design and construction techniques significantly lowered the cost on a per-line-mile basis. The single-phase power was converted to polyphase at the terminus of the line, so the motors, pumps, and other 3-phase loads could operate.

Direct Current Transmission

Direct current (DC) transmission offers an alternative to the more traditional alternating current (AC) transmission. While DC transmission lines are typically more expensive to install than AC lines, line losses are lower on DC lines and other benefits are possible. For example, alternative technologies that produce DC power, including many fuel cells, could make DC lines more appropriate than AC lines in certain situations. In addition, there is a transmission distance at which DC lines are more economical than AC lines. For overhead transmission lines, the break-even distance (the point at which the cost of AC and DC lines are the same) is roughly 500 to 800 kilometers. However, for underground and submarine cables, the break-even distances are much shorter. For submarine transmission lines, transmission cost for cables of more than 20 kilometers can be lower if they are DC rather than AC.[37]

Conclusions. Interties may provide net benefits in certain rural locations. However, given the expected capital costs and limited savings in the average case in rural Alaska, it does not appear that interties should be aggressively promoted as a general strategy to reduce the cost of energy.

Individual cases may be identified in which interconnections make sense and are economically viable. Such cases might revolve around a hydroelectric or generating project with high capital costs, or other situations in which increased load would improve the resource economics. In addition, more cases might be economically viable if capital costs could be reduced with alternative approaches such as SWGR or DC lines.

The use of interties as a strategy in rural Alaska is not recommended for further evaluation in the next stage of the Rural Energy Plan. However, it is recommended that the questions of whether SWGR lines are safe or existing codes are warranted be resolved. At the same time, additional review should be conducted into the recent improvements in DC transmission line technology. For example, additional research could be conducted to determine whether DC lines are suitable or feasible in rural Alaska.

5.3.7 Microturbines

Overview. Microturbines are small combustion turbines (100-kW and smaller) that can be used in a variety of utility and commercial settings. Current designs include natural gas and liquid fuel (diesel) fired units. Models are currently being tested in Alaska, with no field data available at this point. High capital costs make electricity generated with microturbines more expensive than electricity generated

[37] For more information see http://www.greentie.org/class/ixd04.htm.

with diesel units. Production costs and technological advances related to microturbines can be monitored, but additional review of the technology is not needed at this time.

Large combustion turbines that use either natural gas or liquid fuels have been used for power production for a number of years. In recent years, technological advances have resulted in the development of smaller turbines that can be used in a variety of settings. These new, smaller combustion turbines are referred to as microturbines, and there has been a great deal of publicity about their prospects. One potential application is power production in remote areas. The following text analyzes the potential for microturbines to reduce the cost of electricity in rural Alaska.

Although combustion turbines have been used for power generation for decades, their use in rural Alaska has been limited. Generally, fuel use is slightly higher for combustion turbines than for internal combustion engines, but maintenance costs are significantly less. Consequently, combustion turbines are economic only when they are baseloaded. [38] Given that the smallest combustion turbine is in the 500-kW range, microturbines are found only where loads are significantly higher than this. Rural utilities that have installed combustion turbines include Barrow Utilities, Copper Valley, and Kodiak Electric Association. Smaller units are currently being tested by AVEC and others. These units include a 30 kW diesel-fired unit.

Analysis. In the past few years, significant progress has been made in the development of very small combustion turbines (100-kW or less). These units, commonly called microturbines, are relatively compact and are being developed for industrial users that would use both the electric and heat production. Furthermore, since microturbines have very low NO_x emissions, they can be used in large metropolitan areas once certain operating problems are resolved.

There has been a great deal of publicity regarding microturbines, and a number of companies are conducting research and development or are forming strategic alliances for implementing this technology. At this time, the three main developers are Elliott Energy Systems, Capstone Turbine Corporation, and Honeywell, which recently purchased Allied Signal. Of the three, Capstone is the only company with operating units in the field. Many of Capstone's operating units, estimated to be approximately 100 at this time, are in oil fields where noise is not a problem.

AVEC recently installed a natural-gas-fired, 30-kW Capstone unit at its headquarters in Anchorage. The unit operated for a period of time, but was shut down due to high noise problems. During the time that it operated, power quality was excellent. Two demonstration units, one in Barrow and one in Fairbanks, were field-tested for a short period, but both have been removed.

To date, all microturbines that have been installed have used natural gas or a derivative as its fuel. However, AVEC recently received a fuel-oil-fired (diesel) 30-kW Capstone unit that is being installed. Chugach Electric Association has a fuel-oil-fired unit on order, and Kotzebue Electric Association is waiting delivery of a 45-kW Elliott unit that will use fuel oil. (Showing that microturbines are still in infancy, the AVEC fuel oil microturbine was the fourth unit Capstone built to use that type of fuel.)

Given that this type of resource is still in its very early stages, cost and operating data are somewhat limited. However, the following information has been obtained in discussions with users and manufacturers' representatives.

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[38] Microturbines are suited for baseload use in rural Alaska because of the way they compare with diesel systems. In the Lower 48, combustion turbines are used primarily for meeting peak demand. Other alternatives such as combined cycle units, coal plants, and nuclear plants are typically used for baseloads. In rural Alaska, however, turbines are compared to diesel systems rather than these other alternatives. Compared with diesel units, turbines use more fuel per kWh, but have much lower maintenance costs. Consequently, turbines are most economic if they are used to generate baseload.

- **Fuel Efficiency (Gas-Fired)**—Fuel efficiency is claimed by Capstone to be approximately 27 percent, or 12,600 Btu per kWh. Experience of AVEC and others indicates that the actual efficiency is in the range of 20 to 21 percent. The reason for this discrepancy is that Capstone measures efficiency before inverter and transformation losses.
- **Fuel Efficiency (Fuel-Oil-Fired)—**AVEC has not completed installation of its new unit and has no fuel consumption data. Capstone indicates their tests show consumption to be 80 gallons per day at full output (30 kW). This equates to 9 kWh per gallon, or 15,500 Btu per kWh.
- **Capital Cost**—Expected long-term market prices of Capstone's units are expected to be approximately $46,000, or $1,533 per kW. On top of this, AVEC had to spend approximately $16,000 for site modifications and $10,000 for a 1,000-gallon fuel oil tank. The price of the fuel oil tank was high due to a 2-hour fire rating that was required at the site. The capital cost of the 75-kW Honeywell unit is expected to be approximately $650 per kW. However, voltage output is at 270 volts, and the required transformers and other equipment will increase this cost to approximately $850 to $1,000 per kW.
- **Heat Exchangers**—Heat exchangers for recovering heat are not included in the base capital costs. An air-to-water heat exchanger for the Capstone gas-fired unit costs approximately $7,000. Heat exchangers for the fuel oil units are not available at this time. Sulfur dioxide emissions from fuel oil form sulfuric acid, which corrodes the heat exchanger, and long-term solutions are still being researched.
- **Operating Costs**—At this time, there is insufficient operating data to provide clear estimates of long-term operating costs. However, certain observations can be made. The units do not have oil or water cooling systems, thus eliminating several regular maintenance items found with internal combustion engines. The units are being designed with the major components permanently connected to a single shaft with air bearings, and it is expected that at 40,000 operating hours these major components will require replacement. It is unknown what the cost of these replacements will be. The compressors for the gas-fired units may require maintenance at a shorter interval than 40,000 hours, but no clear data are available.

Table 5-8 summarizes these data on the cost of microturbines. The costs shown should be considered very preliminary. Annual maintenance costs were simply assumed to be $0.015 per kWh, approximately 50 percent greater than would be expected for a small (500-kW) combustion turbine.

Although the costs in Table 5-8 indicate a rather low-cost source of power for units using natural gas, natural gas is not available in most of rural Alaska. Furthermore, those areas that have natural gas have lower generation costs. All of the per-unit costs shown in Table 5-8 are based on a 95 percent plant factor, or baseload operations. Comparisons with internal combustion engines should therefore be made with similar plant factors. Table 5-9 compares the Capstone fuel-oil unit with an internal combustion engine at various load factors. The capital and operating costs of 13 microturbines are assumed to approximately equal the assumed capacity of the internal combustion resource.

Table 5-9 shows that the per-unit costs of the microturbine are affected significantly by its large capital costs and are always higher than costs for internal combustion generators. Since microturbines have a smaller capacity rating than typical internal combustion generator sets, they offer the benefit of better matching resource capacity with load. Consequently, the resource economics might be improved from that shown in Table 5-9 if one or more microturbines could be eliminated.

Table 5-8. Cost of Microturbines

Indicator	Indicator Data by Microturbine Manufacturer		
	Capstone	Capstone	Honeywell
Fuel	Natural Gas	Fuel Oil	Natural Gas
Capacity (kW)	30	30	75
Annual Energy (kWh) [a]	249,660	249,660	624,150
Installed Cost ($) [b]	$56,000	$56,000	$79,375
Installed Cost ($ per kW)	$1,867	$1,867	$1,058
Cost Summary—Full Output ($ per kWh)			
Debt Service [c]	0.023	0.023	0.013
Maintenance [d]	0.015	0.015	0.015
Fuel [e]	0.044	0.111	0.044
Total	**0.0744**	**0.1414**	**0.0646**

[a] Assumes 95 percent plant factor.
[b] Assumes $10,000 for site preparation costs.
[c] Amortized at 8 percent over 20 years.
[d] Assumed to be 50 percent greater than that expected for a small combustion turbine.
[e] Assumes efficiencies of 12,600 Btu per kWh and 15,500 Btu per kWh for gas-fired and fuel oil fired, respectively. Natural gas assumed to be $3.50 per MCF and fuel oil $1.00 per gallon.

Table 5-9. Comparison of Microturbine with Internal Combustion

Indicator	Microturbine	Internal Combustion
Unit Capacity (kW)	30	400
Number of Units	13	1
Total Capacity (kW)	390	400
Installed Cost	$728,000	$240,000
Amortization of Installed Cost [a]	$74,148	$24,445
Operating Costs ($ per kWh) [b]		
100 Percent Plant Factor	0.148	0.110
75 Percent Plant Factor	0.155	0.113
50 Percent Plant Factor	0.170	0.117
25 Percent Plant Factor	0.213	0.131

[a] Amortized at 8 percent for 20 years.
[b] Assumes 9 kWh per gallon for microturbine and 12 kWh per gallon for internal combustion; $1.00 per gallon fuel oil costs; maintenance costs of 1.5 cents for microturbine and 2 cents per gallon for internal combustion.

As with many fossil-fuel-fired resources used in rural Alaska, microturbines offer the opportunity to capture and use the heat. With centrally located generators, expensive heat distribution systems have to be built and maintained. Microturbines, however, can make use of the heat at less cost since the resource can be placed at or near the load.

Inclusion of a microturbine into a small load will affect the operations of the remaining resources, and fuel efficiency, maintenance requirements, and per-unit costs may change. Therefore, resource evaluations should be conducted by evaluating the entire system, not just a side-by-side comparison of per-unit costs.

Conclusions. Microturbines do not appear to be an attractive alternative to diesel generators at this time. Relatively few microturbines have been placed into operation, and those using fuel oil have no operating history. Consequently, there will probably be a number of design and operating problems to be resolved as further development occurs. Microturbines are not recommended for further review in the Rural Energy Plan. Technological advances and lower capital costs with increased production could change the economics appreciably. Such changes could be monitored without further study.

5.3.8 Small Coal Power Plants

Overview. The use of small coal power plants is not recommended for further study in the Rural Energy Plan. A thorough review of the literature and analysis of current economic conditions suggests that the potential of small coal power plants to reduce the cost of electricity in rural Alaska is very limited due to the small number of communities with economical access to the resource and sufficiently high demand for electricity.

Alaska has abundant coal resources in numerous areas throughout the state, and coal-fired electric generating plants are common in most parts of the world. As a result, a natural question is whether rural Alaska—or at least certain portions of rural Alaska—could benefit from the coal resources that exist in the state. The following text provides an analysis of the potential for coal power plants to reduce the cost of electricity in rural Alaska.

Several different mines have operated sporadically in the past in Alaska. At present, the Healy mine is Alaska's only operating coalmine of significance. Coal at Healy is used at a 25-MW, coal-fired resource owned and operated by GVEA, Aurora Energy's 22-MW cogeneration plant in Fairbanks, several small power generation facilities at the University of Alaska Fairbanks and U.S. Department of Defense installations in the Fairbanks area. In addition, coal from the Healy mine is exported to Korea. Another coal-fired resource in Healy, the Healy Clean Coal Project, was constructed by the state but is now being reevaluated for possible modifications.

Analysis. In 1998, the DOE commissioned a study that investigated the capital and operating costs of small generating resources using coal as the primary fuel. The result of the study was a computer model that estimated the costs for resource sizes ranging from 600 to 2,000 kW. Since construction and operating costs vary considerably throughout the state, the computer model developed these cost estimates using Anchorage as a base, and the user could apply adjustment factors to reflect local conditions.

Table 5-10 includes a summary of the costs expected for three coal plants of different size, as estimated using the DOE computer model without any cost adjustment factors. Capital costs of coal plants are relatively high due to the many and intricate components required for a coal-fired resource.

To estimate total annual costs, the cost of coal must also be estimated. In October 1997, Northern Economics completed a study that estimated the cost of coal at various destinations using coal from various mines in Alaska as well as from other areas. Based on the lowest source costs, the delivered cost (in 1997 dollars) of coal per million Btu ranged from $1.93 to $2.50 for selected coastal communities, $10.91 for McGrath, $7.06 for Galena, and $2.31 for Tok.

Table 5-10 includes a summary of total annual costs in dollars per kWh for three separate fuel prices. Due to the high capital costs, a coal-fired resource is most economic to run in a baseload manner. However, many of the rural utilities do not have loads that can support this type of operation for even a 600-kW resource. Accordingly, the costs in the table are also shown for two separate load factors, 85 percent and 50 percent.

Even using the assumptions that provide the lowest per-unit cost ($0.222 per kWh), electricity from coal is still significantly higher than from a diesel-fired internal combustion resource. The coal cost might be lowered by locating the resource closer to the mine and then transmitting the power to the load center, but given the cost of transmission lines, the cost of electricity for the consumer would still not be competitive with diesel sources.

In 1998, The Financial Engineering Company completed a power supply study for the City of Unalaska that investigated numerous resource options. Two different coal projects were investigated, 3,500-kW and 5,000-kW. The results of the analysis indicated that coal was one of the most expensive options investigated with present value costs higher than hydroelectric, combustion turbines, internal combustion, and wind used in conjunction with other resources.

Table 5-10. Cost of Electricity from Coal

Installed Net Capacity (kW)		600			1,000			2,000	
Net Efficiency (BTU/kWh)		26,183			22,720			20,130	
Installed Cost ($)		2,556,986			3,656,136			5,939,409	
Installed Cost ($ per kW)		4,262			3,656			2,970	
Amortized Capital Costs		227,130			324,765			527,582	
Annual Non-Fuel Operating		824,153			1,200,110			2,098,731	
Total Annual Costs (Non-fuel)		1,051,284			1,524,875			2,626,313	
Total Costs of Operations									
Cost of Fuel ($/million BTU)	2.25	7.50	12.00	2.25	7.50	12.00	2.25	7.50	12.00
85% Plant Factor									
Annual Energy (MWh)	4,468	4,468	4,468	7,446	7,446	7,446	14,892	14,892	14,892
Annual Costs ($/kWh)									
Debt Service	$ 0.051	$ 0.051	$ 0.051	$ 0.044	$ 0.044	$ 0.044	$ 0.035	$ 0.035	$ 0.035
Non-Fuel Operations	0.184	0.184	0.184	0.161	0.161	0.161	0.141	0.141	0.141
Fuel	0.059	0.196	0.314	0.051	0.170	0.273	0.045	0.151	0.242
Total	$ 0.294	$ 0.432	$ 0.550	$ 0.256	$ 0.375	$ 0.477	$ 0.222	$ 0.327	$ 0.418
50% Plant Factor									
Annual Energy (MWh)	2,628	2,628	2,628	4,380	4,380	4,380	8,760	8,760	8,760
Annual Costs ($/kWh)									
Debt Service	$ 0.086	$ 0.086	$ 0.086	$ 0.052	$ 0.052	$ 0.052	$ 0.060	$ 0.060	$ 0.060
Non-Fuel Operations	0.314	0.314	0.314	0.188	0.188	0.188	0.240	0.240	0.240
Fuel	0.059	0.196	0.314	0.051	0.170	0.273	0.045	0.151	0.242
Total	$ 0.459	$ 0.596	$ 0.714	$ 0.291	$ 0.410	$ 0.513	$ 0.345	$ 0.451	$ 0.541

Source: Calculated by The Financial Engineering Company.

Conclusions. This screening analysis reached the same conclusion as previous studies on the potential of coal to reduce the cost of electricity in rural Alaska: the potential is limited due to the small number of communities with both economical access to the resource and necessary load demands for sufficient economies of scale.

Dan Walsh at the University of Alaska Fairbanks, Minerals Industry Research Lab, believes that coal power could be economically viable only in the larger coastal communities of Alaska. He believes the villages would have to be on the coast to allow for marine transport of coal and be large enough to justify a relatively large-scale power plant, given the fact that economies of scale are needed to justify the high cost of a coal-fired power plant (Walsh, 2000). The only example discovered in this study where conditions might support a coal plant is in Bethel, where the demand for electricity from the Donlan Creek Mine might justify a coal facility and transmission line (Bettine, 2000).

This strategy is not recommended for further study in the Rural Energy Plan. Specific projects like the one that could be proposed in Bethel can be discussed on a case-by-case basis. It does not appear that coal has the potential to lower significantly the cost of electricity to a large number of residents in rural Alaska.

5.3.9 Biomass Plants

Overview. The potential of biomass plants, such as plants that burn wood, to reduce the cost of electricity in rural Alaska is limited by the heat content of the fuel supply, resource availability, and the relatively high capital and operating costs of generating facilities that use solid fuel. Biomass is not recommended for further study as a strategy to reduce the cost of electricity in rural Alaska. The use of biomass for space or district heating is discussed in Section 7.

Biomass plants are very similar to coal-fired resources in that a solid fuel is combusted to heat water into steam. The steam is then used to turn a turbine-generator assembly for power production. Biomass fuel includes peat, wood, municipal solid waste, or a variety of other products that can be burned. Fuels can be burned as is or can be enhanced with other fuels (such as fuel oil) to increase energy content and facilitate the delivery of fuel to the combustors. The following text provides an analysis of the potential for biomass plants to reduce the cost of electricity in rural Alaska.

Analysis. No data were found for any commercially operated facility that produces electricity from biomass (for example, wood or peat) in rural Alaska.

Energy content of biomass fuels varies by type and source. Table 5-11 provides a summary estimate of various biomass fuels available in Alaska as well as coal and fuel oil.

Table 5-11. Energy Content of Fuels

Fuel	Energy Content (Btu per Pound)
Coal	
Healy	7,800
Beluga	8,300
Omalik (Western Arctic)	13,000
Wood (Dry)	
	8,500
Peat	
Low	3,700
High	9,300
Municipal Solid Waste [a]	
	4,500
No. 2 Fuel Oil	
	19,660

[a] Can vary significantly

Because of the similarity in biomass and coal-fired power projects, capital costs of these two resources will also be similar. However, if the biomass facility uses a fuel with lower energy content, it may require a larger furnace, fuel storage area, and fuel handling equipment. For purposes of this analysis, adjustments for larger fuel system requirements are ignored.

Table 5-10 in Subsection 5.3.8, Small Coal Power Plants, showed that non-fuel costs ranged from $0.176 to $0.235 per kWh for baseload operations and $0.300 to $0.400 per kWh for a 50 percent plant factor. Based on these estimates, it appears that biomass facilities operated at a 50 percent plant factor would not be competitive with other sources of power no matter what the cost of fuel was. Baseload operations are closer to costs expected from a diesel resource but are still higher. Since the capital costs, which are shielded from inflation, do not represent a majority of the non-fuel costs, it is not expected that biomass facilities would be less expensive than diesel even in the long term.

Conclusions. Although biomass may not be economically viable for power production, domestic heating may be a candidate for its use. If the resource is used for both power production and heating purposes (cogeneration), the resource economics might improve. However, diesel facilities can also be operated in a cogeneration mode.

Biomass is not recommended for further study as a strategy to reduce the cost of electricity in rural Alaska. Biomass is discussed in more detail in Section 7, Space and Water Heating.

5.3.10 Solar Energy

Overview. Capital and installed costs of solar energy are expected to decline in the future, but not sufficiently in the near term to be considered as an alternative to diesel systems in rural Alaska. In addition, the lower summer electric loads in rural Alaska make it difficult to take full advantage of solar energy and to make photovoltaic (PV) cells economically viable. As a result, this strategy is not recommended for further study in the Rural Energy Plan.

Solar energy has been used for power production and domestic heating for decades, although until the 1980s power production has been limited to small, non-utility applications. The most common form of power production uses PV cells, but another method is to use the sun’s energy to heat a fluid into steam, which in turn drives a turbine-generator assembly.

The following text provides an analysis of the potential for solar energy to reduce the cost of electricity in rural Alaska. The following analysis deals solely with photovoltaics, primarily because cost data for other solar technologies are not available.

Lime Village has a 12-kW solar system. This system is currently in the rebuild phase, where PV panels are being added along with a 550-amp-hour battery bank and an electronic converter. The converter will be linked to the main diesel system dispatch controls.

Analysis. Photovoltaic cells are small, wafer-like cells that produce a small DC voltage when exposed to light. Thin semiconductor layers made from silica are placed between a front and back metallic grid, and a layer of glass or some other type of transparent encapsulant is placed on top to keep weather out. The process is both labor-intensive and expensive, and other components such as inverters and control equipment are required to connect the PV cells with the transmission and distribution system. A 1991 study by the National Association of Regulatory Commissioners (NARUC) estimated capital costs to be approximately $7,000 per kW and O&M expenses to be $0.005 per kWh.

Total per-unit costs depend on energy production, which is dependent on inverter losses (DC to AC), latitude of the facility, and amount of sunlight. Inverter losses vary by type, but a reasonable estimate to use is 10 percent.

There are more than 200 more hours of sunlight at the Arctic Circle than at the Equator. However, since the sun strikes the surface at a lower angle, the intensity of radiation is less at the Arctic Circle than at the Equator. Because of these two factors, the amount of radiation received is about the same at these two locations. However, in arctic regions, solar energy production is greatest in summer months when loads are low.

Energy production data from two PV installations at schools in Wisconsin have been collected since their installation in 1996. The data, summarized in Table 5-12, show that the average annual plant factor, excluding the first partial year of operations, was 17 percent. Table 5-13 provides an estimate of the cost of power from PV cells.

Table 5-12. Photovoltaic Cell Operating History—Two Examples

System Rating	System Size (kW) by Location			
	Antigo, Wisconsin		Brussels, Wisconsin	
AC	10.7		10.6	
DC	13.7		13.7	
	System Performance by Year			
Year	Energy (kWh)	Plant Factor (Percent)	Energy (kWh)	Plant Factor (Percent)
1996	4,883.4	10.4	5,056	13.0
1997	14,804.0	15.9	14,376	15.5
1998	15,359.3	16.5	16,482	17.8
1999	15,522.0	16.7	16,916	18.2
2000	12,785.0	18.4	11,828	17.0

Source: Utility PhotoVoltaic Group, 2000.

Table 5-13. Delivered Costs for Photovoltaic Cells

Item	Value
Installed Cost ($) [a]	7,000
Amortization of Installed Cost ($) [b]	713
Estimated Energy at 17 Percent Plant Factor per Installed kW	1,489 kWh
Cost Per Unit ($ per kWh)	
Debt Service	0.479
O&M [a]	0.005
Total	**0.484**

[a] Estimated in NARUC, 1991.
[b] Amortized at 8 percent for 20 years.

Although the costs estimated by NARUC probably have decreased since 1991, the costs in Table 5-13 show that capital costs must decrease dramatically before PV installations are cost-competitive. Furthermore, PV installations will not have capacity benefits since peak loads could easily occur at times when there is no sunlight at all. Consequently, the costs shown in the table may best be compared to a diesel's variable costs, which are on the order of $0.10 to 0.15 per kWh, depending on fuel efficiency, fuel cost, and selected operating costs.

Early PV cells were about 1 to 2 percent efficient in converting light energy into electric energy, whereas today's PV cells are about 7 to 17 percent. Consequently, the cost per installed kW has decreased significantly, and is expected to continue to decrease in the future.

Conclusions. It is conceivable that a solar power system could be economically viable in rural Alaska. For example, in a situation where daytime electric loads are high in summer months (when the resource is available) and diesel power is relatively expensive (due to high fuel costs), it is possible that solar power could be competitive with a diesel system. However, the number of places where these conditions might be met is quite small, and no evidence was found to suggest viability at present.

Due to the high capital cost of solar systems and limited number of suitable locations in rural Alaska where solar systems might be viable, this strategy is not recommended for further study in the Rural Energy Plan.

5.3.11 Tidal Energy

Overview. Tidal energy is a potential resource given the significant tidal ranges found in Alaska. However, the high cost and limited opportunity for application suggest that tidal energy is not appropriate for rural Alaska. This strategy is not recommended for further study in the Rural Energy Plan. There are no commercially operated utilities in rural Alaska that generate power using a tidal energy system.

Tidal resources use the energy in tides to produce power, with two primary types of systems available:

- **A generator submerged in an area with relatively strong tidal currents.** These currents vary throughout the day as the tide changes from flood to ebb tides, with the maximum velocity approximately halfway between flood and ebb. There are two flood tides and two ebb tides during a day (the actual cycle is slightly longer than a 24-hour period); therefore, tidal currents are at their strongest four times a day.
- **Impoundment**. This method stores water in an impoundment area during flood tide and releases the water through generators as it is required.

Because the timing of flood and ebb tides varies each day, generation may not be available when required. Therefore, tidal resources should be considered non-firm, and alternative sources of capacity must be held in reserve. Some tidal systems include storage components (for example, storing water at high tide in multiple impoundment areas for timed release throughout the day). However, these systems can be extremely large.

In addition, tidal power systems can be relatively expensive. Consequently, few tidal systems have been built worldwide and there is a very limited database of information. The following text provides an analysis of the potential for tidal energy to reduce the cost of electricity in rural Alaska.

Analysis. There are a limited number of tidal installations located throughout the world, and most are much larger than would be applicable to rural Alaska. However, Japan has had a 5-kW unit in operation since 1990, and the United Kingdom has had a 10-kW unit in operation since 1993. Operating data could not be obtained for these units.

Tidal Electric of Alaska, Inc., conducted a feasibility study of an impoundment-type tidal resource in Cordova. Initial cost estimates were $14 million (1998 price levels) for a 5,000-kW system, or $2,800 per kW. Cordova Electric later expanded its hydroelectric resource, and Tidal Energy of Alaska is looking at alternative sites.

A supplier of submersible units that could be used in tidal-flow applications was contacted for a price estimate. The estimate received from the supplier was for $720,000 for two 120-kW units. The price estimate included a tieline to shore, with the units assumed to be 0.5 mile from shore.

Tidal flow data were obtained for a site in Southeast Alaska so that energy production could be estimated. Based on the obtained flows, the annual energy production would be approximately 256,000 kWh per year for the 240-kW installation. The low load factor, 12.2 percent, is a result of production being a function of flow velocity to the third power. Consequently, as flows drop off from peak, production decreases at an even faster rate.

Table 5-14 provides the per-unit costs for the hypothetical 240-kW installation in Southeast Alaska. Installed costs include the tidal installation as well as an assumed 5-mile interconnection with the load center. Per-unit costs are quite high as compared to other alternatives, and this circumstance is a function of high capital costs as well as low energy production. If alternative sites with more sustained flows could be found, per unit costs might decrease. However, given the magnitude of the interconnection costs, it is expected that tidal installations will not be cost-competitive.

Table 5-14. Cost of Hypothetical 240-kW Tidal System in Southeast Alaska

Item	Value
Unit Size (kW)	240
Annual Energy (MWh) [a]	256
Capital Costs ($)	
Tidal Installation	720,000
Interconnection	500,000
Total	**1,220,000**
Cost per Installed Kilowatt ($ per kW)	5,083
Annual Maintenance Costs [b]	22,000
Cost Per Unit ($ per kWh)	
Debt Service [c]	0.485
Annual Maintenance	0.086
Total	**0.571**

Source: Calculated by the Financial Engineering Company, using data from Awerbuch, 2000, and National Oceanic and Atmospheric Administration, 2000.

[a] Based on a preliminary assessment of total energy production from a hypothetical site in Southeast Alaska with a 240-kW installation.

[b] Supplied by manufacturer.

[c] Based on amortization of total capital costs at 8 percent over 20 years.

Conclusions. The analysis of a hypothetical 240-W tidal power system in Southeast Alaska indicates that tidal power would not be competitive with diesel power. In addition, the number of villages that could implement this strategy is quite limited. As a result, this strategy is not recommended for further study in the Rural Energy Plan.

5.3.12 Wind Energy

Overview. The following text is a brief summary of an independent analysis of wind power systems in rural Alaska, prepared recently for AIDEA by ISER. The ISER analysis, in turn, draws upon work conducted by Global Energy Concepts (GEC) for Kotzebue Electric Association to evaluate the wind energy installation at Kotzebue. Based on ISER findings, wind energy is recommended for additional study in the next stage of the Rural Energy Plan.

In short, the economic benefits of wind power depend heavily on the wind resource. For example, the current wind power installation in Kotzebue, where average wind speed is 6.0 meters per second, is unlikely to deliver significant net benefits over diesel power. However, a similar installation in a place such as Nome, where the average estimated wind speed is 6.5 to 6.8 meters per second, could provide significant net benefits.

Analysis. In the early 1980s, a number of wind turbines were placed into operation in various parts of the country, including Alaska. At the time, oil prices were relatively high, and federal tax incentives had been enacted to encourage development of generating resources that did not use oil-based fuel. Unfortunately, many wind turbines failed after a relatively short period. This failure, combined with the collapse in oil prices, caused interest in wind generation technology to decline in the U.S.

Technological improvements have been made since that time, and there has been a resurgence in activity. In Alaska, Kotzebue Electric Association has obtained grant funds and installed several units. Three turbines were installed in 1997, and their initial operating success was instrumental in the association's decision to install seven additional units in 1999. Other utilities in the state that are investigating wind generation include AVEC and Chugach Electric Association. The community of St. Paul, through TDX Corporation, has installed a wind generation system and formed a company to market this concept in the global economy.

The Kotzebue experience provides the best set of actual data currently available. Table 5-15 summarizes the key assumptions and results for the 7-turbine installation that comprises phases 2 and 3 of the Kotzebue wind farm. Figures in Table 5-15 are from Phases 2 and 3 only because Phase 1 had significant costs associated with a technology learning curve that are probably not representative of actual costs. In Table 5-15, the column labeled "Kotz23gec" summarizes assumptions used by GEC in its most recent analysis (GEC, 2000). The column labeled "Kotz23coltc" reflects adjusted assumptions that ISER believes are more realistic (the acronym "coltc" is a reference to Steve Colt of ISER, the author of the study). The major adjustments that ISER made to the GEC assumptions are as follows:

- Decrease the avoided cost of diesel generation O&M to zero. Diesel variable O&M costs depend principally on the total number of hours of operation, not on kWh produced. There does not appear to be strong evidence that the Kotzebue installation has reduced the hours of operation for specific diesel units.
- Decrease the wind system annual O&M costs to account for the use of some in-house labor.
- Eliminate consideration of the federal Renewable Energy Production Incentive (REPI) payments.

With these adjustments, the Kotzebue Phase 2/3 wind farm has negative net benefits of approximately $211,000.

Nome is representative of a similar community but with higher average wind speed (slightly less than 7 meters per second, compared to Kotzebue's 6 meters per second). If a wind speed of 7 meters per second is substituted into the mix of assumptions for the Kotzebue example, the results improve significantly. This change is demonstrated in the column labeled "Kotz7ms" in Table 5-15.

Table 5-15. Net Benefit of Wind Energy Systems—Kotzebue Example

	Kotz23gec	Kotz23coltc	Kotz7ms
Assumption			
Average Wind Speed (Meters per Second)	6	6	7
Real Discount Rate (Percent)	2.0	3.0	3.0
Initial Fuel Price ($ per Gallon)	0.94	0.94	0.94
Real Fuel Escalation Rate (Percent per Year)	0	0	0
Initial Diesel Efficiency (kWh per Gallon)	14.9	14.9	14.9
Diesel Efficiency Increase Rate (Percent per Year)	0	0	0
Diesel Variable O&M Cost ($ per kWh)	0.0090	0	0
Wind Capital Construction ($)	1,020,000	1,020,000	1,020,000
Wind Energy Production (kWh per Year)	831,133	831,133	1,161,080
Wind O&M Cost ($ per Year)	14,600	10,000	10,000
Wind REPI Credit for 10 Years ($ per kWh)	0.017	-	-
Wind Overhaul, Year 15 ($)	35,000	35,000	35,000
Avoidable Cost of Fuel Storage ($ per Gallon of Capacity)	-	-	-
Result			
Present Value of Wind Cost ($)	1,372,994	1,238,470	1,238,470
Present Value of Benefits (Avoided Diesel Cost) ($)	1,468,781	1,027,728	1,435,719
Present Value of Net Benefits ($)	95,787	(210,742)	197,250
Present Value of Savings ($ per Annual Wind kWh)	0.12	(0.25)	0.17

Source: GEC, 2000, and ISER, 2000.
Note: A present value of savings of $0.20 equates to reducing the cost per kWh by $0.01 per kWh, one of the threshold criteria for advancing an examined strategy to the next stage of the Energy Plan.

The net benefits are close to the target of reducing the cost of energy by $0.01 per kWh. (Because ISER uses a strict present value analysis, it does not calculate a “levelized” cost of energy. However, the present value of a cost reduction of $0.01 per kWh, maintained for 30 years, is about $0.20. ISER used this figure as the target value for the present value of net benefits. In the column “Kotz7ms,” the present value of benefits is $0.17 per average annual kWh produced by wind turbines.)

Other communities that could use wind energy systems might be smaller and might have higher diesel prices, higher wind installation costs, and perhaps higher wind speeds. Some communities could have significant avoidable fuel storage costs, perhaps $8 per gallon of capacity. To explore such possibilities, ISER considered installation of one turbine identical to those installed in Kotzebue, with an average wind speed of 7 meters per second, in the model village introduced in Subsection 2.3. The model village uses 60,000 gallons of fuel per year at prices ranging from $1 to $1.50 per gallon.

Table 5-16 shows the results of ISER’s addition of a single wind turbine in the model village. In the column labeled “Model A,” the installation breaks even at a fuel price of $1 per gallon. With a fuel price of $1.50 per gallon, as shown in the column labeled “Model B,” the wind installation provides significant net benefits. These benefits far exceed the target of reducing the cost of provided energy by more than $0.01 per kWh.

Table 5-16. Hypothetical Small Village Wind Energy Analysis

	Model A	Model B
Assumption		
Average Wind Speed (Meters per Second)	7	7
Real Discount Rate (Percent)	3.0	3.0
Initial Fuel Price ($ per Gallon)	1.00	1.50
Real Fuel Escalation Rate (Percent per Year)	0	0
Initial Diesel Efficiency (kWh per Gallon)	14.	14
Diesel Efficiency Increase Rate (Percent per Year)	0	0
Diesel Variable O&M Cost ($ per kWh)	0	0
Wind Capital Construction ($)	150,000	150,000
Wind Energy Production (kWh per Year)	150,620	150,620
Wind O&M Cost ($ per Year)	3,000	3,000
Wind REPI Credit for 10 Years ($ per kWh)	-	-
Wind Overhaul, Year 15 ($)	5,000	5,000
Avoidable Cost of Fuel Storage ($ per Gallon of Capacity)	-	-
Result		
Present Value of Wind Cost ($)	212,011	212,011
Present Value of Benefits (Avoided Diesel Cost) ($)	210,873	316,309
Present Value of Net Benefits ($)	(1,138)	104,298
Present Value of Savings ($ per Annual Wind kWh)	(0.01)	0.69

Source: ISER, 2000.

Note: A present value of savings of $0.20 equates to reducing the cost per kWh by $0.01 per kWh, one of the threshold criteria for advancing an examined strategy to the next stage of the Energy Plan.

Conclusion. To achieve the target of reducing the cost of delivered energy by $0.01 per kWh, the present value of net benefits must equate to about $0.20 per kWh delivered annually. This target is met when average wind speeds approach 7 meters per second and the cost of diesel fuel is about $1.50 per gallon. There are several villages in coastal Alaska where these conditions appear to exist. Based on these findings, wind power generation is recommended for further analysis.

5.3.13 Other Strategies (Not Analyzed)

Two strategies reviewed but not included in the screening analysis were coal water fuel and ORMAT Energy Converters. The following subsections briefly address these strategies and the reasons why they were not analyzed in detail for this report.

5.3.13.1 Coal Water Fuel

Overview. Coal water fuel was not considered because of its relatively low energy density and lack of potential in the near term to reduce the cost of electricity in rural Alaska. Coal water fuel has roughly one-half to one-third the energy density that diesel fuel contains (Walsh, 2000). The volume of fuel that would need to be shipped by barge or air to rural Alaska would be significantly higher if coal water fuel were used as an alternative to diesel fuel.

Conclusions. Coal water fuel is not significantly cheaper than diesel fuel, and the transportation costs for coal water fuel would be greater than those incurred with diesel because of the larger volume that must be transported. Therefore, it was determined that coal water fuel does not have the potential to reduce the cost of electricity in rural Alaska at this time. (Significantly more coal water fuel than diesel fuel would be needed at a given location, and there are no cost savings for the fuel to offset the cost of shipping the additional fuel.)

5.3.13.2 ORMAT Energy Converters

Overview. ORMAT energy converters have found widespread use on the Trans Alaska Pipeline. These modular units convert heat energy (including diesel fuel) to electrical energy (with a significant heat energy byproduct). Although current technology is limited to modules of 3 kW, these units can be paralleled to provide higher outputs.

The initial capital cost of the units is high, but these units have effectively no maintenance. Reliability and low maintenance costs are the primary reasons that these units have widespread usage on the Trans Alaska Pipeline.

Conclusions. Current installed cost of the technology in Alaska is approximately $175,000 per kW, with estimated operating costs of $0.69 per kWh (estimate from EPS). These costs prevent ORMAT energy converters from having the potential to reduce the cost of electricity in rural Alaska.

5.3.13.3 Wave Power

Overview. Waves are a store of wind and solar energy that can be captured and converted into electricity. In the simplest form, wave energy involves modules or turbines that use wave energy to move air or water to produce electricity. Commercial generators are available from 0.5 to 3.5 MW.[39]

Analysis. The Wavegen Company advertises that its 0.5-MW generator can produce electricity for $0.05 to $0.09 per kWh, with sufficient wave energy (mean annual average incident wave energy from 15 to 30 kW/m). The company also claims the generators can easily accommodate add-on wind energy modules. These per unit costs compare favorably to the cost of diesel power in rural Alaska. However, these costs are based on a wave energy system that is significantly larger than the average demand in rural communities. (The average load in an AVEC village is approximately 100 kW. The smallest Wavegen system is 500 kW.) In addition, no mention is made in Wavegen's advertisements of transmission system costs (from the site of the wave energy system to a community), maintenance, or other items. Furthermore, the advertised capital costs for the smallest Wavegen system range from $1,800 to $2,400 per kW, roughly twice the current cost of diesel systems.

No data are available for the cost of wave power in Alaska. (Wavegen's advertised costs are based on research and pilot projects in the United Kingdom.) Moreover, no data are available on the number of coastal communities that have sufficient wave activity (as opposed to tidal fluctuations).

Conclusions. Additional research could be conducted based on data from companies such as Wavegen as more pilot wave energy systems are installed. When smaller systems become commercially available, a survey could be conducted to determine the number of potential wave energy sites in Alaska.

As smaller wave energy systems become available, individual communities or utilities may seek to explore the benefits of using the technology. However, data are not available at this time to justify a focused state effort to promote the use of wave energy.

[39] The Wavegen Company has several generators available and others under development.

5.4 Conclusions and Recommendations

Evidence reviewed to date suggests that wind energy is the only alternative energy technology analyzed that should be further evaluated in the next stage of the Rural Energy Plan.

In the absence of selective subsidies for other alternative energy technologies, implementing these other technologies in the near term in rural Alaska would be unlikely to produce positive net benefits on a significant scale. Individual projects that are cost-effective in the near term may yet be identified, depending on costs and characteristics of specific sites. Therefore, it is recommended that such proposals continue to be evaluated on a case-by-case basis. Continued research and development for alternative energy is also warranted over the long term.

Electricity: Strategies to Improve Reliability

6 Improving the Reliability of Electricity in Rural Alaska

Summary

This section focuses on strategies that could be implemented to improve the reliability of electricity in rural Alaska This preliminary analysis indicated that:

- Further study is warranted for microprocessor-based protective relaying systems.
- Net benefits are not sufficient to justify further study of reclosers with microprocessor-based controls.

6.1 Introduction

This section of the screening report describes existing conditions related to the reliability of electricity in rural Alaska. This section also describes the potential net benefits that could be realized with specific measures designed to improve the reliability of electricity in rural Alaska. Detailed analyses and value estimates are provided for the following measures:

- Installation of microprocessor-based protective relaying systems
- Installation of reclosers with microprocessor-based controls

This section ends with conclusions and recommendations for additional research.

Precision Power and EPS are not aware of a data set that shows the extent to which outages in rural Alaska are caused by inadequate reserves, or the amount or conditions of generating reserves to minimize potential outages. This issue of generating reserves can be addressed in the next phase of the Rural Energy Plan, when additional data from the Circuit Rider program are available.

6.2 Existing Conditions

For energy utilities, reliability is a measure of service interruption to a customer or group of customers. Table 6-1 summarizes rural Alaska interruption rates for 1995. (Detailed data on interruption rates in villages for the year ending 1995 are in Appendix A).[40] This table shows that in 1995 Alaska residents could expect 9.63 hours of interruption per person each year. For example, a community of 100 people could expect 963 hours of interrupted service in a year, or 9.63 hours per person.

Table 6-1. Service Outages in Rural Alaska, 1995

	Outage Duration (Hours per Year per Customer) by Cause				
	Power Supplier	Extreme Storm	Pre-Arranged Outage	Other	Total
Average for all Utilities	8.11	2.26	3.30	2.48	**9.63**
Maximum	95.83	30.00	18.75	13.50	**99.33**

Source: Alaska System Coordinating Council (ASCC) and State of Alaska, 1995.

[40] 1995 is the last year that the State of Alaska and ASCC compiled comprehensive statistics on electric utilities in rural Alaska, including interruption rates. While many larger utilities maintain their own records, compilation of statewide statistics is difficult without data from a single source. The cost quoted from Alaska Rural Electric Cooperative Association to revive this compilation is $35,000 annually.

In the absence of an interruptible tariff (agreement between electricity provider and consumer that power may be interrupted), consumers expect a high level of reliability from their power supplier. In addition, customers are demanding high-quality power. With sensitive electronics more prevalent today, including in rural Alaska, a power supply free of significant frequency deviations, voltage flicker, and sags and surges is required of the utility.

Anecdotal evidence from AEA staff and numerous managers at rural utilities suggests that outages often are caused by circumstances such as having to turn off generating equipment to check the oil level in engines (with no capability to switch to an alternative generator), running out of fuel, equipment failure, turning power off to service the system, and operator error. The extent to which outages are caused by particular factors is difficult to determine, given the lack of records on the cause or extent of outages in rural Alaska.

One exception to this lack of records is AVEC, which has data on outages by village for the past 5 years. In 1999 AVEC records, the average interruption time per customer was 13.62 hours. Mark Teitzel at AVEC explained that this figure includes scheduled and unscheduled outages, and is higher than similar figures for other providers such as Northwest Territories Power Company because AVEC turns power off for all service procedures (other providers allow more “hot service”). Data were not readily available to analyze the net benefits of capital projects undertaken by AVEC to reduce interruption time.

Microprocessor-Based Relays

An electromechanical relay is a device that uses electrical energy to move a disk, cup, or lever arm to actuate some type of control, usually to trip a breaker. Microprocessor-based relays—an alternative to electromechanical relays—can reduce the number or extent of outages in rural Alaska because the microprocessor-based relays are more reliable (fewer moving parts) and permit the system to perform self-diagnostics. For example, microprocessor-based relays have the ability to accurately discern and isolate system components before a total system blackout.

This ability of microprocessor-based relays has been demonstrated in many parts of rural Alaska. While this list is not exhaustive, the following PCE utilities have microprocessor-based relays in service in their systems:

- Cordova Electric Cooperative, Inc.
- Elfin Cove Electric Utility
- Nome Joint Utilities System
- Tlingit-Haida Regional Electric Authority

In addition to these PCE utilities, a number of non-PCE rural Alaska systems make extensive use of microprocessor-based relays for distribution, generation, and equipment protection. Cordova Electric Cooperative (CEC) is the only PCE utility of which EPS is aware that is using reclosers with microprocessor-based controls. The technology, however, requires less labor and expertise than older mechanical technology, and is infinitely more flexible in application. Cordova’s experience with reclosers has been positive. CEC is using the reclosers in a station configuration. According to the CEC manager of engineering and operations, outage durations have been reduced significantly, especially on CEC’s 13-mile feeder.

In addition to the PCE villages identified above, a number of non-PCE rural Alaska systems make extensive use of reclosers with microprocessor-based controls. Like relays, reclosers with microprocessor-based controls are ideal for utilities that may not have specific protection expertise, since the expertise and labor required for maintenance is less than for older mechanical designs.

6.3 Analysis of Strategies

The subsections that follow address issues related to reliability and provide strategies for improving the reliability and quality of electricity in rural Alaska. Net present value evaluations were conducted on all proposed strategies to economically evaluate their cost-effectiveness for a "model" village in rural Alaska. In this portion of the study, net present value is defined as the potential savings that may result from implementing the strategy minus the cost of implementing the strategy, adjusting for the effects of time over a specified planning period. Given this definition, a positive net present value is an indicator that the strategy should be considered an economically viable option.

To quantify the value of reliability, utilities use a measure called "the value of unserved energy" (VUE). VUE is differentiated among classes of consumers. Commercial customers generally have a higher VUE—if their power is interrupted, they are unable to produce income. Typical VUEs for urban Alaska utilities were used in these evaluations. These VUE values are listed in Table 6-2, which identifies the financial and engineering variables used to evaluate economic effects of outages. VUE estimates were derived from information provided by urban utilities in Alaska and are consistent with a feasibility study for transmission lines in the Railbelt area, prepared by Decision Focus in 1989 for Railbelt electric utilities. That report summarizes work by the Electric Power Research Institute on outage costs. The report shows that outage costs range from $0.21 per kWh to $10.17 per kWh. In conducting the feasibility study of transmission lines in the Railbelt area, Decision Focus used a cost of $5 per kWh for power outages in the residential sector, the value used in this analysis.

Fuel usage for the model village is shown in Table 6-3. This model represents a relatively small PCE village. Larger communities may experience larger benefits than suggested by this model community, in part, because larger communities can achieve economies of scale (costs per kWh of installed capacity decrease as the capacity of the generator set increases).

Table 6-2. Financial and Reliability Variables

Variable	Description	Value
Financial Variables		
WACC	Weighted average cost of capital	3 Percent
Useful Life	Useful equipment life	30 Years
Salvage Value	No salvage value is assumed at the end of the useful life.	$0
Reliability Variables		
VUE-R [a]	Value of unserved energy, residential	$5 per kWh
VUE-C [a]	Value of unserved energy, commercial	$21 per kWh
VUE [a]	Blended VUE, based on a load allocation of 50 percent commercial and 50 percent residential	$13 per kWh
SIR [b]	Service interruption rate, all types (hours per year per consumer)	10 Hours
DOP [c]	Percentage of outages that are distribution-caused	30 Percent
GOP [c]	Percentage of outages that are generation-caused	70 Percent

[a] Residential VUE based on values for typical urban utility in Alaska (see Decision Focus, 1989).
[b] The service interruption rate (SIR), all types (hours per year per consumer) is based on a typical rural utility value.
[c] The percentages of outages that are distribution caused (DOP) and percentages of outages that are generation caused (GOP) are based on typical values in the interruption data, and the consulting team's experience in utility operations.

Table 6-3. Model Village Annual Fuel Usage and Cost at Different Average Fuel Costs per Gallon

Average Fuel Cost per Gallon	**$1.00**	**$1.50**
Annual Fuel Usage (No. of Gallons)	60,000	60,000
Total Annual Fuel Budget	**$60,000**	**$90,000**

6.3.1 Installation of Microprocessor-Based Protective Relaying Systems

Overview. In addition to being viewed as a strategy to reduce the cost of electricity, the installation of microprocessor-based relays can be viewed as a strategy to improve the reliability of electricity in rural Alaska (this strategy was discussed as a way to reduce the cost of electricity in Subsection 2.3.2.5). Installation of microprocessor-based relays would improve the reliability of electricity because the new relays have been shown to have a much lower failure rate than older electromechanical relays and would reduce either the number or the extent of unplanned outages.

Analysis. No data are available on the extent to which outages have been caused by or made more extensive by problems with electromechanical relays. However, microprocessor-based relays have been shown (in rural Alaska and other areas) to have the ability to accurately discern and isolate system components before a total system blackout. This ability would allow outages to be limited to portions of a particular distribution system, rather than an entire system.

The value of reducing the number and/or duration of outages would depend on a number of factors, including the number of residents affected by an outage, the number of kWh used per hour by residents of rural Alaska, and the VUE. Table 6-2 shows the estimated value of reductions in outages, using service interruption data available for 1995 (summarized in Table 6-1) and average values from the 1999 PCE Annual Report.

Table 6-4. Potential Value of Reduction in Outages

Item	**Value**
Average kWh per Month per Person [a] (from 1999 PCE Report)	423
Hours per Month (24 Hours times 30 Days)	720
Average kWh per Hour per Person	0.6
Value per kWh Lost ($)	5
Value per Person of Reducing Outages by 1 Hour ($ per Year)	3
Value per Community of Reducing Outages by 1 Hour ($ per Year) [b]	1,227
Total Value of Reducing Outages by 1 Hour per Person in Rural Alaska ($ per Year) [c]	**238,131**

Sources:
[a] Calculated from average total kWh sales per month and population in PCE communities (from 1999 PCE Annual Report)
[b] Based on an average of 409 people per PCE community (from 1999 PCE Annual Report)
[c] Based on a total PCE population of 79,377 (from 1999 PCE Annual Report)

With average outages equal to approximately 10 hours per customer (meter) per year, a reduction of 1 hour per customer per year corresponds to a reduction of 10 percent. No data are available to determine whether microprocessor-based relay systems would provide a reduction of 10 percent. However, summarizing potential benefits can help frame future discussions. If these relays could reduce outages by 5 percent, then the benefits would be approximately $120,000 per year.

Conclusions. This strategy is recommended for further consideration to improve the reliability of electricity in rural Alaska. As shown in Subsection 2.3.2.5, the installation of microprocessor-based protective relays can be justified based solely on the cost savings from less maintenance and repair of relay systems (relative to the cost of maintaining and replacing electromechanical systems). In addition, microprocessor-based systems offer increased protection, or improved reliability. During the next stage of the Energy Plan, more work could be done to refine the estimate of the benefits associated with the strategy in terms of improved reliability.

6.3.2 Install Reclosers with Microprocessor-Based Controls

Overview. Reclosers, and their associated controls, perform the same function as a relay or a breaker. The primary difference between reclosers and relays or breakers is that reclosers are typically located on the distribution lines rather than in a substation or generator panel, where relays and breakers are typically found.

For larger villages, and those smaller villages that have an appropriate electrical system structure, the installation of line reclosers with microprocessor-based controls can limit an outage to a specific overhead feeder or feeder section. The use of these reclosers allows better sectionalizing and generally faster clearing times than with fusing, as well as the ability to automatically reenergize the line section for temporary faults. Relatively inexpensive ($20,000 installed cost) line reclosers are generally used by larger utilities to improve system reliability and to reduce prolonged outages.

The analysis for this strategy indicated that it should not be considered a generally viable option, but may be applicable for larger utilities,

Analysis. Reclosers are devices installed on the distribution line that detect a fault in the area protected by the recloser, and remove the source of power from that line section. By placing these devices out on the lines, rather than concentrated at the power plant or substation, smaller sections of the power system can be isolated for any given fault, thus reducing the number of consumers interrupted. For village systems, it also allows the power plant to remain online for a feeder fault, rather than tripping the plant when only a portion of the system may actually need to be de-energized.

The economic evaluation for the strategy of installing reclosers with microprocessor-based controls was conducted on a per-recloser basis. Table 6-5 identifies variables used in the analysis for this strategy. The data used for the cost of installation are based on numbers used by EPS working in actual installations in rural Alaska.

Table 6-5. Variables Used in Evaluation of Reclosers with Microprocessor-Based Controls Installation

Item	Cost ($)		Maintenance Interval (Years)	Average Monthly Usage per Customer [a] (kWh)	Percentage of Distribution Outage Minutes Reduced
	Installation	Maintenance			
Recloser	20,000 [a]	1,000	10	733	10

Source: Experience of EPS.
[a] Customers represent the number of meters in the model community.

It is assumed that 10 percent of fuse operations (or system faults resulting in a plant outage) could be avoided for each recloser installed on the system. Because most distribution line faults in overhead systems are temporary, the automatic clearing and re-energizing of the line by a recloser would avoid an outage that would otherwise require manual intervention.

For each blown fuse (or a plant outage caused by a fault that could have been avoided with the installation of a recloser), it is assumed to take 4 man-hours to locate the source of the problem, determine that the cause of the fault no longer exists, re-fuse the appropriate cutout, and verify that all consumers are again receiving power.

Given the SIR and DOP from Table 6-2, the consultants calculated the annual total number of hours of distribution related outages per community as follows:

SIR × number of consumers × DOP = 720 consumer-hours

Given the assumption that 10 percent (Table 6-5) of these outage minutes can be avoided by application of a recloser to automatically sectionalize the fault and restore power after the fault dissipates, a total of 72 consumer-hours per year are assumed to be avoided by the application of each system recloser. For each community of "model" size, it is unlikely that more than three or four reclosers could be used.

The unserved energy saved annually by the installation of each recloser is about 72 kWh per community. Using a blended VUE of $13 per kWh (Table 6-2) the annual savings for reduced outages is $936 per community.

The cost to restore these outages, while measurable (and significant) in urban systems, is assumed negligible in most PCE systems, because the plant operators, as a part of their normal duties, would be expected to restore the system. No cost has been attributed to the labor required for outage restoration.

Given the financial variables in Table 6-2 and the strategy variables in Table 6-5, the net present value of the installation is shown in Table 6-6.

Table 6-6. Net Present Value of Installing Reclosers with Microprocessor-Based Controls

Cost Variable	Net Present Value of Costs ($)	
	Status Quo	With Strategy Implemented
Recloser Installation	Not Applicable	20,000
Recloser Maintenance	Not Applicable	914
Cost of Unserved Energy	18,346	Not Applicable
Net Present Value of Costs	**18,346**	**20,914**
Net Present Value of Potential Savings [a]		**-2,568**

[a] Cost of implementation minus cost of unserved energy

Conclusion. The negative net present value indicates that the cost of installing reclosers with microprocessor-based controls exceeds the value of reduced outages. This strategy should not be considered a viable option. It may be applicable, however, for larger utilities, where there may be significant labor costs for outage restoration, and generally longer overhead lines, which may have a greater benefit in sectionalizing.

6.4 Conclusions and Recommendations

The installation of microprocessor-based protective relays would reduce the number and/or severity of power outages in rural Alaska. Moreover, the benefits of this strategy outweigh the costs, as measured by a net present value calculation. As a result, this strategy is recommended for further study in the Rural Energy Plan.

The installation of reclosers with microprocessor-based controls would also reduce the number and/or severity of outages in rural Alaska. This strategy, however, does not appear to offer benefits that would outweigh the costs in a typical setting. This strategy could be studied by utilities with specific needs, but is not recommended for further study as part of the Rural Energy Plan.

Precision Power and EPS are not aware of a data set that shows the extent to which outages in rural Alaska are caused by inadequate reserves, or the amount or conditions of generating reserves to minimize potential outages. This issue of generating reserves can be addressed in the next phase of the Rural Energy Plan, when additional data from the Circuit Rider program are available.

Space and Water Heating: Strategies to Reduce Cost

7 Space and Water Heating

7.1 Introduction

Summary

This section focuses on strategies that could be implemented to lower the cost of space and water heating in rural Alaska. This preliminary analysis indicated that:

- Improving the efficiency of heaters, improving insulation, and implementing other weatherization measures could generate savings with a total net present value of $32.8 million to $35.8 million.
- Strategies to reduce the cost of water heating could generate additional savings with a total net present value of $15 million or more, depending on the number of electric domestic hot water tank heaters in use in rural Alaska.

Further research in the area of improved efficiency for space and water heating is justified based on these potential savings. Further research is also recommended for waste heat recovery systems.

This section briefly describes existing conditions related to space and water heating in rural Alaska and presents an analysis of potential net benefits that could be realized with specific space and water heating strategies. The analysis is divided into subsections on space heating and water heating (7.3.1 and 7.3.4). Detailed analyses and value estimates are provided for the following measures:

- Increased insulation and other weatherization measures
- Heater retrofits
- Use of domestic hot water heaters as space-heating appliances[41]
- Converting electric water heaters to oil heaters
- Low-flow showerheads

This section also includes a discussion of the value of waste heat recovery systems, based on the theoretical potential to recover heat from a 140-kW generator and anecdotal information about existing applications. The section ends with conclusions and recommendations for additional research.

7.2 Existing Conditions

As noted in the section on end-use conservation (Section 4), the lack of data on the number or rural residences using different types of space heaters or water heaters makes it difficult to describe the existing conditions. Weatherization contractors and others familiar with the various heating appliances in use in rural Alaska say there is no pattern to the types of appliances used in different parts of the state and no way to know how many old, inefficient heaters are in use (Lee, RurAL CAP, and others, 2000).

[41] This strategy addresses both space and water heating, but is discussed in the subsection on water heating (7.3.4) since the technology is water heating. The overlap is in the application of the technology.

7.3 Analysis of Strategies

7.3.1 Space Heating

This section includes information on potential benefits of improving insulation levels, implementing weatherization measures, and improving heating systems (including replacing old heaters such as pot burners and cookstoves or making improvements to different boilers). This section also contains information on waste heat recovery systems and biomass heating systems. Where possible, this discussion begins with estimates of the value of implementing new strategies presented in other studies (previous studies for rural Alaska and recent studies for other regions), and concludes with estimates based on the most current information available for rural Alaska.

7.3.1.1 Insulation and Weatherization

Overview. The following text discusses the analysis of potential benefits associated with improved insulation and weatherization measures. The net present value of improved insulation is estimated to be $12 to 15 million, and the net present value of various weatherization measures (caulking and sealing and window and door retrofits) is estimated to be $8.5 million. Continued study of these measures in the next stage of the Rural Energy Plan is justified.

Analysis. RurAL CAP personnel believe that installing new heating equipment (primarily Toyostove brand heaters) and improving insulation in rural residences reduces fuel use for heating by 50 percent. They also believe that the savings could be attributed equally to the insulation and new heater (25 percent reduction in fuel use with installation of a new heater and 25 percent reduction in fuel use with addition of insulation). Whenever RurAL CAP finds a pot burner stove in a residence where it is conducting an energy retrofit, it replaces the heaters with Toyostoves. RurAL CAP typically does not replace Miller furnaces and other boilers. Personnel at RurAL CAP believe that pot burner heaters are only 50 to 70 percent efficient compared to the Toyostoves, which are 85 percent efficient. They also believe that Miller Furnaces and other boilers can be 75 to 80 percent efficient when properly tuned—making it difficult to justify replacing one of these heaters with a newer model (Lee, 2000).

The 1988 Analysis North report includes estimates of the value of adding insulation to existing homes, caulking and sealing, upgrading windows and doors, and retrofitting heaters. Superinsulating homes was found to be the measure with the greatest potential. The measure with the second greatest potential was upgrading the heaters used in rural residences. These two measures were found to have significantly greater potential than other measures related to space heating.

<u>Previous Estimates of the Value of Increased Insulation</u>

The value of superinsulating new homes was calculated based on a comparison of benefits and costs of building a home in rural Alaska to Alaska Craftsman standards instead of Alaska thermal standards. The incremental cost of additional measures, such as an airtight shell and the cost of a heat recovery ventilation system, was found to be $4,310 per home. The cost of additional insulation was based on shipment by barge. The cost of insulation would be lower for residents using bypass mail.[42] Benefits based on fuel savings were estimated to be $390 per year. Total benefits included fuel costs escalating

[42] Bypass mail is non-priority mail that is by designated air carriers in Alaska from the shipper's location or other origin point in the state to its ultimate destination without the U.S. Postal Service taking possession of the mail. The rates for bypass mail are based on non-priority ground service although such service is not available in rural Alaska.

at 1.5 percent per year for 40 years, for a total present value of benefits equal to $10,700 per house. The real discount rate used in the analysis was 3 percent (Analysis North, 1988).

Hindsight shows that fuel costs have not escalated at the rate assumed in the report, so the potential of superinsulating houses in Alaska may be overstated in the report. Still, the estimated benefits exceed costs by a wide enough margin that a reduction in the escalation factor does not affect the conclusion that significant savings are possible through energy efficiency measures. Even if fuel savings are not assumed to escalate (escalation rate of zero percent), the present value of benefits would exceed $8,200 and the net present value for the project would be more than $3,000 per house.

Data from Other Regions

Energy-efficient demonstration houses have been built in other areas, such as the Northwest Territories (NWT), where house performance was closely monitored. Case studies from Hay River, NWT, and the Keewatin District of the NWT show that superinsulation techniques and alternative heating systems can significantly lower heating costs and these lower operating costs do not necessarily require higher capital costs. For example, increased levels of insulation create situations where smaller heating systems are needed—lowering the cost of the heating system. However, most case studies show that actual savings are not as high as theoretical or projected performance. In the Hay River and Keewatin District demonstration homes, actual savings were lower than expected due to space heating systems not performing as well as advertised.

New Estimate of the Value of Increased Insulation and Other Weatherization Measures

Weatherization contractors confirmed that many existing homes in rural Alaska have been weatherized in recent years and new homes are being built with improved thermal characteristics. However, there are no data readily available that show the number of homes that have been weatherized or the value of different weatherization measures that have been implemented. The lack of data in this area stems in part from the fact that weatherization projects have so many components, including energy efficiency measures and other measures that focus on building durability, health and safety, and other factors. No two weatherization projects are the same, and there are no standards for allocating project benefits to different project components.

As mentioned in Section 7, the 1988 Analysis North report estimated that the net present value of building a home to Alaska Craftsman Home standards rather than Alaska Thermal Standard levels was $61 million. Making more conservative assumptions about fuel costs and other benefits might lower the net present value of this measure to $3,000 per house—approximately one-third of the value estimated in the report. In addition, the number of homes that could generate these savings is lower today than in 1988. These adjustments suggest that the current total net present value of savings from improved insulation levels might be 20 to 25 percent of the estimate in the 1988 Analysis North report, or $12 million to $15.25 million.

The 1988 Analysis Report also provided estimates of the value of caulking and sealing, door upgrades, and other components of weatherization projects. The report suggests that caulking and sealing could have a total net benefit of $23 million, window retrofits could have a total net benefit of $12 million, and door retrofits could have a total net benefit $2.6 million. If current benefits are 20 to 25 percent of the 1988 estimates due to the success of weatherization programs, improved construction techniques, and different assumptions about fuel costs and other figures, then the total net present value of caulking and sealing would be approximately $5 million, and the total net present value of window and door retrofits would be approximately $3.5 million.

Conclusion. The potential benefits associated with improved insulation and weatherization measures justify the continued study of these measures in the next stage of the Rural Energy Plan. The net present value of improved insulation is estimated to be $12 to15 million, and the net present value of various weatherization measures (caulking and sealing and window and door retrofits) is estimated to be $8.5 million.

7.3.1.2 Heaters

Overview. The following text discusses the analysis of potential benefits associated with heater retrofits. The net present value of heater retrofits is estimated to be $12.3 million. Continued study of these measures in the next stage of the Rural Energy Plan is justified.

Analysis. This analysis begins with a summary of previous estimates of the value of heater retrofits, and offers new estimates based on revised assumptions regarding the performance and cost of new heaters, as well as the level of use in rural Alaska of different types of heaters.

Previous Estimates of the Value of Heater Retrofits

The 1998 Analysis North report includes a description of space heater usage in rural Alaska, by heater type. The author explained that the figures are:

> "…the author's estimates, derived primarily from conversations with individuals who work extensively in rural Alaska and from Rural CAP survey data. It should be noted that there is significant uncertainty associated with this data. Data concerning the actual efficiencies of heating systems and the fuel splits (wood/oil/electric) is limited" (page 18).

Table 7-1 presents the Analysis North assumptions about the types of heaters used in rural Alaska, the efficiency of those heaters, and potential gains with relevant improvements. Table 7-2 shows the total savings possible with heater retrofits and replacements, based on a weighted average of savings and costs for different measures. Figures are given for a single residence (750 square feet, with expected annual fuel use for heating equal to 700 gallons) and all 20,000 PCE residences in 1988. Figures are taken from Analysis North, 1988.

The assumption in the Analysis North report that fuel savings will escalate at 1.5 percent per year was optimistic—actual fuel prices did not increase at 1.5 percent from 1988 to 2000. However, the potential savings are still such that the present value of benefits of heater improvements exceeds the present value of costs with much more conservative assumptions about benefits. In addition, the assumption that upgrades will need to be repeated after 12 years may overstate the cost of improvements.

Table 7-1. Level of Use of Different Heating Sources and Potential Fuel Savings with Upgrades

Existing Heating System	Saturation Level (Percent)	Efficiency Measure	Potential Fuel Savings (Percent)
All Oil	**40**		
Inefficient Furnace / Boiler	10	Replace Burner	22
Pot Burner / Cook Stove	24	Install New Heater	30
Efficient Heating System	6	Tune-up	5
Predominantly Oil	**30**		
Inefficient Furnace / Boiler	8	Replace Burner	18
Pot Burner / Cook Stove	18	Install New Heater	25
Efficient Heating System	4	Tune-up	4
Predominantly Wood	**15**		
Inefficient Wood Stove	13	New Stove	18
Efficient Wood Stove	2	None	0
All Wood	**15**		
Inefficient Wood Stove	13	None	0
Efficient Wood Stove	2	None	0
		Weighted Average	**18**

Source: Analysis North, 1988.

Table 7-2. Potential Savings with Heater Upgrades—1988 Analysis North Report

Entity	Current Fuel Use (No. of Gallons per Year)	Potential Savings (Percent)	Present Value of Costs to Achieve Savings ($)	Net Present Value of Savings ($) [a]
Single Home (750 square feet)	700	18	1,220 [b]	2,600
20,000 Homes [c]	14,000,000	18	24,000,000	52,000,000

Source: Analysis North, 1988.
[a] Based on 25-year planning horizon, fuel savings expected to escalate at 1.5 percent per year, and real discount rate of 3 percent per year
[b] Includes average initial cost of $713 and replacement measure after 12 years
[c] Approximate number of PCE customers in 1988

New Estimate of the Value of Heater Retrofits

Personnel at Rural Energy Enterprises in Anchorage believe that the heating sector in rural Alaska has been revolutionized over the last decade, with a high percentage of rural residents purchasing new energy efficient stoves (Zipperian, 2000). Significant changes in the level of use of different heaters and other factors require that the estimates of the value of heater retrofits from the 1988 Analysis North study be updated. This subsection provides that update.

The stove mentioned by most weatherization contractors as standard for rural Alaska is the Toyotomi, or “Toyostove,” Laser 30. This stove is capable of heating homes in the 700- to 750-square-foot range in Alaska and is available in rural Alaska at most AC stores, Rural Energy Enterprises, and other sources. It has a retail cost of $1,050 at the AC store in Nome (Dill, 2000). Cost in other locations will vary with shipping costs. While the aggregate figure of $12.3 million is much lower than the aggregate figure of $52 million shown in Analysis North, 1988, it represents a significant source of savings.

The primary obstacle preventing homeowners from improving the heating systems in their own homes despite the obvious benefits as shown in Table 7-2—beyond what they have already done in the unaided market—appears to be lack of capital. Weatherization contractors and others interviewed for this report explain that most residents of rural Alaska live month-to-month and seldom have the capital needed to purchase new appliances. The interviewees said that most residents would have to choose between buying a new heater and having money to pay for heating oil through the winter.

Table 7-3 through Table 7-7 show the performance of more efficient heaters (such as the Toyostove) and the cost and potential savings of installing more efficient heaters.

Table 7-3 shows manufacturer specifications for the Toyostove Laser 30 heater. The RurAL CAP web page says that the installation of a Toyostove like the Laser 30, "can save a rural resident $300 to $500 per year on fuel costs, depending on the condition of the house." Table 7-4 shows the net present value of the purchase of a Laser 30 under different scenarios.

If 5,000 new heaters were installed in rural Alaska, the total benefit would be in the range of $7.7 million to $24.5 million (based on the savings estimated by RurAL CAP and shown in Table 7-4). The relevant issues are the actual savings that are possible with upgrades and tune-ups, and the number of stoves that might need to be replaced in rural Alaska.

Table 7-5 shows the potential savings of replacing a pot burner stove with a new Toyostove, replacing the burner in an inefficient boiler, or performing a tune-up on a more efficient boiler. Fuel savings shown in the table are estimates from weatherization contractors and authors of the 1988 Analysis North report. Table 7-6 shows the current estimate of the level of use of different stove types. Figures are based on discussions with personnel at RurAL CAP, ACDC, and Rural Energy Enterprises.

If heating retrofits are performed on PCE homes (residences in rural Alaska) and it is assumed that there are 20,000 such homes, then total expected savings would be $12.3 million. Table 7-7 summarizes the potential savings.

While the aggregate figure of $12.3 million is much lower than the aggregate figure of $52 million shown in Analysis North, 1988, it still represents a significant source of savings.

The primary obstacle preventing homeowners from improving the heating systems in their own homes despite the obvious benefits as shown in Table 7-5—beyond what they have already done in the unaided market—appears to be lack of capital. Weatherization contractors and others interviewed for this report explain that most residents of rural Alaska live from month to month and seldom have the capital needed to purchase new appliances. Interviewees said that most residents would have to choose between buying a new heater and having money to pay for heating oil through the winter.

Table 7-3. Manufacturer Performance Statistics for Efficient Heater

Item	Performance at Various Settings		
	Low	Medium	High
Btu Rating	5,000	10,000	15,000
Efficiency (Percent)	87	87	87
Heating Area	20°F, 720 square feet 0°F, 600 square feet		

Source: Toyotomi, 2000.

Table 7-4. Potential Savings with New Heater—Four Planning Horizon Scenarios

Planning Horizon (No. of Years)	Amount ($)		
	Cost of Stove	Net Present Value of Stove [a]	Savings per Year
10	1,050	1,500	300
10	1,050	3,200	500
15	1,050	2,500	300
15	1,050	4,900	500

[a] Calculated with a discount rate of 3 percent

Table 7-5. Potential Per Home Benefit of Different Heating Retrofit Projects

Existing Heating Source	Retrofit	Potential Fuel Savings (Percent)	Potential Fuel Reduction (Gallons per Home per Year) [a]	Cost of New System ($)	Net Present Value of New System ($ per Home) [b]
Pot Burner	Install Toyostove Laser 30	25 - 30	188 - 225	1,050 [c]	1,750 – 2,300
Inefficient Boiler	Replace Burner	20	140	650 [d]	1,400
Efficient Boiler	Tune Up	5	30	175 [d]	270

[a] Assumes that homes heated with pot burners use 750 gallons per year, homes heated with inefficient boilers use 700 gallons per year, and homes heated with efficient boilers use 600 gallons per year. These figures give a weighted average of 700 gallons per home per year. Figures are consistent with numbers in the 1988 Analysis North report and findings from weatherization contractors.
[b] Assumes $1.00 per gallon and fuel savings are ongoing for 20 years, with a discount rate of 3.0 percent.
[c] Cost of Toyostove (Laser 30) at the AC store in Nome—prices will vary by location.
[d] Cost figures from Analysis North, 1998, and weatherization contractors—actual prices will vary.

Table 7-6. Potential Per-Home Benefit of Heating Retrofits

Existing Heating System	Saturation Level (Percent) [a]	Efficiency Measure	Net Present Value of New System ($) [b]
All Oil or Predominantly Oil	**85**		
Inefficient Furnace / Boiler	25	Replace Burner	1,400
Pot Burner / Cookstove	10	Install New Heater	2,000 [c]
Efficient Heating System	65	Tune-up	270
Other	**15**		
Inefficient Wood Stove	NA	None	0
Efficient Wood Stove	NA	None	0
		Weighted Average	**617**

[a] Figures are from conversations with weatherization contractors and weatherization program managers. The weighted average figure is a summary calculation based on other numbers in the table.
[b] Based on 20-year planning horizon and 3 percent discount rate.
[c] Average of $1,750 and $2,300 (from Table 7-5)

Table 7-7. Estimates of the Potential of Heater Retrofits

Action	Potential Savings (Net Present Value, $)	
	Weighted Average Per Home	Aggregate 20,000 Rural Residences
Heater Retrofits	617	12.3 Million

Conclusions. The potential benefits associated with heater retrofits justify the continued study of this measure in the next stage of the Rural Energy Plan. The net present value of heater retrofits is estimated to be $12.3 million.

7.3.2 Waste Heat Recovery Systems

Overview. Fuel savings are possible through waste heat recovery systems attached to or integrated with diesel-fired electric generating equipment. The benefits of the waste heat recovery system are equal to the value of the heating fuel displaced by the waste heat. For example, waste heat from a 140-kW generator could displace 3 gallons of heating fuel each hour if the heat from the generator is needed or used close to the generator.

Analysis. A 140-kW generator set running at 100 percent capacity has approximately 464,800 Btu per hour available from the coolant system for other usage. Assuming a 15 percent loss between the engine and the customer, an estimated 395,080 Btu per hour is available. This waste heat displaces approximately 3 gallons per hour in heating fuel. (In some cases, the heat loss between the waste heat collection system and end use could be less than 15 percent. Table 7-8 shows the value of waste heat collection systems with efficiency losses from 5 percent to 25 percent.)

Although waste heat recovery has attractive fuel savings potential, these benefits cannot be achieved unless a potential user is near the power plant. The economics depend on the amount of waste heat available, the demand for heat by potential users, the physical distance between the end user and the power plant, and the capital and operating costs of waste heat recovery and distribution equipment.

The ultimate value of a waste heat system depends on the value of the heat that is recovered. For example, if a washeteria or similar facility is close to a powerhouse that could supply a relatively high percentage of the facility's heat requirements, then a waste heat recovery system could be economically viable. Critical factors include the percentage of heat that is lost between the engine and the end user, the cost of constructing a waste heat distribution system, and the value of the displaced heating oil. Table 7-8 shows the amount of debt that could be financed with money saved from using less heating oil. Different levels of debt are shown for different loss factors between the engine and end-use customer, with an assumed cost of $1 per gallon for heating oil. (Engines of different sizes with different load factors would have different amounts of recoverable heat, with the actual amount depending on the type of engine and other factors.)

Table 7-8 shows that energy savings from a waste heat distribution system could support a total debt load of approximately $125,000 to $145,000 (assuming that the debt was to be repaid over 10 years at 8 percent interest). A waste heat recovery system that cost more than $145,000 would be difficult to justify for a 140-kW generator set—the fuel savings would not justify the project expense. Some allowance would also need to be made for maintenance and repairs on the recoverable heat distribution system.

Table 7-8. Evaluation of Savings with Waste Heat Distribution System

Btu per Hour from Coolant System (140-kW Engine)	Heat Loss Between Engine and Customer (Percent)	Fuel Oil Displaced (Gallons per Hour) [a]	Annual Fuel Savings at $1 per Gallon ($) [b]	Allowed Debt (10-Year Loan at 8 Percent) [c]
464,800	5	3.3	25,000	168,000
464,800	10	3.1	23,000	154,000
464,800	15	2.9	21,600	145,000
464,800	20	2.7	20,000	135,000
464,800	25	2.5	18,600	125,000

Source: Calculated by Northern Economics.
[a] Amount of fuel oil displaced, based on 137,500 Btu per gallon (the average of 135,500 Btu per gallon for No. 1 fuel oil and 142,800 Btu per gallon for diesel (figures from www.gasplants.com)
[b] Based on 7,446 hours per year of operation (85 percent of 365 days times 24 hours per day) to allow for maintenance and other downtime.
[c] Dollar amount that can be repaid over 10 years at 8 percent annual interest rate, using annual fuel savings as the annual debt payment.

Circuit Rider Program data include information on whether a utility has a waste heat system installed and whether that system is in operation. Anecdotal evidence suggests that most of the waste heat recovery systems provide heat to schools, city offices, and other facilities. Kris Noonan at AEA said that of all waste heat facilities installed in the last 5 years (new facilities installed by AEA are required to have a waste heat system), only one did not have another facility close by that could use the heat. Mr. Noonan also believes that less than 25 percent of rural utilities have functioning waste heat systems. This assessment suggests that many villages could benefit from the addition of a waste heat recovery system.

In cases in which another facility is not located near the powerhouse to take advantage of recoverable heat, another option that could be considered is using the heat from generators to heat fuel tanks and/or distribution lines. Keeping fuel storage tanks and distribution lines warm enough could permit the use of less expensive, higher-Btu No. 2 diesel fuel (compared to No. 1 diesel fuel, which is sometimes required in colder months).

Conclusions. The potential of waste heat recovery systems to be economically viable depends critically on the end use of the heat. If the heat is needed close to the powerhouse, then the benefits of the waste heat collection and distribution system are more likely to justify the costs. Anecdotal evidence suggests that there usually is an end user or customer that can use the heat located close to the powerhouse.

The potential savings in avoided fuel costs appear to be significant, and the number of villages that could benefit from the installation of a heat recovery system appears to be large. More work is needed to substantiate these preliminary findings and analyze more formally the net benefits of waste heat systems. In addition, more work is needed to determine the true potential value of using recoverable heat to keep fuel storage tanks and distribution lines warm enough to permit the use of No. 2 diesel. Setting aside concerns about the lack of available data, this strategy is recommended for further study.

7.3.3 Biomass

Overview. Under the right circumstances, biomass heating systems can be economically viable. However, biomass systems appear to be economically competitive with oil systems only with long planning horizons and usually with optimistic assumptions about the price of biomass fuels. The potential of biomass systems is limited and this strategy is not recommended for further study.

Biomass heating systems include wood stoves for domestic use to large-scale boiler systems for district heating or for heating larger institutional facilities. The focus of this study is on larger scale systems that could reduce the cost of heating for a large number of residents in rural Alaska. Small-scale systems for single-family dwellings are not considered in this analysis.

A variety of biomass heating systems have been constructed in rural Alaska and more are planned or being considered. Facilities have been operated in communities such as Chicken and are under consideration for cities such as McGrath. The only existing or planned systems found in the literature are wood-fired. Municipal solid waste could be used as biomass and solid waste incinerators have been used in Alaska. A large-scale solid waste incinerator has been operated in Juneau and another was operated in the past at the Naval station in Barrow (the latter facility has been dismantled). Heat has not been captured from these incinerators.

Analysis. In 1996, USKH, Inc., prepared the *Rural Alaska Heat Conservation and Fuel Substitution Assessment* for the Division of Energy. One section in the report focused on wood fuel substitution and included a summary of existing and planned projects to replace or to augment fuel oil heat with wood-fired heating systems. That report offers several case studies, including Dot Lake, Elim, Grayling, McGrath, and Tanana. In all cases, the net present value of a wood fired heating system is higher than the net present value of a conventional oil system using a planning horizon of less than 20 years. The analysis of biomass heating projects in Dot Lake, McGrath, and Tanana suggest that a sufficiently low price for delivered wood can make the present value of costs for a wood system less than the present value of costs for an oil system. However, this finding is only true with a planning horizon of 20-years or longer. USKH concludes that, "In all cases the cost of wood and the manual labor to fire the wood boilers is less than the cost of oil on an annual basis. However, when the capital cost of the installed wood equipment is included, the present value of costs for Oil is less than Wood for 5, 10, and 20 year periods" (page 18).

A critical factor in these cases where wood appears to be competitive is a long enough horizon—20 years or longer—to allow for the capital cost of the wood equipment to be fully amortized and the lower fuel costs to generate sufficient benefits. For example, in the Elim case study, USKH found that wood had a delivered cost that was 60 percent that of oil. However, the cost of extra boiler equipment and cost of manually stoking the boilers 1,300 times per year offset the savings from lower fuel costs. Under all scenarios considered by USKH, including 5-year, 10-year, and 20-year planning horizons, the present value of costs for the biomass system in Elim exceed the present value of costs for the oil-fired system. The analysis for the system in McGrath resulted in almost the same findings.

No additional data were found in the current study to counter the findings of the 1996 USKH study. Economic calculations in the McGrath Biomass Heating Demonstration Project (Strandberg, 1999) suggest that significant grants are necessary to make the project viable. For example, $1.6 million of the total cost of $1.8 million must be secured in grant funds to meet project goals, even with a 20-year planning horizon.

A supplement to the 35 percent design phase report for the McGrath Biomass Heating Project (MBA Consulting Engineers, 2000) shows that the proposed wood-fired system compares favorably to an oil-fired system only with a 30-year planning horizon and favorable assumptions for the cost of wood. For example, the present value of costs is lower for the wood-fired system than the oil-fired system with a 30-year planning horizon and if wood is available at $100 per cord or less. The 1996 USKH study used $125 per cord for the delivered cost of wood. If the price of wood is more than $100 per cord or the planning horizon is reduced to 20 years, the figures in the MBA report suggest that the oil system would be less expensive than the biomass system.

Table 7-9 shows the heat content of biomass fuels common in Alaska and fuel oil (Diesel No. 2). The table shows that dry wood has less than half the heat content per pound than found in fuel oil. This difference suggests that a wood-fired biomass facility would require a larger furnace, fuel storage area, and fuel handling equipment to provide the same amount of heat as a oil-fired system. The cost of the extra infrastructure is the reason that the facilities studied in Alaska require a longer planning horizon (20 years or longer) for benefits to compare favorably to costs.

Table 7-9. Energy Content of Fuels

Fuel	Energy Content (Btu per Pound)
Wood (Dry)	
	8,500
Peat	
Low	3,700
High	9,300
No. 2 Fuel Oil	
	19,660

In general, the economic viability of biomass systems depends on the availability and cost of biomass, cost of additional equipment, and the cost of other fuel stocks, especially fuel oil. Villages that have or are close to a sawmill and have access to mill byproducts, and that pay relatively high prices for diesel fuel, may find that a biomass heating system is economically viable. Villages that would have to harvest cordwood for the biomass system and that pay lower prices for diesel are likely to find that a biomass system is not competitive.

Looking beyond the heating sector, it is possible to consider other benefits when estimating the net value of a biomass system. Important linkages could exist between economic development and biomass heating. For example, a community that installs a biomass system may be able to help support a local sawmill that provides jobs in the community. Such linkages, however, are beyond the scope of this screening analysis.

Conclusions. Biomass systems can be economically viable in the right situation. However, the number of locations is likely to be quite small in rural Alaska where biomass fuels are available at a low enough cost to offset the high capital cost of the biomass system. In comparison to other strategies that can reduce the cost of heating (such as heater improvements), this strategy does not have the potential to significantly reduce the cost of heating in the short term in rural Alaska. As a result, this strategy is not recommended for further study as part of the Rural Energy Plan.

7.3.4 Water Heating

This subsection includes an analysis or review of several strategies related to reducing the cost of heating water.

7.3.4.1 Domestic Hot Water Tanks as Space Heating Appliances

Overview. With more energy efficient homes, one possible way to reduce space heating costs is to use domestic hot water tanks (DHW) as space heating appliances. The potential benefits of this strategy are based on the following facts:

- DHW tanks are less expensive to buy, to install, and to maintain than most boilers.
- DHW tanks use less space than boilers
- DHW tanks can be used with both hydronic and forced air heating (distribution) systems.

However, energy costs are typically higher with DHW tanks than most boilers because DWH heaters tend to be less efficient. This strategy is not recommended for additional study at this time—the analysis indicated that the strategy will become viable only when tank heater efficiencies and durability improve substantially.

Analysis. A recent study by the Northwest Territories Housing Corporation (NTHC) to test the potential of space heating with DWH tanks resulted in the recommendations that such that standards be changed so that DWH could be approved as combined space and water heaters, and that manufacturers improve the efficiency and lifespan of the equipment. In short, the test showed that using DHW tanks as space heating appliances would be economically viable if tanks were more efficient and durable (NTHC, 2000).

DHW tanks can be used as space heating appliances because space heating loads have declined with more energy efficient housing. For example, NTHC found that when it upgraded insulation levels in its residential units, DHW load was beginning to exceed the space heating load.

When NTHC tested DHW tanks as space heaters, it considered the cost to purchase, ship, and install the initial system, equipment efficiency and operating costs, maintenance costs (including the availability of parts and qualified repair personnel in rural Canada, and replacement costs. The heaters tested in the study were oil-fired heaters. Table 7-10 summarizes the initial costs.

Table 7-10. Comparison of Costs—Domestic Hot Water Tanks and Boilers

Item	Cost ($)	
	Boiler	DHW Tank (Oil-Fired)
Initial Costs		
Capital	4,334	2,324
Installation	300	160
Shipping	120	45
Total Initial Cost	**4,754**	**2,529**
Annual Maintenance Cost [a]	**242**	**90**

Source: NTHC, 2000.
[a] Maintenance costs were calculated for a 10-month period.

In the NTHC study, the DHW heaters were less expensive to install and maintain, but typically cost $360 per year more in energy costs than boilers. This difference suggests that the higher cost of the boiler can be recovered in approximately 6 years.

The NTHC study concludes that the potential of DHW tanks as space heaters is sufficient to warrant changes in standards in regulations and to hope for improvements in DHW system efficiencies. The conclusion is somewhat different in the context of the Rural Energy Plan. DHW tank heaters do not appear to be economically justified as space heaters if the planning period is longer than 6 years. As a result, this strategy is not recommended for additional study.

Conclusions. The uncertainties surrounding use of domestic hot water tanks as space heating appliances are such that this strategy is not recommended for additional study. This strategy will become viable only when tank heater efficiencies and durability improve substantially.

7.3.4.2 Conversion of Electric Hot Water Heaters to Oil-Fired Hot Water Heaters

Overview. This subsection compares the efficiency of electric hot water heaters and oil-fired hot water heaters when used for domestic hot water. Savings with conversions are estimated to be $9,400 per unit, based on the following analysis. The potential benefits associated with conversion of electric heaters to oil heaters justify the continued study of this measure in the Rural Energy Plan.

Analysis. As noted in Subsection 3.4, End-Use Conservation, AVEC provides the following tariff advice to its customers:

> "The Utility does not recommend electric water heaters, electric space heating appliances, electric dryers (especially commercial), electric saunas, or other similar devices whose main purpose is to produce heat electrically in the Utility service areas, since cost comparisons with alternate methods are generally unfavorable and, in some cases, cause detrimental effects to the Utility system."

This advice became effective in November 1977. AVEC wrote a letter in March 2000 to VSW about alternatives to electric hot water heaters. In the letter, Brent Petrie from AVEC requested that VSW consider and recommend oil-fired rather than electric hot water heaters. The letter also highlights the Toyotomi and Monitor brand high-efficiency, direct-vent, oil-fired units (Petrie, 2000). AVEC also noted that the addition of a 6-kW electric water heater can more than double the number of kWh used by rural residents in a month. The letter states:

> "An AVEC residential customer without water and sewer may use 150-250 kWh per month. Adding a 6 kW electric 40-gallon hot water heater may use another 250-600 kWh per month. It is not unusual for an electric hot water heater to use more electricity than all of the other uses such as lights, TV, freezers and appliances combined."

An electric hot water heater that uses 250 to 600 kWh per month would cost a rural household $80 to $192 per month (at $0.32 per kWh). In addition, the electric utility with many new electric hot water heaters might face capacity constraints. However, the relevant issue in this instance is not just how much it costs to heat water with an electric heater, but how much savings is possible with alternatives to electric hot water heaters.

The 1988 Analysis North report includes an estimate of the potential of converting electric water heaters to oil. That report assumes that electric water heaters use 4,800 kWh per year and states that this kWh usage is slightly less than the national average. In comparison, an oil-fired water heater with 63 percent efficiency consumes 200 gallons of fuel per year. Assuming that a diesel generator unit produces 12 kWh per gallon, it would require 400 gallons of fuel to generate the 4,800 kWh needed for the electric heater. In addition, a resident of rural Alaska might pay $0.32 per kWh, or $1,536 per year to operate the electric hot water heater ($0.32 × 4,800). This amount is roughly $1,300 more than the cost of 200 gallons of fuel per year.

The Toyotomi instantaneous, oil-fired water heater referenced in the AVEC letter to VSW has a manufacturer's suggested retail price of $1,550 and is available in Anchorage at locations such as Rural Energy Enterprises and North Heat. Manufacturer specifications show that the heater is 92 percent efficient and uses 1.046 gallons of fuel per hour of operation to produce 130,000 Btu.

Assuming that 64 gallons of water are heated per day and fuel cost is $1.00 per gallon, annual operating costs for this heater would be $137 (increasing to $151 at $1.10 per gallon). In comparison, annual operating costs for an electric heater sized to produce a similar amount of hot water each day would be $1,706 at $0.30 per kWh.

Table 7-11 summarizes the energy usage and costs of different water heaters.

Table 7-11. Cost of Water Heaters

Item	Annual Energy Requirements [a]	Cost ($) Capital Cost	Annual Energy Costs [b]	Present Value of Costs Over 20 Years [c]
Electric Tank Heater (50-Gallon)	5,690 kWh	340	854	13,000
Oil Tank Heater	180 gallons	-	180	-
Toyotomi On-Demand Heater	137 gallons	1,550	137	3,600

[a] From table in AVEC, 2000.
[b] Based on $0.15 per kWh (avoided cost) and $1 per gallon
[c] Uses real discount rate of 3.0 percent

The potential savings with oil-fired heaters (all models, but especially on demand heaters) compared to electric heaters appears to be significant. Calculations based on energy usage figures from manufacturers (in AVEC letter to VSW) show that energy-efficient, on-demand heaters would be far less expensive to own and to operate than an electric tank heater. Estimates from other studies, such as Analysis North, 1988 also show suggest that significant savings are possible with the installation of new heaters and/or modification of old heaters.

Table 7-12 shows the potential total net present value of switching from electric tank heaters to on-demand oil heaters, not including consideration of bulk storage demands. Savings per unit are based on the difference between the cost of owning and operating an electric tank heater ($13,000 over 20 years) versus an oil-fired on-demand unit ($3,600 over 20 years).

Table 7-12. Potential Aggregate Benefits from Replacing Electric Tank Heaters with Oil-Fired On-Demand Units

No. of Units Replaced	Net Present Value of Potential Savings ($) Per Unit [a]	Aggregate per 1,000 Units
1,000	9,400	9.4 Million

[a] $13,000 minus $3,600 (see Table 7-11)

In addition to this theoretical information on the value of converting electric hot water heaters to oil-fired heaters, experience and opinions of staff at ACDC and AVEC suggest that the potential for this strategy may be significant. Dan Berube at ACDC and Brent Petrie at AVEC both identified this strategy as important. ACDC converted electric water heaters to oil-fired units in Egegik and believe that similar projects could be conducted in other communities. AVEC has had to request that building contractors working in several rural communities not install electric water heaters as planned, and that they consider the use of oil fired heaters instead.

Conclusions. The potential benefits associated with conversion of electric heaters to oil heaters justify the continued study of this measure in the next stage of the Rural Energy Plan. Savings with conversions are estimated to be $9,400 per unit. Additional research should address questions related to bulk fuel storage and fuel costs.

7.3.4.3 Low-Flow Showerheads

Overview. This subsection presents the analysis of potential benefits associated with low-flow showerheads. The analysis indicated that the net present value of use of low-flow showerheads is about $5.8 million, and continued study of this measure in the next stage of the Rural Energy Plan is justified.

Analysis. Devices that reduce the overall demand for hot water, such as low-flow showerheads, also serve to reduce overall expenditures on hot water. Water use with a traditional showerhead is 3.5 gallons per minute and water use with a low flow showerhead is 2.5 gallons per minute. The 1998 Analysis North report uses this figure, along with following assumptions:

Analysis North Assumptions

- Low-flow showerheads would save 39 gallons of oil annually per residence (residences with showerheads and oil-fired water heaters).
- Fuel costs are $1.55 per gallon and are expected to increase at 1.5 percent per year.
- 10,000 PCE homes have showerheads.
- New showerheads cost $25 and will last 25 years.

These assumptions suggest total net present value of savings equal to $1,150 per residence and aggregate net benefits of approximately $12 million. The potential value is less with the following more conservative assumptions:

Updated Assumptions

- Fuel costs are $1 per gallon.
- No escalation is expected in the real price of fuel.

With these changes, the net present value of savings for each residence is $550 and aggregate net benefits of approximately $5.8 million.

New low-flow showerheads perform much better than earlier models, but still have a poor reputation.

Conclusions. The potential benefits associated with low-flow showerheads justify continued study of this measure in the next stage of the Rural Energy Plan. The net present value of use of low-flow showerheads is estimated to be $5.8 million. Additional research should address uncertainties surrounding the number of showerheads in rural Alaska, as well as questions related to consumer perspectives and willingness to use low-flow showerheads.

7.3.4.4 Planning

Overview. This strategy may relate more to implementation than any given technology. Still, contractors and developers working in rural Alaska need to be educated on the effects of the use of heat tape, electric domestic hot water tank heaters, and other devices that may be relatively inexpensive to install but have a relatively high total (life-cycle) cost—especially in rural Alaska.

Conclusion. No data are available to support evaluation of the extent to which contractors install appliances and heat tape that require greater-than-necessary amounts of electricity for a given result. Only anecdotal evidence from personnel at AVEC and comments from various weatherization contractors suggest that this is an important issue.

7.4 Conclusions and Recommendations

Significant gains are possible with strategies to reduce the cost of water and space heating in rural Alaska. Improving the efficiency of heaters, improving insulation, and implementing other weatherization measures could generate savings with a total net present value of $32.8 million to $35.8 million. Strategies to reduce the cost of water heating could generate additional savings with a total net present value of $15 million or more, depending on the number of electric domestic hot water tank heaters in use in rural Alaska. These potential savings suggest that these strategies should be considered for further research.

Table 7-13 summarizes the total net present value of different measures as demonstrated in this section.

Table 7-13. Summary of Potential Savings with Strategies to Reduce the Cost of Space and Water Heating

Item	Total Net Present Value ($Millions)	Location of Additional Information
Improved Insulation	12 – 15	Subsection 7.3.1.1
Caulking and Sealing	5	Subsection 7.3.1.1
Window and Door Retrofits	3.5	Subsection 7.3.1.1
Heater Retrofits	12.3	Table 7-7
Waste Heat Recovery Systems	NA	Subsection 7.3.2
Biomass	NA	Subsection 7.3.3
Electric Water Heater Conversions	9.4 per 1,000 units	Table 7-12
Low-Flow Showerheads	5.8	Subsection 7.3.4.3

NA = Firm estimates not available at this time

Future research could include consideration of the impact of implementing these strategies on the cost of fuel storage and other items.

Bulk Fuel Storage: Strategies to Reduce Cost

8 Bulk Fuel Storage: Construction

8.1 Introduction

Summary

This preliminary analysis of methods for managing construction of state-funded upgrades to bulk fuel tank farms indicated that:

- Savings are possible with alternative practices for constructing bulk fuel storage facilities. Specifically, competitively bid and design-build construction could result in costs that are comparable to or below current force account construction costs.
- These contracting methods should be tested and evaluated in individual communities before they are implemented on a large-scale multi-community project.

None of the alternatives examined suggest that more study of construction practices is needed in the second stage of the Rural Energy Plan Phase 2B.

The purpose of the work summarized in this section is to identify and evaluate different methods of managing and executing the construction of state-funded bulk fuel tank farm upgrades, primarily in small rural Alaska communities. The primary objective of the analysis is to compare existing practices with alternative scenarios to identify potential construction management methods that may be more cost-effective.

Subsection 8.3 includes an analysis of the following approaches to tank farm construction:

- The state manages construction and the owner constructs with force account labor (current model) (Option 1).
- The state manages design and the contractor constructs; the contractor is selected through a conventional competitive bid process (Option 2).
- Request design-build proposals from private contractors for tank farm upgrades for individual communities (Option 3).
- Request proposals from private contractors to design and construct upgrades for selected groups of villages (Option 4).
- Request proposals from qualified private entities to design, build, own, and manage new consolidated tank farm(s) (Option 5).
- Existing tank farm owners manage, design, and construct their own upgrades or replacement projects (Option 6).

The section concludes with recommendations for alternatives to current practices. Section 9 includes five case studies to set the stage for a review of financing issues related to bulk fuel storage facilities.

8.2 Existing Conditions

The Rural Energy Plan Phase 1 report documents the current condition and existing practices for bulk fuel storage in rural Alaska. To summarize, the State of Alaska maintains a database that tracks the number and condition of bulk fuel storage tanks in 161 of Alaska's 195 rural communities. There are approximately 1,020 tank farms in small rural communities, with a total estimated storage volume of 51 million gallons. The Phase 1 report also indicates that more than 98 percent of these existing tank farms had significant deficiencies at the time the database was completed. Common deficiencies included no secondary containment, leaks, poor piping systems, no fencing, and other problems.

Since the database was initiated in 1992, AEA has undertaken a program to improve bulk fuel storage conditions and practices in many rural communities. In recent years, the emphasis has been on consolidating tank farms, so that each community only has one tank farm to operate and maintain. AEA uses in-house staff and engineering contractors to complete the planning and design phases of tank farm upgrade, and uses force account construction using primarily local labor forces to complete construction.

This subsection provides some of the background information used to develop and evaluate the alternatives considered in Subsection 8.3.

8.2.1 Project Selection Process

A planning document prepared in February 1999 by AEA (formerly Division of Energy) outlines the basic process that AEA uses to select projects for funding. The goal of the process is to give highest priority to communities with the most serious tank farm deficiencies. This priority listing (Appendix B) is used as a first screening level for identifying communities with the most need. A summary of additional criteria that are used to refine the selection is provided below.

- Citations or warning letters from the U.S. Environmental Protection Agency (EPA), the U.S. Coast Guard (USCG), or other regulatory agencies
- Imminent threat to health and safety
- Alternative or supplemental funding opportunities that are community- or region-specific: examples include federal funding through the U.S. Department of Housing and Urban Development (HUD) or state funding through the U.S. Department of Education
- Financial need based on existing costs and income levels within each community

8.2.2 Grant and Construction Administration Process

A description of the current process used to administer grants and manage design and construction projects was provided by AEA and is included below.

8.2.2.1 Grant Agreement

AEA grants project funding to the ultimate project owner who, in turn, designates AEA as the project manager in charge of all aspects of project development. Table 8-1 provides a general summary of the responsibilities of each project participant.

Table 8-1. Tasks and Areas of Responsibility in Tank Farm Construction (Status Quo)

Function	Responsible Party
Administration of Funding	AEA staff Trustee Accounting Firm
Development of Project Ownership and Management Agreements	AEA Staff
Preparation of Project Design, in Consultation with Local Participants	AEA Staff Engineering Design Contractors
Acquisition of Permits and Site Control	AEA Staff Engineering Design Contractors ROW Contractor
Oversight of Materials Procurement	AEA Staff and Engineering Design Contractors
Project Construction	AEA Staff Force Account Foreman and Labor Construction Management Contractors Specialty Contractors
Preparation of Regulatory Plans	Contractors

8.2.2.2 Administration of Project Funding

Project funding is not released to the grantee, but instead is placed with a trustee accounting firm. The trustee firm issues checks for project expenses only on specific direction of AEA for approved payroll and invoices.

8.2.2.3 Project Construction Labor

For the typical project, AEA selects a foreman who is experienced in rural tank farm construction and in most or all of the requisite skills, including sandblasting and painting for tank refurbishment, equipment operation, and often welding.

Village residents provide all project labor unless a particular skill is not available among the local labor force. Typically, unavailable specialists include electricians and pipe welders. Sandblasting and painting to refurbish existing tanks is usually accomplished by local labor with the foreman's participation and supervision. Site preparation and other heavy tasks are accomplished with local equipment run by local operators.

Typically, the local government prepares a list of village residents who are available to work on the project, along with a statement of their skills and experience. When the foreman asks for workers of a given skill level, the local government selects individuals from the list. The foreman retains the option, however, to go back to the local government for a replacement if someone does not perform adequately.

Unless a certified welder is available in the village, welding is performed either by the foreman or by a welder brought in from outside the village—sometimes from elsewhere in rural Alaska, sometimes from Anchorage or Fairbanks. Electrical work typically is performed by AEA staff or by a contractor.

Except for an occasional contractor (for example, the electrician), all project labor, including the foreman, the village workforce, and any outside hires such as welders, are placed on the payroll of the local government as force account employees. Neither Davis-Bacon nor Little Davis-Bacon wage requirements apply. AEA establishes the pay scale—local labor typically is paid between $12 and $18 per hour, depending on skill level. The wage rate is set to reflect the prevailing wage within the community for comparable skills. Skilled workers from outside the community are provided with a place to stay in the community and with per diem to cover meals and other incidental expenses.

The supervisor submits timesheets to AEA for project payroll. On approval, AEA directs the trustee accounting firm to issue payroll checks, ensuring that all required payroll taxes and deductions are properly paid or withheld.

Some supervisors rely more on outside hires for skilled labor, particularly in areas such as sandblasting and painting, where the work might be done by local labor under adequate supervision but might be done faster or more reliably by outside hires with more experience. The description above, however, is accurate for the typical case.

8.2.2.4 Procurement/Fabrication of New Tanks

Because the project funds are formally granted to the future tank farm owner, the state procurement code does not apply to the acquisition of materials, supplies, and services required for project development. AEA, acting as the grantee's agent, could legally procure whatever is needed without going through a competitive bid process. As a matter of policy and cost containment, however, AEA puts procurement related to tank farm development out to bid.

With regard to bulk fuel storage tanks, AEA determines how many new tanks of what size and configuration will be needed for a given project as the project design nears completion. Depending on the condition of existing tanks and the costs of refurbishment, anywhere from all to none of the tanks to be placed in the new facility may be purchased new. Once the requirement for new tanks is known, AEA puts them out to bid. The winning bidders have often, but not always, manufactured the new tanks in Alaska.

8.2.2.5 Preparation of Regulatory Plans

Typically, the AEA design contractor prepares all of the regulatory plans that may be required by agencies such as the USCG and the EPA, including the Spill Prevention, Control, and Countermeasures Plan, the Facility Response Plan, and the Operations Manual.

8.2.2.6 Pertinent Regulations

Title 36 of the *Alaska Statutes* outlines the current regulations for public contracting in Alaska. Several requirements are pertinent to a comparison of force account to conventionally bid projects. A summary of some of these requirements is as follows.

- Contractors that perform work on public projects of value greater than $2,000 in Alaska are required to pay employees the prevailing wage rate for work of a similar nature in the region (Little Davis-Bacon rates) (AS 36.05.010).
- Workers employed by a municipal entity are not subject to the requirements of the prevailing wage rate as described in the item above.
- As a matter of policy, the state will grant an employment preference to residents of Alaska (AS 6.10.005).
- Municipal entities may require a preference for or minimum percentage of local hire when soliciting bids from contractors. For example, the contract can be written such that a contractor

that proposes to use local hire will be given a preference (higher score) than contractors that propose to import all workers. Alternatively, the community can require, by contract, that a certain percentage of the workers on the project be hired locally. Although this practice is not specifically allowed by statute, neither is it prohibited. There is currently no set statutory minimum or maximum percentage of local hire that may be required by contract.

8.2.3 Current Tank Farm Construction Costs

Recently, the Denali Commission retained Integrated Concepts and Research Corporation (ICRC) to complete a study to evaluate management and costs of the bulk fuel storage tank farm program currently under the direction of AEA. The results of the study are summarized in a report dated August 24, 2000, and titled *"Final AEA Bulk Fuels Program Management Audit -- 1999 Commission Funded Bulk Fuel Projects -- Various Alaska Villages."*

In summary, the results of the study indicated that the cost of projects constructed by AEA to date averaged $7.42 per gallon, which was within 3 percent of AEA's projected cost of $6 plus a 20 percent contingency ($7.20). Although final design estimates exceeded the budgetary cost of several projects, it was determined that these overruns were primarily due to the inclusion of additional storage volume during final design rather than problems encountered during construction or underestimation of unit construction costs. The AEA costs were also found to be comparable to construction costs of other tank farms constructed by utilities or government agencies in rural Alaska.

The study recommended that preliminary design (35 percent) be completed before funding for final design and construction of the tank farms in individual communities was provided, so that more accurate estimates of construction costs could be obtained.

Although several planned projects had estimated construction costs that significantly exceeded the budgetary number of $7.20 per gallon, the study did not include research as to the possible reason for these higher costs. For example, difficult construction conditions such as over-excavation, frozen soils, or slope stability problems that increase the cost of construction were not considered.

8.2.4 Current AEA Practice

The focus of AEA when addressing bulk fuel tank farm issues in rural Alaska is to provide a consolidated facility for the entire community, with the goal of having one entity primarily responsible for maintenance. This practice has often required including private entities in these public tank farm projects. Although participation is voluntary, tank farm participants often include the city, the local Native corporation, the tribal council, the school, and the power plant. Private parties can be included if they historically have sold fuel in the community.

Although private entities are not required to contribute, many, such as privately owned stores, often contribute a portion of the project expenses. Although these entities do not usually contribute the total cost of their portion of the tank farm, their contribution is often significant.

Tank farm configurations vary according to the preferences and requirements of the participants. In some cases, all fuel storage is located within a single enclosure and is managed by a single entity. In other cases, several diked enclosures are constructed within a single facility, with each enclosure containing fuel owned by one participant and each participant responsible for the operation of its own diked cell. Other variations have also been devised.

Construction costs for the tank farms can vary significantly depending on project location, site conditions, size of tank farm, and other factors. For preliminary planning purposes, AEA uses a rule of thumb of $7.20 per gallon. Realistically, these costs vary significantly, with construction of larger tank farms costing less per gallon and smaller tank farms costing more.

8.2.4.1 Comparison of Force Account and Conventional Bid Construction Cost

Limited data are available regarding the cost of force account construction as compared to conventionally bid projects in rural Alaska. The VSW program has completed two comparisons of force account and conventional bid costs for projects in rural Alaska in recent years. One of the analyses compared a sewage lagoon upgrade project to an airport erosion control project in Hooper Bay, and the other provided a justification for using force account construction for a boardwalk construction project in Chefornak. Copies of both of these analyses are included in Appendix B.

In general, it was assumed that material and freight costs would be the same for either type of project, although opportunities for cost savings may be more likely with the force account method since there is more flexibility and opportunity for consolidation with other projects. Generally, construction contractors own or lease their equipment, so if it is assumed that the equipment is leased in both cases, then equipment costs are similar. Additionally, if the community has some equipment of its own, it would likely be leased to the project regardless of the contracting method. Therefore, the primary difference between force account and conventionally bid projects is labor cost. Local labor forces often require training, resulting in increased costs. However, these costs may be offset by the reduced cost resulting from not having to provide room and board for local workers.

Table 8-2 summarizes wage rates using the prevailing method and force account approach (as provided in the VSW Chefornak analysis, labor rates for rural Alaska force account, and prevailing wage rates for Alaska as outlined in AS36.05, Wages and Hours of Labor). As shown in Table 8-2, wage rates for a conventionally bid project are more than twice as high as those for force account construction. In addition to the direct labor savings, payroll taxes are reduced. Force account construction does not include profit, overhead, or bonding costs, resulting in additional savings. Overhead and profit costs may be as much as 15 to 25 percent of total project costs, with bonding and insurance adding 8 to 10 percent.

Table 8-2. Comparison of Prevailing Wages and Force Account Wages

Labor Category	Wage ($ per Hour)	
	Force Account, Typical Range	Minimum per Alaska Statute
Foreman	18 – 20	36.30
General Laborer	12 – 14	32.64
Lead Carpenter	16 – 18	36.30
Carpenter Helper	14 – 16	32.64
Housekeeper/Janitor	10 – 12	24.07
Cook	10 – 12	26.71
Equipment Operator	20 – 22	38.17

Other costs savings on force account projects include reduced requirements for room and board and limited or no requirements for camp facilities. Mobilization costs for most personnel, including time and expenses, are eliminated. The onsite superintendent acts as an inspector, eliminating the need for a full-time construction inspector, thereby reducing construction management costs as well. AIDEA has identified a limited number of qualified field superintendents in Alaska. This constraint limits the number of projects that can be conducted under current practices.

8.3 Analysis of Strategies

This subsection presents the analysis of alternative design and construction methods for bulk fuel facilities. The goal of this evaluation was to determine the effectiveness of the existing systems and to evaluate whether there are any system components that could be modified to make better use of project funding. The Phase 1 report outlined several options for design, construction, and operation of the bulk fuel tank farms. The options considered are discussed in the following subsections.

8.3.1 Option 1: State Manages Construction and Owner Constructs with Force Account Labor (Current Model)

Overview. This option allows the local government to hire most of the required project labor from the local community on force account. Training is often provided to local workers, which may promote future economic development in these communities. After completion of the project, workers familiar with the facility and equipment are available for long-term O&M.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative, as compared with **conventional construction contracting.**

Cost Impacts (Compared with Conventional Construction Contracting)

1. Davis-Bacon wages are not required as long as a local government entity is the owner, which helps to reduce construction costs.
2. The requirement for housing of out-of-town workers is minimized, resulting in lower costs.
3. Onsite quality control is provided by a foreman approved by the State of Alaska. A full-time inspector is not required, resulting in lower construction management costs.
4. Design costs are lower since a complete bid package with technical specifications is not required. Construction documents include design drawings with performance specifications included on the drawings.
5. The option allows for design changes at any time without a change order.
6. The option allows for standardization of parts and equipment since the state handles materials procurement.
7. Costs may be more difficult to control when unanticipated conditions are encountered.
8. The option requires more involvement by the state, including approving payroll, completing procurement activities, and managing staff, possibly resulting in higher overall management costs than other contracting methods.

Schedule Impacts

1. If inadequate or unskilled labor resources are available in the community, and if significant training is required for workers, the construction effort may take longer than a conventionally bid project.

2. There are a limited number of qualified field superintendents and projects can be delayed because of this constraint.
3. Since the project is not advertised for bids, the construction can often begin as soon as project funding is secured.

Conclusion. The current model has been developed by AEA over the years. Although there have been problems, effective solutions have been developed and refined and the current program has resulted in successful projects in many communities. The force account construction method provides opportunities for economic development in these communities by providing new jobs and skills. Although these types of opportunities may also be able to be provided through more conventional, contractor-built projects, it appears that the force account method is becoming a proven and cost-effective method of construction in rural Alaska. Additionally, rural Alaska residents are likely to take pride in ownership of projects on which they have participated in the construction.

The use of construction management firms under contract to the state or to the owner (or community) has been suggested as an approach to address the problem of a limited number of qualified field superintendents. This approach could be used in Option 2 as well if the state were faced with a shortage of qualified personnel.

8.3.2 Option 2: State Manages Design and Contractor Constructs, Contractor Selected Through Conventional Competitive Bid Process

Overview. This option includes construction by a contractor hired through the conventional bid process, in which bids are advertised and general contractors bid for the work, either on a work item or lump sum basis. Historically, State of Alaska agencies have used this contracting method on many public projects. There is limited benefit to the local economy unless local hire requirements are included in the contract documents. As with the current model (force account), local hire would likely occur primarily with unskilled or moderately skilled workers such as laborers and equipment operators, depending on skill availability within the community. There is no legal minimum or maximum percentage of local hire that can be required by contract. Additionally, although some communities have facilities where construction workers may be housed, many small communities require mobilization of a camp facility, resulting in little increase in economic activity during the construction period.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative.

Cost Impacts

1. Costs are generally easier to control unless conditions are encountered that result in significant change orders. Bids can either be on a lump sum or unit cost basis, allowing for flexibility in controlling costs. Unit price bids allow for items to be added or deleted at a set price.
2. Liability for construction is borne by the contractor. However, this results in increased construction costs as the contractor must bear the cost of insurance and warranties.
3. The facility can be warranted for a period (1 to 2 years is typical). This can result in cost savings if warranty issues arise; however, the cost of providing the warranty is borne by the project whether or not warranty work is required.

4. Few new skills are learned by the community unless local hire requirements are included in the contract documents. Although not directly related to capital costs, the long-term operation of the facility can be affected if skilled workers are available to maintain it.
5. There is less involvement by the state administratively, resulting in lower direct administration fees.
6. A full-time construction inspector may be required, resulting in increased costs.
7. Higher wage rates are required because of the requirement that Little Davis Bacon rates be paid for publicly contracted projects per AS 36.05.010.

Schedule Impacts

1. The contractor selection process can increase project time. The significance of this impact would depend on the project timing, including consideration of funding availability, barge/airline schedules, and the summer construction season.
2. Procurement is handled by the contractor rather than the state. This may affect the schedule if adequate time is not available to complete contractor procurement in accordance with state policies and subsequently allow the contractor to purchase and mobilize materials before the targeted construction start date. With force account construction, the state is able to procure and mobilize large items such as tanks and piping before the design is finalized, allowing construction to begin very soon after the construction drawings are completed.

Conclusion. Publicly bid construction is a proven and acceptable method of contracting and may be an effective method of lowering construction costs on bulk fuel projects. This would be especially effective if inadequate resources are available within a particular community to complete force account construction, or if especially difficult construction is required due to site conditions or project design. Local hire clauses can be included so that economic opportunities and training similar to those provided by force account construction are available to the community.

8.3.3 Option 3: Request Design-Build Proposals from Private Contractors for Tank Farm Upgrades for Individual Communities

Overview. This option would include preparation of a preliminary (35 percent) design, which would then be used to obtain bids for final design and construction through a publicly bid process. Several issues would need to be finalized before proceeding to final design such as project ownership, site selection, and site control.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative.

Cost Impacts

Project management costs may be less, as the contracting agency has to coordinate with only one contractor rather than with the city, a design contractor, a construction management contractor, and others.

1. Costs may be higher than in conventional force account construction projects due to higher labor rates, overhead costs, and others, as discussed in Option 2.
2. The contracting agency can prequalify contractors, resulting in lower contract solicitation costs.

3. Design-build projects allow more flexibility in completing design changes as the project progresses, possibly resulting in fewer change orders and lower construction costs.
4. Design-build process allows less detail to be provided in the bid package, resulting in overall lower design costs.
5. A full-time construction inspector may be required, resulting in increased costs.
6. This approach could be used for either force account or conventionally bid projects. For example, the project could be bid as a typical construction contract with no local involvement, or the design-build contract could be written such that the work is completed by force account methods, where the contractor takes a project management role similar to that currently fulfilled by AEA.

<u>**Schedule Impacts**</u>

1. Assuming that funding is available for final design and construction, it is possible that final design and construction could be completed under an accelerated schedule, possibly within the shortest timeframe of any of the alternatives.

Conclusions. The design-build concept is especially promising not only for cost savings related to streamlining design and construction, but also for promoting community participation if the project is implemented correctly. Design-build of a single tank farm should be completed and evaluated for success before implementing any design-build program for multiple communities (See Option 4).

8.3.4 Option 4: Request Proposals from Private Contractors to Design and Construct Upgrades for Selected Groups of Villages

Overview. This option is similar to Option 3 in that the design-build process is implemented. The difference is that the design-build process would be applied to a group of communities, most likely located in one geographic area.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative.

<u>**Cost Impacts**</u>

1. General cost impacts would be similar to those discussed under Option 3—Design-Build of a Single Tank Farm.
2. Additional cost savings may be realized during procurement because of the increased volume of materials. For example, 20 tanks would likely be purchased at a lower unit cost than would be paid for 5 tanks.
3. Problems in individual communities may affect other communities. For example, if issues arise during permitting or if the location of the tank farm site changes, construction in the other communities under the contract may be affected. This problem can be minimized by having community resolutions for site selection and other key decisions and by having a separate consultant prepare the 35 percent design. However, experience suggests that other problems and issues often arise that may affect siting or construction issues as the final design and construction phases progress.

Schedule Impacts

1. Schedule impacts include possible acceleration of schedule that may occur during the design-build process.
2. The construction schedule for one community may be affected by other communities if problems arise.

Conclusions. As noted under Option 4, implementation of a design-build project for bulk fuel tank farms is worthy of consideration. Bundling bulk fuel projects for multiple communities should be approached with caution as problems in one community can affect activities in another community, and may also result in change orders, thereby increasing the contract price. It is more advisable to try a design-build project in one community to evaluate success before attempting the process in multiple communities. If communities are constructed as a group, it would be most advisable to select communities in the same geographic area.

8.3.5 Option 5: Request Proposals from Qualified Private Entities to Design, Build, Own, and Manage New Consolidated Tank Farm(s)

Overview. Examples of potential respondents include wholesale fuel distributors, utility companies, regional or village corporations, and private businesses. This option would allow a private entity to use state funds to design and build a new tank farm, and then operate the tank farm. The state would have a management oversight role throughout the design and construction phase of the project, but would likely have less control over decisions than with the current model.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative.

Cost Impacts

1. The tank farm owner is responsible for the entire project, from the planning through the operational phase, possibly resulting in cost savings. Having a private entity manage the tank farm during the operational phase may result in higher fuel costs to rural Alaskans since the tank farm owner may be operating for profit. Most Native corporations and communities currently operating tank farms in rural Alaska have a goal of providing the cheapest fuel possible to local residents.
2. Private entities would be subject to Little Davis Bacon rates, resulting in increased cost over force account rates.
3. A full-time construction inspector may be required, resulting in increased costs.
4. Cost overruns may occur if the contractor is not specifically qualified to complete design and construction of bulk fuel tank farms in rural Alaska.

Schedule Impacts

1. Less oversight and control over the project by the state lead to schedule delays due to lack of planning and poor management if the tank farm owner is not qualified to manage this type of project.

Conclusions. The design-build-manage alternative warrants further consideration. Research into whether qualified and interested entities exist to undertake this effort should be completed as the next stage of evaluation of this alternative. The key to the success of this option would be to identify a contractor that is well qualified to design, construct, and operate a tank farm in rural Alaska.

8.3.6 Option 6: Existing Tank Farm Owners Manage, Design, and Construct Their Own Upgrades or Replacement Projects

Overview. This option allows the local government, school, or other entity to have control over all aspects of the project. Where AEA has worked toward standardization of parts and materials, this option would likely lead toward more diverse designs, as AEA would have a lesser role in the project and less control over design aspects. Additionally, many small rural communities do not have the existing infrastructure to manage these types of projects without significant oversight and direction from state agencies.

Analysis. The following items describe cost impacts and scheduling impacts of this alternative.

Cost Impacts

1. The tank farm owner is responsible for the entire project, from the planning through the operational phase. Lack of experience in managing turnkey projects may lead to cost overruns.
2. Since each owner maintains its own facility, there would be less opportunity for consolidation of bulk fuel facilities, which would likely result in overall increased capital cost for each community.
3. Lack of standardization of parts may lead to difficulties during the operational phase. AEA currently maintains an inventory of parts that can be shipped to communities on an emergency basis if the need arises.
4. Less oversight of project funds by a state agency could result in cost overruns due to inexperience in managing this type of design and construction project. Lack of knowledge of industry standards could also affect project quality and cost.
5. If the owner is a private organization rather than a municipal entity, Little Davis Bacon rates would apply to force account construction, similar to a conventionally bid project.
6. A full-time construction inspector may be required, resulting in increased costs.

Schedule Impacts

1. Less oversight and control over the project by the state could lead to significant schedule delays due to lack of planning and poor management if the tank farm owner is not qualified to manage this type of project.

Conclusions. It is unlikely that many of the existing tank farm owners are interested in or have the resources to design and construct new tank farm facilities without significant guidance from a public entity. There is much risk in implementing this option unless the state can be assured by the tank farm owner that the owner has the resources and qualifications to successfully manage the project. Therefore, this alternative should be eliminated from consideration.

8.4 Conclusions and Recommendations

The current AEA practice includes using subcontractors to complete design and force account labor to complete the construction phase of bulk fuel storage projects. This method of program management has proven successful in the past, is comparable in cost to other methods of contracting based on the information provided in the ICRC report, and often provides training and new skills for rural Alaskans. Other alternatives to project management as discussed in this report are also likely to be viable and cost-effective, and should be considered for implementation for comparison with the current force account process.

The two options that are most likely to succeed and provide a cost-effective construction project include competitively bidding the construction, which is the typical practice of most state agencies in accordance with state procurement policies, and completing a competitively bid or pre-qualified design-build project in a community. The current process (force account) is designed to promote community involvement and education, develop standardization of parts throughout rural Alaska bulk fuel tank farms, provide training for local community members, and keep project funds in the rural community. These aspects of project development should be considered in any alternative contracting method implemented.

As noted throughout this section, there have been very little data compiled to date on the cost of force account compared with conventional contracting methods, and there have been no projects specifically targeted for a comparison. It is suggested that these different contracting methods be implemented in conjunction with force account in separate communities with similar tank farms so that a more accurate quantitative cost comparison of the various contracting methods can be performed. If proven successful, either of these alternative methods may be implemented in more than one community, as described in Option 5.

9 Bulk Fuel Storage: Financing of Tank Farm Upgrades

9.1 Introduction

Summary

The results of this preliminary analysis suggest that:

- AEA has made considerable efforts and achieved considerable success in consolidating bulk fuel storage facilities when upgrading tank farms in rural Alaska.
- Bulk fuel storage facilities in rural Alaska are funded primarily by state and federal funds. Local contributions are obtained in few cases and are a small part of the total cost of tank farm upgrades.
- The impact on fuel prices of requiring owners of bulk fuel storage facilities to pay a portion of construction costs could be significant. Fuel costs will increase by 8 to 14 cents per gallon if a retailer takes out a 10-year loan for 10 percent of its share of the capacity costs, at an interest rate of 10 percent per annum. Extending the loan period to 20 years would mitigate this effect.

These impacts justify continued study of tank farm financing in the next stage of the Rural Energy Plan, Phase 2B.

Alaska's rural energy is highly dependent on diesel generation. Consequently, bulk fuel storage facilities are an integral part of energy provision. In recent years, AEA has exerted significant efforts to upgrade tank farms throughout rural Alaska. The primary objectives of this analysis are to identify alternative sources of financing for tank farm upgrades, to evaluate how these upgrades currently are being financed, and to estimate the impact of financing alternatives on fuel prices and consumers. Secondary objectives are to understand why and how rural communities arrived at very different bulk fuel storage facilities. In pursuit of these objectives, this subsection examines three aspects of the AEA upgrade process:

- As a part of its efforts to upgrade tank farms, AEA has attempted to consolidate the storage facilities of various tank owners into single tank farms. The success of these efforts is examined for several communities that have undergone AEA upgrades. Differences in fuel storage requirements among the communities, differences in financing available to the tank owners, differences in ownership interests, and community differences that contributed to the differences in fuel storage facilities are examined in Subsection 9.2.
- Financial contributions to the cost of tank farm development and construction are evaluated (Subsection 9.3) to determine the degree to which various public and private interests have paid a share of construction expenses.
- The effect on fuel prices of requiring entities to pay a share of the construction costs is evaluated (Subsection 9.3). The analysis assumes that the full cost of the payment of the share of construction costs is passed on to fuel purchasers over the likely period of a loan used to fund the payment.

To examine these issues, the bulk fuel storage facilities in seven rural Alaska communities—McGrath, Atmautluak, Arctic Village, Buckland, Noorvik, Emmonak, and Selawik—were reviewed. These villages were chosen because of differences in their bulk fuel storage facilities and because each has recently undergone or is currently undergoing a tank farm upgrade.[43] Most of the villages have several different tank owners, some of whom own independent tank farms and others of whom own tanks in consolidated farms.[44]

This section differs in both purpose and scope from the other sections of this report. Consequently, the section does not lend itself to the structure adopted elsewhere.

9.2 Existing Conditions

9.2.1 Village Cases

9.2.1.1 McGrath

McGrath is a second-class city with 423 residents. Founded in 1907 on the Kuskokwim River, directly south of the confluence with the Takotna River, McGrath is 221 miles northwest of Anchorage and 269 miles southwest of Fairbanks.

McGrath Light & Power provides electrical power to the city with diesel generation. Several organizations own fuel tanks in the city, including the Federal Aviation Administration (FAA), the U.S. Fish and Wildlife Service (USFWS), the Alaska Department of Natural Resources (DNR), ADOT&PF, and the Alaska Department of Fish and Game. A complete list of the operational tank farms in McGrath appears in Table 9-1.

Two tank farm upgrades have been undertaken recently in McGrath, and a third is under consideration:

- In 1995, McGrath Power & Light upgraded its tank farm. McGrath Power & Light and the Alaska DOE jointly undertook the project. Table 9-2 identifies funding contributors for the upgrade. The cost was approximately $205,000, $175,000 of which was paid with DOE grant funds. McGrath Power & Light provided the remaining $30,000 (approximately 15 percent) of the funding with equity. No loans were used. Since McGrath Power & Light financed a portion of the project, it is likely that the company's contribution is reflected in its current prices. The consolidated tank farm and its tanks are wholly owned by McGrath Power & Light.[45]
- The city upgraded its tank farm more recently, with no consolidation of tanks from other farms in the community. AEA has little information about this upgrade because the project was undertaken without AEA assistance.
- The school tank farm is also in need of an upgrade. McGrath Power & Light is currently evaluating the development of an expanded waste heat facility that would supply heat to the school and other buildings. Since this would substantially affect the school's fuel requirements, the upgrade of the bulk fuel storage facility is being postponed pending the decision on the waste heat project.

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[43] Since changes in tank farm design occur often during construction phases, the analyses for communities in which tank farm upgrading is currently underway should be considered tentative.

[44] For example, McGrath has several tank farms throughout the city, and all of these farms contain tanks owned by a single owner. Atmautluak has two tank farms in the village. One is a consolidated tank farm with three owners, and the other contains a single tank.

[45] Although the DOE suggested development of a community tank farm, McGrath Power & Light resisted these efforts because its management felt that cooperative efforts would be complicated due to individualism of community members (Propes, 2000).

Table 9-1. Operational Tank Farms in McGrath

Tank Farm Owner [a]	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
FAA	7 [b]	[c]	[c]	Barge to truck
DNR	2	20,000 [d]	NA	Barge to truck
DNR	3	6,200	4,100	Barge to truck
ADOT&PF	4 [b]	21,700	1,000	Aircraft or barge to truck
KSKO Radio	2	10,000	NA	Barge to truck
Ben Magnuson	7	80,400	67,800	Aircraft and barge
Alaska Commercial Store	1	1,100	NA	Barge to truck
ADF&G, Public Safety Division	2	7,200	NA	Barge hose or barge to truck
USFWS	5	2,500	NA	Barge to truck
Camai Center (McGrath Native Village)	2 [e]	2,000	NA	Barge to truck
Catholic Church	1	1,200	NA	Barge to truck
McGrath Power & Light	4	223,400	NA	Barge
City of McGrath [f]	5	43,200	5,400	Barge
Total	**39**	**411,900**	**78,300**	

Source: AEA, 2000.
[a] Each tank farm is individually owned.
[b] Two tanks are belowground.
[c] No data available
[d] Aviation fuel
[e] One tank is belowground.
[f] McGrath also has four tank farms that are out of service and are not included in this analysis.

Table 9-2. McGrath Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	Organization	Amount ($)	Percent of Total
Federal Government	-	0	0
State Government	DOE	175,000	85.4
Private	McGrath Power & Light	30,000	14.6
Total		**205,000**	**100.0**

Source: AEA, 2000.

9.2.1.2 Atmautluak

Atmautluak is a village of 296 people and is situated on the west bank of the Pitmiktakik River in the delta of the Kuskokwim River. The village is approximately 20 miles northwest of Bethel.

The village's electric utilities are provided by the Atmautluak Traditional Council. Retail fuel sales in the village are made by the village corporation. The only other owner of bulk fuel storage is the regional school district, which operates the local schools.

Table 9-3 identifies the operational tank farms and tank owners in Atmautluak. A new 17-tank tank farm was constructed by a DOE consolidation effort beginning in August 1996 and completed in fall 1998. The consolidation brought together tanks of three owners, Atmautluak Traditional Council, Lower Kuskokwim School District, and Atmautluak Limited, into a single farm. Under the terms of the consolidation agreement, each owner is responsible for maintenance and operation of its own tanks and part of the facility. The Traditional Council is responsible for common parts of the facility.

Each tank owner retained its tanks in the consolidation, with two exceptions. The Traditional Council dismantled one 5,750-gallon tank and retained two 24,000-gallon tanks. The school moved all of its tanks to the consolidated farm and added a single 4,000-gallon tank on location at the school to supply its heating system. This single tank is the second of the village's two tank farms.

Table 9-4 identifies the three funding contributors for the consolidated tank farm in Atmautluak. The Alaska Department of Education contributed $887,202. HUD contributed $500,000 through an Indian Community Development Block Grant (ICDBG),[46] and the Lower Kuskokwim School District contributed $29,000.[47]

Table 9-3. Operational Tank Farms in Atmautluak

Tank Farm and Owners	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
Atmautluak Traditional Council	2	48,000	NA	Barge
Lower Kuskokwim School District	9	65,200	NA	Barge
Atmautluak Limited	7	46,000	20,000	Barge
Total	**18**	**159,200**	**20,000**	

Source: AEA, 2000.

Table 9-4. Atmautluak Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	**Organization**	**Amount ($)**	**Percent of Total**
Federal Government	HUD [a]	500,000	35.3
State Government	ADEC, Alaska Department of Education	887,202	62.6
Schools	Lower Kuskokwim School District	29,000	2.0
Native Village	-	0	0
Native Corporation	-	0	0
Total		**1,416,202**	**100.0**

Source: AEA, 2000.
[a] HUD contribution was made through an ICDBG to the Native Village of Atmautluak.

[46] Although these grants are often considered a contribution of the party receiving the grant, this study is examines the origin of funds. Therefore, all grants are considered contributions of the granting institution, rather than the recipient.

[47] The school district contribution should not be considered a local contribution since the state government funds rural school districts. The state granted $1.5 million to the Lower Kuskokwim School district to fund bulk fuel storage upgrades. Whether the district used money from this grant to fund this particular project is not known.

9.2.1.3 Arctic Village

Arctic Village, with 117 residents, is on the east fork of the Chandalar River, approximately 100 miles north of Fort Yukon. Arctic Village is unique among the villages analyzed in that all fuel is flown in. The village has five bulk fuel storage facilities, three owned by the village council, one owned by the school district, and one owned by USFWS. A complete list of operational tank farms in Arctic Village appears in Table 9-5.

The village is currently undergoing a tank farm consolidation. Both the Village of Arctic Village and the Yukon Flats School District will participate. The development of the new consolidated facility is intended to move all storage to a central location in the village. The conceptual design of the bulk fuel facility is complete. The full design and construction of the pad are to be completed before this winter. Storage capacities are similar to those in other villages, where the school tanks typically have capacity that is twice the school's anticipated annual usage, and others in the village have capacity approximately equal to their annual throughput.

Funding for the consolidation project has been obtained and is entirely from grants. The Denali Commission is providing $1,120,000, AEA $62,116, and ADEC $225,000. This funding will also pay for the design and construction of the new powerhouse. Table 9-6 identifies the contributors to the funding for the consolidated tank farm in Arctic Village.

Table 9-5. Operational Tank Farms in Arctic Village

Tank Farm [a]	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
Yukon Flats School District	10	31,000	NA	Aircraft to truck
Arctic Village Electric Company (Village Council)	2	6,000	NA	Aircraft
U.S. Fish and Wildlife Service	1 plus 11 drums	4,105[b]	NA	Aircraft
Village Gas Sales (Village Council)	1	NA	2,100	Aircraft to tank, tank is skidded to village
Village Council Office	2 plus 1 drum	5,455	NA	[c]
Total	**16 plus 12 drums**	**46,560**	**2,100**	

Source: AEA, 2000.
[a] Each tank farm is individually owned.
[b] Aviation fuel
[c] Information unavailable

Table 9-6. Arctic Village Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	Organization	Amount ($)	Percent of Total
Federal Government	Denali Commission	1,120,000	79.6
State Government	AEA	62,116	4.4
	ADEC	225,000	16.0
Schools	-	0	0
Native Village	-	0	0
Total		**1,407,116[a]**	**100.0**

Source: AEA, 2000.

9.2.1.4 Buckland

Buckland is a second-class city with a population of 428. The city is on the west bank of the Buckland River, about 75 miles southeast of Kotzebue. The City of Buckland operates the local power plant, providing electric power to the community. The Native Village of Buckland operates the city's retail fuel sales facility. The village has seven tank farms. Three owned by the city are used for heating municipal buildings and facilities (including the washeteria), heating water, and generating power. The Native village owns one tank farm for retail fuel sales. The other three farms are owned individually by the school district, the Alaska Army National Guard, and ADOT&PF. The tank farms are more fully described in Table 9-7.

Consolidation of fuel storage is being planned for Buckland. The projected cost of consolidation is $2.2 million, to be funded entirely by the Denali Commission. Consolidation is intended to address several environmental concerns related to fuel storage in the city. One of the city's tank farms and the Native village's tank farm frequently are threatened by flooding. The Native village's tank farm and the school district's tank farm both require more than 500 feet of hosing from the barge to their headers for filling. The filling pipe at one of the city's tank farms has several leaks.

The ADOT&PF tank is new and was purchased to supply fuel to heat the airport equipment shop.

Table 9-8 identifies the contributors to the funding for the consolidated tank farm in Buckland. The City of Buckland, the Native Village of Buckland, and the Northwest Arctic Borough School District will participate in the consolidation. The consolidation of storage is currently being planned, so the exact capacities of the different tank owners are uncertain. Currently, all tank owners have farms with capacity equal to their annual throughput, with the exception of the school, which maintains capacity in approximately twice its annual consumption. These capacities are consistent with AEA recommendations, so it may be expected that the different tank owners remain relatively close to their present capacities. The new farm will be on city-owned property.

Table 9-7. Operational Tank Farms in Buckland

Tank Farm [a]	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
Native Village of Buckland	11	99,400	52,400	Barge
City of Buckland	2	14,800	NA	Barge
City of Buckland	2	16,100	NA	Barge
City of Buckland	2	44,800	NA	Barge
Northwest Arctic School District	5	62,500	NA	Barge
Alaska Army National Guard	2	4,600	NA	Barge
ADOT&PF	1	2,700	NA	[b]
Total	**25**	**244,900**	**52,400**	

Source: AEA, 2000.
[a] Each tank farm is individually owned.
[b] Information unavailable

Table 9-8. Financing of Buckland Tank Farm Development: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	**Organization**	**Amount ($)**	**Percent of Total**
Federal Government	Denali Commission	2,200,000	100
State Government	-	0	0
Schools	-	0	0
Native Village	-	0	0
Total		**2,200,000**	**100**

Source: AEA, 2000.

9.2.1.5 Noorvik

Noorvik, a second-class city with 632 residents, is on the bank of the Nazuruk Channel of the Kobuk River approximately 45 miles east of Kotzebue. AVEC operates the local electric utility. The city has two retail sales facilities, one entirely private and the other operated by the Native village. The city and the school district also operate bulk fuel storage facilities. Noorvik has six operational tank farms, which are listed in Table 9-9.

Several tanks in the city have multiple code violations. Tanks at the private retail outlet have active leaks. Some of the school's tanks are in very poor condition; some are in the flood plain. The tanks used for retail sales by the Native village are in very poor condition. All of these shortcomings have contributed to a decision to upgrade and consolidate many of the tanks in Noorvik into a single farm. The consolidation is underway and might be completed by the end of this construction season. The Native Store (of the Noorvik Native Community), the City of Noorvik, the Northwest Arctic Borough School District, and Morris Trading Company will participate, and the farm will be on Noorvik Native Community property. The consolidation will include storage for retail sales facilities and the city. Ownership is set out in Table 9-10. Each tank farm is individually owned.

The total project cost was $2.65 million. Funding came from a variety of sources, as shown in Table 9-11. The EPA contributed $900,000. An ICDB grant for $300,000 from HUD and a $200,000 grant from the Denali Commission were used. The city indirectly contributed $200,000 through a Community Development Block Grant (CDBG). Morris Trading Company, the private retail fuel outlet contributed $50,000.

Table 9-9. Operational Tank Farms in Noorvik

Tank Farm [a]	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	**Gasoline**	
AVEC	17	145,700	NA	Barge
Northwest Arctic Borough School District (High School)	6	52,200	NA	Barge
City of Noorvik	12	30,900	NA	Barge
Northwest Arctic Borough School District (Elementary School)	5	42,700	NA	Barge
Morris Trading Post	3	35,200	23,800	Barge
Noorvik Native Store	14	66,000	64,500	Barge
Total	**57**	**372,700**	**88,300**	

Source: AEA, 2000.
[a] Each tank farm is individually owned.

Table 9-10. Tank Ownership in the Consolidated Tank Farm in Noorvik

Tank Owner	Capacity (Gallons)	
	Diesel	Gasoline
City of Noorvik	44,600	NA
Northwest Arctic Borough School District (High School and Elementary School)	91,400	NA
Morris Trading Post	45,800	32,300
Noorvik Native Store (Noorvik Native Corporation)	80,100	72,300
Total	**261,900**	**104,600**

Source: AEA, 2000.

Table 9-11. Noorvik Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	Organization	Amount ($)	Percent of Total
Federal Government	Denali Commission	300,000	11.3
	EPA	900,000	34.0
	HUD [a]	700,000	25.4
State Government	ADEC, Alaska Department of Education	500,000	18.9
	AEA	200,000	7.5
Schools	-	0	0
Municipal Government	-	0	0
Private	Morris Trading Company	50,000	1.9
Total		**2,650,000**	**100.0**

Source: AEA, 2000.
[a] HUD contribution was through a $200,000 CDBG to the City of Noorvik and a $500,000 ICDBG grant to the Noorvik Native Community.

9.2.1.6 Emmonak

Emmonak, a second-class city with a population of 818, is located at the mouth of the Yukon River, 10 miles from the Bering Sea, approximately 120 miles northwest of Bethel. Electric power in the city is provided by AVEC. The city has 11 tank farms owned by several different interests including the utility, city, the school district, the village corporation, a private retail seller, and a local air carrier. A full list of tank farms in the city appears in Table 9-12.

Some of the tank farms in Emmonak are undergoing consolidation. Several farms are in the flood plain and some of the tanks are leaking or damaged. Consolidation should rectify some of these problems. The planned upgrade will consolidate tanks belonging to the City of Emmonak and Emmonak Corporation, the local Native corporation. The tank farm will be on Emmonak Corporation land. Storage is projected to equal annual throughput for both participants. The fuel capacities of the owners participating in the consolidated tank farm are shown in Table 9-13.

The consolidation is expected to cost $2.44 million. This amount is subject to change as development proceeds. Funding for the consolidation is being received from a variety of sources. A HUD ICDBG grant for $500,000 and a HUD CDBG grant for $200,000 are being used. The Denali Commission is contributing approximately $900,000. The EPA is contributing $400,000 (Gerrick, 2000). Emmonak Corporation is contributing $215,000 through a Power Project Fund Loan from AIDEA. The loan is for a term of 20 years at an interest rate of 5.4 percent per annum. Under these terms, the corporation's semiannual payments will be $8,855.76. AEA is also contributing $325,000 to the project (McMillen, 2000). Table 9-14 identifies the contributors to the funding for the consolidated tank farm in Emmonak.

Table 9-12. Operational Tank Farms in Emmonak

Tank Farm Owner	No. of Tanks	Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
AC Company Store	2	20,000	NA	Barge
AVEC	21	172,247	NA	Barge
City of Emmonak	3	11,300	NA	Barge
City of Emmonak	2	28,000	NA	Barge
City of Emmonak	4	40,000	NA	Barge
City of Emmonak	6	52,200[b]	[b]	Barge
Emmonak Corporation	8[a]	380,000[b]	[b]	Barge
Emmonak Corporation	4	41,148	NA	Barge
Grant Air Service	6	133,000	NA	Barge
Lower Yukon School District	4	128,000	NA	Barge
Lower Yukon School District	5	40,000	NA	Barge
Total	**57**	**1,045,895**	[b]	

Source: AEA, 2000; Gerrick, 2000; McMillen, 2000.
[a] Each tank farm is individually owned.
[b] One tank is not being used.
[c] The amount of fuel in each fuel type is not accounted for.

Table 9-13. Tank Ownership in the Consolidated Tank Farm in Emmonak

Tank Owner	Capacity (Gallons)	
	Diesel	Gasoline
City of Emmonak	50,000	10,000
Emmonak Corporation	155,000	205,000
Total	**205,000**	**215,000**

Source: AEA, 2000.

Table 9-14. Emmonak Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	**Organization**	**Amount ($)**	**Percent of Total**
Federal Government	Denali Commission	600,000[a]	26.8
	EPA	400,000	17.9
	HUD [b]	700,000	31.3
State Government	AEA	325,000	14.5
Municipal Government	-	0	0
Native Corporation	Emmonak Native Corporation	215,000[c]	9.6
Total		**2,240,000**	**100.0**

Source: AEA, 2000.
[a] The Denali Commission has committed to a $600,000 contribution at this time. The exact amount of the Denali Commission contribution, however, may differ.
[b] HUD contribution was through a $500,000 ICDBG to Emmonak Native Corporation and a $200,000 CDBG to the City of Emmonak.
[c] The contribution of Emmonak Native Corporation is through a Power Project Fund loan from AIDEA.

9.2.1.7 Selawik

Selawik, a village with 767 residents, is at the mouth of the Selawik River where the river empties into Selawik Lake, about 70 miles southeast of Kotzebue.

AVEC provides electric power to the village. Four other entities own bulk fuel storage facilities in the village: the school, the traditional council, a private store, the Alaska National Guard, and ADOT&PF. Retail sales are handled entirely by the traditional council, because the private store uses its storage capacity strictly for onsite heating. A summary of the village bulk fuel storage appears in Table 9-15.

The circumstances at Selawik differ substantially from those of other villages considered. The community, however, is developed on three islands. Limitations on suitable ground as well as the difficulty of developing a distribution system among the different users have prohibited consolidation of bulk fuel storage in the community. Consequently, opportunities for consolidating fuel storage in the village are very limited. The tanks at the Selawik IRA store were recently upgraded. The project cost was approximately $1.175 million. Approximately $400,000 of the funding for the upgrade was from AEA. The remaining funding (approximately $775,000) was from the Native Village of Selawik and was provided through a grant from the Administration for Native Americans (ANA) of the U.S. Department of Health and Human Services (HHS).

Table 9-15. Operational Tank Farms in Selawik

Tank Farm Owner [a]	No. of Tanks	Fuel Capacity (Gallons)		Delivery Mode
		Diesel	Gasoline	
AVEC	16	138,900	NA	Barge
Northwest Arctic Borough School District	10	92,900	NA	Barge
Selawik IRA Store	11	146,500	103,500	Barge
Rotman Store	2	9,800	NA	[b]
IRA/HUD Housing Complex	2	26,000	NA	Barge
Alaska National Guard	3	8,500	NA	Barge
ADOT&PF	1	2,500	NA	[b]
Total	**45**	**425,100**	**103,500**	

Source: AEA, 2000.
[a] Each tank farm is individually owned.
[b] Information not available

Table 9-16. Selawik Tank Farm Development Financing: Amount and Percentage by Type of Contributor

Contributor		Contribution	
Type	Organization	Amount ($)	Percent of Total
Federal Government	HHS	776,255	66.0
State Government	AEA	399,000	34
Native Village	Native Village of Selawik (ANA Grant)	[a]	[a]
Total		**2,440,000**	**100.0**

Source: AEA, 2000.
[a] The HHS contribution is through a grant from ANA to the Native Village of Selawik.

9.3 Background

The seven villages described above are very different from one another. In most of the villages, tank owners have agreed to move their tanks into consolidated tank farms. In two villages—Selawik and McGrath—all tanks are in independently owned tank farms. These two villages have not consolidated tank farms for different reasons.

- In Selawik, which is located on a cluster of three islands, development of a consolidated tank farm is strictly limited by the availability of suitable land with adequate area, as well as by concerns about routing fuel pipelines beneath bridges that connect the islands.
- In McGrath, community composition appears to be a factor that inhibits the potential for tank farm consolidation. Several institutions have bulk fuel storage facilities, each for its own uses and interests. Financing considerations could contribute to the difficulty of consolidating. Requirements of various funding sources could add to conflicts among tank owners. McGrath, founded in 1907, is relatively old by Alaska standards. The economy is relatively well developed, with more than 60 businesses licensed by the state. Where business interests are relatively well established, the ability to direct varying interests toward consolidation is likely to be limited. The

median household income, more than $35,000, is the highest of the communities examined. This relative prosperity is likely to make the various interests less sensitive to the need for pooling of resources for cost savings.

Although in any community tank farm consolidation may be resisted, the different interests in McGrath are less likely to be aligned than those of other communities in this study. McGrath is one of two examined communities in which private interests own tanks. In other villages, all tank owners are essentially public entities. Although interests of public owners may differ, these interests could be expected to be more aligned than those of private corporations. In addition, McGrath is the only community in the study that is not predominantly Native in population. Unfortunately, this diversity may be an obstacle to development of a consolidated tank farm.

Tank farm consolidation faces similar obstacles in many communities. Tank farm owners see several risks in consolidation:

- Tank owners believe consolidation puts their fuel supply at risk. Typically, fuel from a consolidated farm is piped to the location of use. Having to transport fuel through lines from a remote source is thought to increase the risk of fuel being unavailable due to freezing or other problems with lines. While maintaining proper grades of fuels and mixtures can remove this risk, fuels with lower pour points are more costly.
- Tank owners fear increased exposure to liability. Even if tank owners have no reason to fear that other tank owners in a consolidated farm will not maintain their tanks, they would rather not expose themselves to the risk of failure of tanks of another owner or of commonly used equipment such as feed piping. This risk can be reduced (but probably cannot be eliminated) with explicit contractual obligations for maintenance of the tank farm. Alternatively, insurance requirements could alleviate these concerns. To help overcome this risk and to provide general coverage for spills, AEA is working toward developing an insurance pool for tank farm owners in Alaska. AEA believes that substantial reductions in premiums may be realized if several tank owners (and tank farm owners) contract jointly for facility insurance (Marchegiani, 2000).
- Many tank owners are more comfortable having their fuel supplies located on or adjacent to their own property, near the point of use and under their own exclusive supervision and control. They are concerned that tank farm consolidation at a comparatively remote site will compromise the security of their fuel supplies from theft and the security of their tanks from damage or misuse.

9.4 Analysis of Strategies

Two aspects of bulk fuel storage are considered in this section:

- The actual contributions of different types of tank owners to the financing of tank farm development
- The likely effects on fuel prices of requiring local participation in tank farm financing

9.4.1 Local Contributions to Tank Farm Development

Overview. This section examines the degree of local participation in the financing of bulk fuel storage facilities. Based on the seven villages examined, it appears that bulk fuel storage facility owners rely heavily on state and federal grants to fund development of their fuel storage. Development of strategies to obtain local contributions to development of bulk fuel storage is therefore suggested for further study in later stages of the project or other studies.

Analysis. A full listing of the tank owners in each village appears in Table 9-17. For each village, Table 9-17 includes percentage of total development cost of each entity by type and the percentage of total tankage in the upgraded tank farm owned by the entity. In the table, all grant money is attributed to the source rather than the party that acquired the grant. Grants such as CDBGs are therefore shown as federal government contributions since the federal government is the grantor.

Table 9-17. Village Tank Farm Development Financing: Percent of Total Financing by Contributor and Percent of Total Storage Capacity by Tank Owner

Village	Percent by Contributor / Tank Owner						
	Federal [a]	State	Schools	Municipal	Native Village	Native Corp.	Private
McGrath							
Percent of Total Financing	0	85.4	0	0	0	0	14.6
Percent of Total Capacity	0	0	0	0	0	0	100.0
Atmautluak							
Percent of Total Financing	35.3	62.6	2.0	0	0 [a]	0	0
Percent of Total Capacity	0	0	36.4	0	26.8	36.8	0
Arctic Village							
Percent of Total Financing	79.6	20.4	0.0	0	0.0*	0	0
Percent of Total Capacity	0	0	70.4	0	29.6	0	0
Buckland							
Percent of Total Financing	100.0	0	0.0	0.0 [a]	0.0	0	0
Percent of Total Capacity			21.6	26.1	52.3	0	0
Emmonak							
Percent of Total Financing	75.9	14.5	0	0.0	0	9.6 [a]	0
Percent of Total Capacity	0	0	0	14.3	0	85.7	0
Noorvik							
Percent of Total Financing	71.7	26.4	0.0	0.0	0.0 [a]	0	1.9
Percent of Total Capacity	0	0	24.9	12.2	41.6	0	21.3
Selawik							
Percent of Total Financing	66.0	34.0	0	0	0.0 [a]	0	0
Percent of Total Capacity	0	0	0	0	100.0	0	0
Percent of Total Spending	**71.6**	**25.1**	**0.3**	**0.0**	**0.0**	**2.2**	**0.8**

Source: AEA, 2000.
Note: All federal grants are considered federal contributions for purposes of this table.
[a] The tank farm is on land owned by the entity identified in the column heading.

Only one tank farm received any funding through state or federal loans. Emmonak Native Corporation received a $215,000 Power Project Fund loan from AIDEA for the tank farm upgrade currently underway in that village. All other state and federal governmental money was grant money.

Local sources of financial contributions to tank farm upgrades in the villages considered are as follows:

- McGrath Power &Light, which contributed $30,000 or14.6 percent of the cost of the upgrade of its tank farm in McGrath

- The Emmonak Native Corporation, which through a Power Project Fund loan from AIDEA contributed $215,000, or 9.6 percent of the total cost of the upgrade and consolidation of the bulk fuel storage facility in Emmonak
- Morris Trading Company, which contributed $50,000 or 1.9 percent of the total cost of the tank farm consolidation in Noorvik

Notably, more than 95 percent of tank farm costs in the villages analyzed are borne by federal and state governments. The federal government contributed two-thirds or more of the cost of upgrades in five of the seven communities, and two-thirds of the total cost of all tank farm development in the seven villages. State government entities contributed an additional 25 percent of the development costs of the tank farms and more than 60 percent of the costs to the two farms that the federal government did not fund.

The two wholly private entities involved in the upgrades contributed to the development. McGrath Power & Light contributed approximately 15 percent to the tank farm upgrade for which it was sole owner. Morris Trading Post in Noorvik contributed about 2 percent to the tank farm in which it owns tanks. This contribution should not be viewed as insignificant since the company owns only about 20 percent of the capacity in the consolidated farm. Assuming that the cost of tank capacity can be distributed equally among the owners, the contribution of Morris Trading Post is approximately 10 percent of the cost of its capacity.[48]

Other types of local entities rarely participated in the funding of tank farm upgrades. Municipal governments and Native villages made no financial contributions to any of the tank farms in which they own tanks. The City of Buckland, however, did provide the land for the development of its tank farm. One school district and one Native corporation contributed to the cost of tank farm upgrades. These entities contributed approximately 5.5 and 11.2 percent of the prorated cost of their storage capacities, respectively. Based on the examples considered, state and federal funds account for the almost all of tank farm upgrade costs. Local contributions have been particularly rare, especially when considering that rural schools are funded by the state government.

Conclusions. In seven villages analyzed as case studies, local entities contributed only a small fraction of the total spending required for bulk fuel storage facilities and in many cases did not participate at all. Federal and state sources accounted for approximately 97 percent of the total spending for bulk fuel storage facilities in the seven villages.

9.4.2 Fuel Cost Impact of Private Investment

Overview. This subsection estimates additional fuel costs that would result from requiring tank owners to pay a portion of the cost of development of their tank farms. In addition, in the two cases in which fuel suppliers participated in the funding of their bulk fuel storage facilities, the additional fuel costs attributable to the cost of funding bulk fuel storage are estimated. The estimations assume that tank owners debt-finance their contribution and that the tank owner passes on the full cost of these debt payments to fuel purchasers through an increase in fuel prices.

The analysis suggests that if the full cost of bulk fuel storage is passed on to purchasers, additional fuel costs will be between 6 and 28 cents per gallon, depending on financing terms. This disparity suggests that further study of financing options should be undertaken.

[48] This assumption may not be true since some tank owners may contribute previously owned tanks and other equipment to the tank farm. In addition, land contributions should not be viewed as insignificant, since some risk of liability arises with the development of a tank farm on the property.

Analysis. In the case of the Emmonak Native Corporation, which debt-financed its funding contribution, the additional cost of fuel to consumers can be estimated based on their actual debt payments under the loan. Since the AEA standard is to build tank farms to hold fuel volumes approximately equal to fuel requirements for 1 year for the tank farm owner, the total fuel sales from the corporation's tanks may be assumed to equal its total capacity, 360,000 gallons. The total annual payment of the corporation for the tank farm loan is $17,711.52, which is made in two equal, semiannual payments. If the corporation passes this cost, in its entirety, on to fuel users the additional cost of fuel would be $0.049 per gallon.

Similarly, the Morris Trading Company contributed $50,000 to the development of the consolidated tank farm in Noorvik. The company has 78,100 gallons of capacity in the tank farm. If the company financed its contribution with a 20-year loan at an interest rate of 10 percent, its annual payment would be $5,872.98. If this cost were passed on to fuel purchasers, the price of fuel would rise by $0.07 per gallon.

The second part of this analysis examines the change in the cost of fuel for all tank owners that participated in tank farm upgrades and make retail sales of fuel, as if they to had participated in the funding of the tank farm upgrade. Table 9-18 shows the results of that part of the analysis, including the cost of capacity for each tank farm upgrade and the added cost of fuel, assuming that the full cost of the tank owner's contribution is passed on to retail fuel purchasers in fuel prices.

The analysis is applied to each tank owner that makes retail fuel sales.[49] Results are reported for payment of 10 and 20 percent of the prorated costs of tank capacity, assuming that the cost of tank capacity is equally distributed among the owners in each tank farm. For example, a retailer that owns 20 percent of the capacity in a tank farm that cost $1 million would be assumed to have a $200,000 interest in the tank farm upgrade. If required to contribute 10 percent of the cost of its share in the upgrade through debt financing, the tank owner would be assumed to debt-finance $20,000. Tank owners are assumed to finance their debt on the private market at an interest rate of 10 percent per annum. As in the case of the Emmonak Native Corporation's Power Project Funding loan, rates might be lower if funds are available from a government lender. Results are reported for loan terms of 10 and 20 years. Since AEA often sizes tank farm capacity by annual usage, each retailer's annual sales are assumed to equal its storage capacity.

The results suggest that fuel costs will increase by 8 to 14 cents per gallon if a retailer takes out a 10-year loan for 10 percent of its share of the capacity costs, at an interest rate of 10 percent per annum. A contribution of 20 percent of a retailer's share has a substantially greater effect, with fuel costs rising between 22 and 42 cents per gallon. Extending the loan period to 20 years mitigates this effect substantially. If a 20-year loan is used to finance a 20 percent contribution to the cost of a retailer's capacity, the analysis suggests that fuel prices will increase between 10 and 18 cents per gallon. Reducing the contribution of the retailer to 10 percent of its capacity costs would reduce the cost increase to a modest 6 to 10 cents per gallon.

Conclusions. The results of the analysis suggest that if a 10 to 20 percent share of the cost of bulk fuel storage is passed on to fuel purchasers, the additional fuel costs will between 6 cents and 42 cents per gallon depending on the terms of financing.

[49] Since the McGrath tank farm involved only the local utility, McGrath Power & Light, McGrath is omitted from this analysis. Arctic Village is also omitted from this portion of the analysis, because expenditures at Arctic Village also include a power plant. Arctic Village will be included in another phase of this project if costs can be accurately apportioned between the power plant and the tank farm.

9.5 Conclusions and Recommendations

In recent years, AEA has made significant efforts to consolidate bulk fuel storage facilities in rural communities in Alaska. Based on the cases considered in this analysis, AEA has achieved significant success through these efforts. In one of the seven communities considered in this study, Atmautluak, the AEA supervised tank farm upgrade succeeded in consolidating all of the community's bulk fuel storage into a single facility. In four others, a portion of the bulk fuel storage facilities in the community was consolidated by the upgrade.

Bulk fuel storage facilities in rural Alaska are financed almost exclusively by the state and federal governments. In only three of seven tank farm upgrades considered by this report were there any local contributions to the costs of the upgrade. In no case did local funding exceed 15 percent of the total cost of the upgrade. The contribution exceeded 10 percent in only one case. This occurred in the upgrade of a tank farm in McGrath owned solely by McGrath Power & Light.

The impact on fuel prices from requiring tank farm owners to pay for a portion of the construction costs could be significant. The preliminary analysis conducted in this study suggests that fuel costs will increase by 8 to 14 cents per gallon if a retailer takes out a 10-year loan for 10 percent of its share of the capacity costs, at an interest rate of 10 percent per annum. A contribution of 20 percent of a retailer's share would have a substantially greater effect, with fuel costs rising between 13 and 18 cents per gallon. Extending the loan period to 20 years would mitigate this effect substantially. If a 20-year loan were used to finance a 20 percent contribution to the cost of a retailer's capacity, the analysis suggests that fuel prices would increase between 11 and 21 cents per gallon.

These impacts are such that tank farm financing issues should be studied in more detail in the next stage of the Rural Energy Plan. Additional research could include the consideration of more villages and a more comprehensive analysis of the effects on fuel prices.

Table 9-18. Capacity Costs and Increased Fuel Costs Resulting from Retail Owner Contributions to Tank Farm Construction Costs

		Cost ($)		Costs with Varying Loan Terms ($)							
				10-Year Loan for 10 Percent of Cost		10-Year Loan for 20 Percent of Cost		20-Year Loan for 10 Percent of Cost		20-Year Loan for 20 Percent of Cost	
Tank Owner	Fuel Capacity (Gallons)	Prorated Capacity	Per Gallon of Capacity	Annual Loan Payment	Per Gallon of Fuel	Annual Loan Payment	Per Gallon of Fuel	Annual Loan Payment	Per Gallon of Fuel	Annual Loan Payment	Per Gallon of Fuel
Atmautluak Limited	66,000	576,971	8.74	9,390	0.14	18,779	0.28	6,777	0.10	13,554	0.21
Native Village of Buckland	151,800	1,151,586	7.59	18,742	0.12	37,483	0.25	13,526	0.09	27,053	0.18
Noorvik Native Corporation	152,400	1,101,937	7.23	17,934	0.12	35,867	0.24	12,943	0.08	25,887	0.17
Morris Trading Company	78,100	564,707	7.23	9,190	0.12	18,381	0.24	11,597	0.08	13,266	0.17
Emmonak Corporation	360,000	2,091,429	5.81	34,037	0.09	68,074	0.19	24,566	0.07	49,132	0.14
City of Emmonak	60,000	348,571	5.81	5,673	0.09	11,345	0.19	4,094	0.07	8,189	0.14
Native Village of Selawik	250,000	1,175,255	4.70	19,127	0.08	38,253	0.15	13,805	0.06	27,609	0.11

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Appendix A— Study Team Responses to Comments

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
A. Don Eller, Tanana Power Company, Inc. (comment letter included)	
1. Concerned about lack of discussion of utility operations, maintenance, and management	1. The Institute for Social and Economic Research (ISER) is preparing a companion report, *Rural Utility Operations, Maintenance, and Management Study*.
2. Recommends collecting data on community electrical usage to be able to accurately measure the success of any new strategy or technology	2. Could be included in next phase of analysis
3. Suggested that using No. 2 diesel fuel year-round would lower costs	3. Paragraph added to Subsection 7.3.2, Waste Heat Recovery Systems, to address the possibility of using waste heat to keep storage tanks and distribution lines warm enough to permit the use of No. 2 diesel fuel year-round. Sentence also added to Subsection 3.3.4, Replacing Diesel No. 1 by Using Additives or Blending Fuels, to describe this technique.
B. Loren Gerhard, Southeast Conference (participated in December 15, 2000, conference call)	
1. Expressed concern that interties were not recommended for further consideration and requested that section on interties be more location-specific so that viable opportunities in Southeast Alaska are not overlooked (Subsection 5.3.6)	1. Conclusion to Subsection 5.3.6, Interties, modified. Final recommendation in report is unchanged, but language explicitly notes that certain projects may be viable.
C. Nicholas Goodman, Northern Renewables, LLC (comment letter included)	
1. Clarified that Tidal Energy of Alaska, Inc. is actually Tidal Electric of Alaska, Inc. (Subsection 5.3.11)	1. Correction made
2. Noted that TDX Corporation developed the St. Paul wind energy facility entirely with private funds (Subsection 5.23.12)	2. No changes necessary in report
3. Requested that wave power be considered in the analysis—perhaps in Subsection 5.3.13, Other Strategies	3. Comments on wave power added to Subsection 5.3.13
D. Bob Grim, Alaska Power and Telephone Company (participated in December 15, 2000, conference call, and submitted written comments—letter included)	
1. Expressed concern that interties were not recommended for further consideration and requested that section on interties be more location-specific so that viable opportunities in Southeast Alaska are not overlooked (Subsection 5.3.6)	1. Conclusion to Subsection 5.3.6, Interties, modified. Final recommendation in report is unchanged, but language explicitly notes that certain projects may be viable.

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
2. Expressed concern that the estimated fuel savings with automated switchgear might be too high (Subsection 2.3.1, Page 2-9)	2. Paragraph in Subsection 2.3.1, Generating Equipment and Related System Controls, (Page 2-9) edited to address comments and incorporate new information.
3. Recommended creation of a menu of best practices	3. Could possibly be included in ISER report, *Rural Utility Operations, Maintenance, and Management Study*
E. Meera Kohler, Alaska Village Electric Cooperative, Inc. (participated in December 15, 2000, conference call, and submitted written comments—letter included)	
1. Requested clarification in report such that discussion of switchgear automation and real time economic dispatch (Subsections 2.3.1.1 and 2.3.1.2) do not overlap or are more clear	1. In many cases, utilities install RTED capabilities at the same time as automated switchgear. In this report, these strategies are viewed as independent but linked opportunities. (Footnote added to discussion of improved switchgear in Subsection 2.3.1.)
2. Expressed concern that the real cost of installing automated switchgear is higher than estimated in the report	2. Text added to note that costs could be higher. Cost estimates could be refined in next phase of research.
3. Noted that real-time economic dispatch systems tend to increase the load factor on generating sets and can reduce the time to overhaul	3. Text added to note that present value of shorter interval between overhauls has not been calculated. This additional cost could be considered in the next phase of research.
4. Recommended use of recovered heat to raise the temperature of stored fuel to permit the use of No. 2 diesel year-round (to take advantage of higher Btu value and lower cost relative to No. 1 fuel)	4. Paragraph added to Subsection 7.3.2, Waste Heat Recovery Systems, to address the possibility of using waste heat to keep storage tanks and distribution lines warm enough to permit the use of No. 2 diesel fuel year-round. Sentence also added to Subsection 3.3.4, Replacing Diesel No. 1 by Using Additives or Blending Fuels, to describe this approach.
5. Noted communities where interties could be viable in conjunction with wind generators	5. Conclusion to Subsection 5.3.6, Interties, modified. Final recommendation is unchanged, but language explicitly notes that certain projects may be viable and utilities or developers in certain regions may be expected to promote the use of interties in certain regions of the state.
6. Introduced the idea of having the state or other entity coordinating bulk fuel bidding and purchasing for rural villages, and managing a fund to even out fuel price fluctuations	6. The possibility of coordinated fuel purchases at the state level, a revolving fund, or possible state loan program to ensure stable fuel prices could be explored as a separate research topic. The evaluation of this idea should include an analysis of the source of funds, as well as the legal and political dimensions of the strategy. (Villages that have the money to invest in a fund now to offset future price spikes could do so freely. However, no attempt is made here to contemplate having the state play an active role in mitigating price fluctuations. Such a strategy would resemble investing in the futures market and goes beyond the scope of this report.)

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
7. Recommended an evaluation of current design and construction practices with the perspective of standardized or modular designs for generating systems, tank farms, and distribution systems	7. Different methods of contracting and construction management have been recommended for field testing and possible implementation. As better practices are identified, more attention could be given to standardized design and construction standards. With regard to generating and distribution systems, the second phase of the Rural Energy Plan—with additional information from the ISER report—could explore the potential benefits of standards practices (for construction and/or operations).
F. Brad Reeve, Kotzebue Electric Association (comment letter included)	
1. Expressed concern that the study "asked the wrong question" by focusing on the economic viability of strategies or technologies rather than trying to identify the best application	1. A primary objective was to determine which technologies or strategies offer the most promise over the next several years to reduce the cost of electricity in rural Alaska. Strategies or technologies that do not offer potential for significant savings for more than 5 communities could still be identified by individual utilities or communities as having valuable uses and applications.
2. Concerned about lack of discussion on management, engineering, maintenance, and operations	2. ISER is preparing a companion report, *Rural Utility Operations, Maintenance, and Management Study.* Therefore, those issues are not addressed in this report.
3. Requested additional work to incorporate an evaluation of community dynamics; provided example of how a technology that might not have been viable when analyzed in isolation, was viable in conjunction with a specific economic development project	3. Certain technologies or strategies could be considered to be more attractive when benefits include increased employment opportunities or other forms of economic development. Such specific instances would need to be analyzed on a case-by-case basis. Trying to anticipate such opportunities and to properly model the related community dynamics is beyond the scope of this analysis.
4. Expressed concern that Kotzebue Electric Association was not contacted for current data on wind energy systems (felt that Subsection 5.3.12, Wind Energy, minimizes the efforts of the Kotzebue Electric Association)	4. Subsection 5.3.12 was based on a report prepared for AIDEA by ISER. Additional information was not collected (and Kotzebue Electric Association was not contacted) because the ISER report was sufficient to reach a decision to recommend wind energy for additional research. The most current information should be used and input from Kotzebue Electric Association requested in the next phase of the project.
G. Art Ronimus, Consultant for Alaska Native Tribal Health Consortium (participated in December 15, 2000, conference call, and submitted written comments—letter included)	
1. The study should add the potential heat recovery from utilizing diesel engine exhaust (considering the source of heat, the figures shown in Table 7-8 of the report were not accurate).	1. Paragraph added to Subsection 7.3.2, Waste Heat Recovery Systems, to expand the description of benefits from waste heat recovery systems

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
2. Believes that 100,000 Btu of available waste heat is equivalent to 1 gallon of fuel oil displaced; felt that report underestimated this conversion factor in Subsection 7.3.2, Waste Heat Recovery Systems	2. No changes made. Edits made in response to Mr. Ronimus's first and third comments show a greater possible value for recoverable heat collection systems and the strategy is recommended for additional study. Further research in the next phase could include more precise estimates of the Btus available in recoverable heat.
3. Suggested that heat loss between heat source and end user is typically less than 15 percent—recommends a figure of 5 percent	3. Sentence added to Subsection 7.3.2, Waste Heat Recovery Systems, to acknowledge that heat loss from recoverable heat collection system to location of end use could be less than 15 percent. Table in Subsection 7.3.2 also modified to show wider range of efficiency loss.
4. Requests additional study to determine utilization of waste heat recovery systems in rural Alaska	4. Additional study could be undertaken in next phase of project. (In the current report, this strategy is recommended for further study at the next phase of the Rural Energy Plan.)
5. Requests that a higher (more accurate) figure be used for the price of fuel—a figure of $1.00 per gallon is used in the report.	5. A review of data from the Power Cost Equalization (PCE) database near the beginning of the project indicated that $1.00 per gallon was a typical fuel price for PCE communities. This price was selected for all subsequent analyses.
H. Dan Salmon, Igiugig Electric Company (participated in December 15, 2000, conference call)	
1. Commented on wide range in operations and maintenance (O&M) efforts in rural communities and suggested that O&M standards be set	1. ISER is preparing a companion report, *Rural Utility Operations, Maintenance, and Management Study.*
I. Jim Strandberg, Regulatory Commission of Alaska (participated in December 15, 2000, conference call)	
1. Expressed concern with the use of Power Cost Equalization program data on line loss (stated that data are inconsistent and the definition of "net generation" varies)	1. No other data available for study. Next phase of plan could include site analyses and case studies to determine the actual line loss in rural Alaska (or to permit quality control of PCE data).
J. Nan Thompson, Regulatory Commission of Alaska (comment letter included)	
1. Expressed concern with the limited analysis in Subsection 2.3.2, Distribution System Improvements. Added reliance on Power Cost Equalization program data on line loss may not be a good foundation and more work should be done before this strategy is dismissed.	1. Three technologies were identified that could reduce distribution system losses in rural systems, and two technologies or strategies were identified to improve distribution efficiency. None of these technologies appears to offer enough savings to justify an aggressive implementation program at the state level. Additional data and research are needed to determine the cause of high line loss in rural Alaska. However, such research could be conducted as part of the Circuit Rider or other program.

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
2. Expressed concern with the general approach of looking at rural power systems as a single category; recommended that, at a minimum, rural power systems could be divided into "small" and "large" systems	2. This distinction could be made during the next phase of the project if more detailed analyses suggest that different strategies might be viable for one size rural utility but not another.
K. Scott Waterman, Alaska Housing Finance Corporation (participated in December 15, 2000, conference call)	
1. Requested that more attention be given to the connection between energy consumption and water and sewer projects	1. Demand projections, including the demand for energy from new water and sewer systems, should be included in the next phase of the project.
L. Robert Wilkinson, Copper Valley Electric Association, Inc. (comment letter included)	
1. Would like a clear definition of rural Alaska	1. Definition added to introduction. (For the purposes of this report, rural Alaska includes all of Alaska except for the interconnected region of the Railbelt, communities in the Four Dam Pool, Juneau, and Sitka. All communities eligible for the state's Power Cost Equalization program are included in this definition.)
2. Requested that analyses include the cost of upgrades in equipment that will be necessary due to obsolescence, and the cost of training utility personnel	2. Life cycle costs and replacement costs are considered with different strategies throughout the report. The cost of training utility personnel is likely to be included in the companion report, *Rural Utility Operations, Maintenance, and Management Study,* currently being prepared by ISER.
3. Suggested that discussion on operations, maintenance, and management was limited	3. ISER is preparing a companion report, *Rural Utility Operations, Maintenance, and Management Study.*
M. Marvin Yoder, City of Galena (participated in December 15, 2000, conference call and submitted written comments—letter included)	
1. Noted sources of coal in central Alaska and provided information on solar energy based on experiences in Galena.	1. No change necessary in report.
2. Requested analysis of either barging compressed natural gas down the Yukon River or using a pipeline to serve the same area	2. It is not within the scope of this report to predict what route a natural gas pipeline might follow from the North Slope and whether a spur to different parts of rural Alaska would be feasible. In addition, due to the lack of infrastructure and limited availability of natural gas near the Yukon River, no attempt has been made to explore the potential costs or benefits of barging natural gas to rural Alaska. (WAVE and Calista have discussed the idea of barging natural gas, but the only data that are available at present are for the cost of shipping small canisters of natural gas for domestic use.)

Responses to Comments to Rural Energy Plan Screening Report (October 2000 Draft)

Comment	Response
N. Eric P. Yould, Alaska Rural Electric Cooperative Association (participated in December 15, 2000, conference call and submitted written comments—letter included)	
1. Requested that economic assumptions and criteria be stated together clearly toward the front of the report	1. New table added at beginning of section on diesel efficiencies and existing tables expanded to show relevant information (discount rate, fuel escalation rate, heat rate of machines, etc.)
2. Stressed that the screening report is but one element in an energy plan; noted the importance of other efforts, such as the ISER report on operations, maintenance, and management	2. No changes necessary

Tanana Power Company, Inc.

P.O. BOX 873509 WASILLA, ALASKA 99687 TELEPHONE 907-373-5599 OR (907) 366-7101

December 11, 2000

To: Dick E.

cc. David/Dick

Robert Poe, Jr.
Executive Director
480 West Tutor
Anchorage, Alaska 99503

Subject: Rural Energy Plan - Review of Draft Screen Analysis

Dear Mr. Poe:

After reviewing the Alaska Rural Energy Plan, I would agree with many of the recommendations put forth with regard to lowering the cost of energy produced in rural Alaska. One important item which did not appear in the report was emphasis on utility management. As I stated before in the Power Cost Equalization White Paper, utility management is a major consideration with regard to long term costs. If utilities are not held accountable for the generous contributions from the state, the fundamental entity which has the greatest control of long term costs remains unaccountable, breeding dependence on the state rather than driving energy costs. All state contributions should be tied to some fundamental level of accountability which if not met allows the state to restructure management.

Tanana Power Co. Inc. has implemented an automated control system in its generation facilities and has seen it's efficiency go from about 11.5 kWh/gal to inexcess of 13 kWh/gal. While the 1.5 kWh/gal does not seem like a lot, it amounts to over a 13% increase in efficiency and can definitely be seen when comparing annual fuel usages. While the use of automated control has tremendous benefits without the local understanding of how to operate and maintain it, automation could actually make the system less reliable. Before trying to implement any automated control system, the use of recorders to obtain accurate information about the communities electrical usage is the fundamental place to start. These devices are relatively inexpensive. Making sure that the recorder was working and that the information was sent in on a regular basis could be the start of an accountability program. Along with the fuel usage this information would tell AIDEA much of the information with regard to the utility. The information gained would help size generators for a community, which would lead to better efficiency, as well as allow AIDEA to discern which communities would benefit the most from an automated control system. The recorder could also be tied into a door switch or even push buttons to allow other fundamental information to be collected.

Another simple way to help lower costs would be to burn #2 fuel year round, #2+10 in the summer and #2-15 in the winter. In Tanana, which has fairly extreme winter temperatures, #2-15 is burned all winter. We are able to use #2 fuel all winter as our long term storage tanks are stored reasonably close to the day tanks and have a large diameter pipe (3"-4") feeding the day tanks. It also helps that we cover the pipe with snow for extra insulation.

The Alaska Rural Energy Plan is correct in its cost reduction strategies. However, it has failed to include the item which could have the greatest impact on long term costs, utility management accountability.

Tanana Power Co., Inc. would like to thank you for the opportunity to comment on your draft plan and hopes that the AIDEA finds our suggestions helpful. We would be pleased give you a tour and demonstrate the use of our automated controller and would welcome any suggestions you might have on how to improve our operation.

Sincerely,

Don Eller
Vice-President

Enclosure

STATE OF ALASKA

THE ALASKA PUBLIC UTILITIES COMMISSION

Before Commissioners:

Sam Cotten, Chairman
Alyce A. Hanley
Dwight D. Ornquist
Tim Cook
James M. Posey

In the Matter of the Consideration of Standards To)
Address a Coordinated Energy Resource Conservation)
and Efficiency Program for Regulated Electric Public) R-96-1
Utilities)
)

RECOMMENDATIONS AND COMMENTS
REGARDING STAFF REPORT R-96-1

Tanana Power Co. Inc. (TPC) would like to go on record stating that TPC's 1996 Annual Report was submitted April 30, 1997 at 2:58 p.m... Footnote 2 in the STAFF REPORT is incorrect. Attached is a copy of the cover page of the 1996 Annual Report stamped by the APUC (Attachment 1).

It is very important to note that any comparison between small rural utilities solely dependent on diesel using one large engine at any given time for production, and a large electrical utility that is interconnected with other producers should be viewed with skeptism. It should also be noted that the data used is only representative of regulated electrical utilities, not total electrical utilities in Alaska. There are over 60 other certified electrical utilities not represented because these utilities are not regulated. TPC believes that all comparisons should be done using similar structured certified electrical utilities. The needs and structure of both the communities and electrical utilities in rural Alaska are very different from those of urban Alaska and comparisons using data of the two will lead to flawed conclusions. The position and recommendations in these comments are taken from a rural perspective.

Recommendations for COPA Revisions

COPA is not an incentive or a discentive for electric utilities to become more efficient. COPA is, as stated in the staff report, a method for recovering increased fuel costs without forcing utility customers to bear the substantial expense of a rate case. If it is the intention of the commission to create incentives for electric companies using internal combustion engines for electrical energy production, increase the deprecation rate for prime movers. This concept is very similar to what occurred in the local exchange carrier (LEC) industry when digital switches became available. In order for LECs to keep current with technology, depreciation rates went from 3.33% to 10.0% on central office switching equipment. The current depreciation rate of 6.66% (15 years) for prime movers is hardly an incentive to keep current with advances in technology.

The cost of a prime mover is relatively insignificant when compared to the cost of the fuel which the engine will burn over it's life. For example, in 1995 a Cat 3508 diesel engine rated at 450kw @ 1200 rpm costs $112,534.00. In one year, the amount of fuel which the engine will burn, loaded at 225kw, is 153,300 gallons with a 12.86 kwh/gal efficiency. At $1.25 a gallon this would equate to $191,625.00 in annual fuel costs. If engine technology changed to increase the efficiency to 13.36 kwh/gal at 225kw (a 3.9% increase in efficiency), the fuel savings would be about 5740 gallons annually. If the engine is used as described above the expected engine's life is 22,000 hours, approximately 2.5 years of continuous run time, before a major overhaul would be required. Assuming a utility has 3 engines for redundancy which are run in an even rotation, it would take 7.5 years from start up until an overhaul is required. The cost of a major overhaul is approximately $65,000.00. The resale value of the engine described above with 22,000 hours is approximately $20,000.00. When the engine reaches 22,000 hours it would be prudent to sell the engine (+$20,000.00) and purchase a more fuel efficient engine (-$112,534.00), and take benefit of the fuel saving over the new efficient engines life (+$53800.00= 7.5 years X 5740 gallons / year savings X $1.25/gallons) (cost of overhaul $65,000.00 verses

$38,734.00=$112,534-($20,000+$53,800)). This example is very idealized. However, it does point out that the current depreciation rate of 15 years for internal combustion engines is much longer than it should be. The reason for new technology not being implemented is not COPA, it is the current 15 year depreciating rate on prime movers.

It should also be noted that one of the greatest disincentives of increasing generation efficiency in rural power production is the Power Cost Equalization program (PCE). The State of Alaska pays for 95% (actual percent of costs paid depends on the funding level of the program) of all eligible costs per kwh between 9.5 cents/kwh and 52.2 cents/kwh. Utilities have no real incentives to improve efficiencies given that a large portion of operational costs are recovered from a third party. Attached is a white paper regarding PCE (Attachment 2).

Rural power consumers have a built in control on their demand. The control is the high cost paid for electricity. The characteristics of rural demand for electricity are very different than urban demand. Many rural residential customers rarely exceed monthly minimums. The rural residential customers demand for electricity is for "essentials", heat when its cold, light when its dark, and cooling when its warm. Rural electrical needs are for the basics, not for luxury items like dish washers, electric ovens, electric hot water heaters, etc. Peak loads are determined by a few major users who's use pattern is relatively inflexible. It is not reasonable to request a school, a city office, the Laundromat, or other offices in town to operate in off peak hours interfering with their ability to conduct business efficiently. Once it has been determined what the peak load is, an internal combustion engine sized to handle the peak load is much more fuel efficient. When dropping below 80% of peak load internal combustion engines have a rapid decline in fuel efficiency. There are however large season swings in peak usage. Large savings can occur through load matching, running the proper sized generator for the load. For rural Alaska, supply side management of electricity makes much greater sense than demand side management. One of the primary items needed to make informed decisions regarding supply side management of electricity is load characteristics which are easily obtained through a recording device.

T & D Efficiency Levels

To compare efficiency levels for T & D and other losses as done on Staff Report attachment PcM-1 is an inaccurate comparison. To accurately compare T & D and other losses, it must be done on a basis which actually takes into consideration equivalent utility operating characteristics. Take for example utility A has 40 miles of transmission line, runs large pumps to recover and distribute heat to community faculties (not accounted for in kwh sold), and uses electric radiator fans (not accounted for in kwh sold) to help with engine cooling, verses utility B which has 4 miles of transmission line and dissipates heat through a radiator fan driven directly off the engine. As can be seen by the example, Utility A could be much more efficient than utility B from an operational stand point, having less line loss per mile and recovering more BTUs per gallon than utility B. Yet, when compared to the method used on Staff Report attachment PcM-1, Utility B would be more efficient than utility A.

The establishment of reasonable bounds for equivalent utility operating characteristics would be helpful for regulated utilities as well as all PCE participants. However, this type of analysis takes a large amount of time and operational knowledge of all the utilities in the state, possibly making this task so large and complex the APUC would find the its resources would be better spent elsewhere.

Statewide Energy Conservation Program

Grouping and applying a program based arbitrarily on utility characteristics such as regulated and unregulated status is a recipe for disaster. The Federal government has recognized this in the rewriting of the Telecommunications act, creating different rules for rural and urban areas. The needs and characteristics of TPC and its consumers are much more comparable to an unregulated utility of similar size operating in rural Alaska than they will ever be to a large utility such as Chugach and its customers. Therefore it would make sense to exclude smaller rural electric utilities from DSM allowing them to focus on more relevant rural issues.

Overview

There are distinct differences between urban and rural utilities and any generic rule should take into account these differences. Individual electrical utility operations are very different and any standards or comparisons should be based on equivalent utility operating characteristics, rather than broad general characteristics. To properly and effectively address the needed changes for rural electrical utilities the input for change should be done through the PCE program in which most rural electrical utilities are participants, not the APUC since the majority of rural electrical utilities are not regulated. The current APUC 15 year depreciation of internal combustion engines should be reviewed since a small change in fuel efficiency has a very dramatic impact on long term operating costs. There are problems with electrical utility efficiency in rural Alaska, but the problems need to addressed through state policy not the rule making process.

Attachment 2

TANANA POWER CO., INC.
P.O. BOX 873509
WASILLA, AK 99687
(907) 373-5599

DATE: January 19, 1998

TO: The Honorable Al Adams
The Honorable Drue Pearce
Mr. Randy Simmons, Executive Director
Mr. Sam Colten, Commissioner
Mr. Eric Yould, Executive Director
Mr. Dewey Sken, Board President
Mr. Robert Beans, Chairman
Ms. Nancy James
Mr. Joe Griffith, Board Chairman
Mr. Robert Martin, Jr., General Manger
Charlie Walls

FROM: Tanana Power Co., Inc.

PAGES: 4

Power Cost Equalization White Paper

This report is not an effort to justify the existence of the Power Cost Equalization Program (PCE) in any way or form. Whether PCE stays or goes is a policy decision. Information on the support for and the history of PCE can be found in the Business Cache Volume 7, Number 3, cover page, the Alaska Digest October-November 1997, page 11, and the Anchorage Daily News, Friday October 17, 1997, Page B-8. Once it is agreed that PCE is a state program which is beneficial and desirable for all Alaskan residents, the next question is how can the existing program be made more effective.

This is one person's opinion, who currently works for an electric utility, of what changes should be made to improve the existing PCE program. The goal of the PCE program should be to lower the cost paid for electricity by rural consumers. In its current form, PCE compensation is cost based. Therefore, utility costs, up to a State determined ceiling, drive the amount of an electrical bill paid by the State of Alaska for the customer. This is just bad protocol. The electric utility which has the control of costs has no real incentive to minimize costs, since the State of Alaska will pay 95% of the verifiable and reasonable costs between $0.095 and $0.525. To compound this situation an overwhelming majority of electrical utilities receiving PCE are unregulated, therefore the APUC only does a cursory annual review of operating expenses and rate base. To further complicate the situation the State of Alaska gives grants to utilities. Alot of the grant money is directed towards municipal owned electric utilities for resolving problems the utilities should have resolved internally. These are the same utilities that are not regulated by the APUC.

One method to change PCE from a cost to an incentive based program, would be to do a regression analysis on the fuel and non-fuel expenses in relationship to size, miles from the major distribution point, miles of plant, peak load, average load, access to a road system, production size, corporate size, and any other factor which would influence the cost of electricity. From the regression analysis a PCE rate could be calculated for each utility based on the utilities specific characteristics in relationship to the total electrical industry. If this method is followed there will and should be long debates over which factors should be included in the regression analysis. However, through this method an absolute standard of costs based on the utilities specific characteristics would be developed. This would give utilities falling outside the typical cost area incentive to improve their performance while at the same time rewarding companies who are performing well. At some predetermined interval of time the regression analysis should be performed again to keep the formula current with individual company and industry wide changes. Companies who fall outside the typical costs as determined by the regression analysis would start to feel pressure from their consumers to improve efficiency and/or management. Unlike administering PCE via a cost based method this incentive based method allows market forces to work.

The ultimate beneficiary of the PCE program is the rural customers, but the electric utilities are the net beneficiaries. The current method of distributing PCE funds is based on the companies costs which determines the rate of compensation from the PCE program. The State of Alaska has only minor standards for the electric utility to meet in the form of kwh produced per gallon of fuel consumed. At the risk of offending some of the rural electrical producers, it should be made known that the lack of professional management and practices in the electric utility business are causing part of the rural electrical cost problem. The majority of electrical utilities are not regulated. The only oversight is the local city council which may or may not be sufficient. If the true goal of the PCE program is to lower the cost paid for electricity by rural consumers, the program should include some controls on utility management. Utility management should include that all participants in the PCE program keep their accounting records according to the standard FERC account codes and be submitted electronically for review annually. The review should include a comparative analysis of operating and capital expenses (which should include grants even though a dollar figure may not be spent by the utilities) with similar utilities. Utilities that have expenses which fall outside of the normal expense bounds should be specifically worked with to lower their expenses. This would be a process similar to the annual state access filings for the telephone utilities. The review would also ensure that proper practices are being followed for capital purchases, like when a generator is being replaced the utility has funds to replace the generator. For utilities regulated by the APUC submitting the accounting would be little different from submitting the Form M report. For non-regulated utilities it would make the utilities receiving PCE much more accountable to the State of Alaska, a small price to pay for receiving PCE. Another valuable practice would be to have individuals knowledgeable in electrical utility operations review the day to day practices and facilities of the utilities participating in the PCE program. The reports produced from these visits would then provide suggestions for improvements for efficiency to the utilities receiving PCE and then monitor whether the suggestions were followed through with the financial reporting.

While the State grants and loans are not part of PCE , the funds impact rural power costs. Much of the grant money is directed towards municipal owned electrical utilities. The utility's corporate structure should have nothing to do with the ability to get a grant. Grant money should not be, but is being used to purchase generators and other items which are considered part of the cost of typical operations. This practice is unfair and breeds dependence on the State rather than fostering self sufficiency and good management practices. One of the criteria for grant selection is based on health and safety issues. In reality if the utility is creating an unsafe condition and is causing health and safety concerns, one needs to step back and consider whether or not the utility should be in business. By granting the money for typical operating expenses which should be paid for by the utility, the State of Alaska only breeds dependence on itself. There are many conditions where the State funds are needed, take for example the bulk tank environmental compliance. This is an extraordinary expense brought about by government regulation, and will not have to be dealt with again. Outside of extraordinary expenses as mentioned above State grants and loans should be used for projects which lower the cost of power production or improves efficiency. A project which lowers the cost of producing electricity will create less demand on PCE, not promote dependence on the state.

The goal of the PCE program is to lower the cost paid for electricity by rural consumers. The existing program is wonderful in that it is very simple and gets PCE funds directly to those customers with high electrical costs. The problem with the current PCE is that it rewards for costs with no accountability. Changing the PCE compensation formula to reflect industry cost is an attempt to create accountability of each utilities cost to that of similar utilities in Alaska. Having all utilities participating in PCE supply standardized financial information and have their facilities reviewed and critiqued makes the utilities accountable to the State of Alaska. Changing the criteria and goals of grant and loan programs will create an overall approach to rural energy between different state programs. Removing the state as a possible funding source for the typical cost of doing business will create greater accountability of the utility to its customers.

The State of Alaska has been generous with its funding of rural energy needs. The problem is that these programs do not have the accountability controls built into them to accomplish the goal of lowering the cost of electricity for rural residents. Instead of the programs leading to lower energy costs, over time State energy programs have lead many utilities to depend on the State of Alaska for operating and capital expenses. Rural Alaskan residents do need help with their electrical needs, however, along with that help should be the responsibility of making the most of the available resources. Any programs aimed at lowering rural energy costs must have built in controls and accountability.

As PCE has controls and accountability associated with it, the PCE program needs stable consistent funding. In the near future, Rural Alaska will be supplied with electricity by diesel generation. Therefore, an annuity must be in place so that funding is available. A possible mechanism for funding PCE is a large initial sum of money invested in conjunction with the permanent dividend fund. Revenues that were generated from the investment could be used for the annual PCE funding. Any type of annuity that was set up must have the initial principal protected, to prevent use. The amount of principal required for such an annuity would be about 200 million dollars. Revenue overages from the fund could be reinvested to cushion the years when there are revenue short falls. If less demands were put on the PCE program, as should happen if it is revised, the excess funds could be used to fund some of the existing utility improvement programs which would cause even less demand on the PCE program. At some point in time when the PCE program is no longer needed then the initial principal could be used as the legislator sees fit. The current method of funding is only for the short term and needs to be changed.

There is one last issue which needs to be dealt with that directly affects the PCE funding. Fuel costs in rural Alaska are artificially high. The artificially high fuel price is caused by a lack of competition or regulatory oversight in the bulk fuel supply business in rural Alaska. Essentially what is in place is an unregulated bulk fuel supplier monopoly. For example, a company purchasing 125,000 gallons of fuel a year flies fuel in 120 air miles because it is 10 cents a gallon cheaper flown in than purchasing from the barge bulk fuel supplier. PCE rates are artificially high because electrical producers are paying artificially high fuel costs. In the short term, regulation is necessary of the monopolistic bulk fuel business. In the long term, roads need to be constructed to connect communities to their supply centers. Rural roads would have a tremendous impact on the cost of living in rural Alaska.

The following is a recap of the suggestions for improving the PCE program:

1) Change the method of PCE compensation from a cost based system to an efficiency or standards based system.

2) In order to participate in the PCE program utilities must be accountable to the State of Alaska.

3) Tie available State funding for Rural Electric Utilities to the overall goal of driving down rural electric customer costs.

4) Set up a stable funding mechanism for PCE.

5) Take steps to lower the artificially high fuel costs in rural Alaska.

Rural Alaska's electric situation needs help. If we don't do something now, the customers in these rural communities as well as the State of Alaska will be paying the high price.

NORTHERN RENEWABLES, LLC
CONSULTING AND MANAGEMENT FOR RENEWABLE ENERGY TECHNOLOGIES

January 17, 2001

Mr. Dick Emerman
Alaska Energy Authority
813 West Northern Lights
Anchorage, AK 99503

Dear Dick:

Following up on our conversation last Friday, I wanted to submit some comments in response to the Screening Report for Alaska Rural Energy Plan. In general, I found the report to be both detailed and informative, and it is obvious a great deal of effort has gone into assembling this large document. With regard to the alternative energy section, I have the following comments:

1. Section 5.3.11- Tidal Energy: In the Analysis section, the report refers to "Tidal Energy of Alaska, Inc." The company is actually named Tidal Electric of Alaska, Inc. Later, in the Conclusions section, in referring to a 240W plant, (presumably 240 KW), the author indicates rather broadly that tidal power would not be competitive with diesel generation. Within this statement, it is not clear if this include fuel prices, fuel storage, O&M etc.

2. Section 5.3.12 – Wind Energy: In the Analysis section, it is worth noting that in addition to installing a wind power facility in St. Paul, TDX Corporation developed the project entirely with private funds, and has decreased generation costs as a result of the strong wind resource on the island.

3. Section 5.3.13 - Other Strategies (Not Analyzed): Another technology applicable in rural Alaska is wave power. During the latter half of 1999, Wavegen, a Scottish based company specializing in wave power development, conducted preliminary market studies and identified a number of prospective sites conducive to development. Most recently, in November of 2000, Wavegen commissioned a 500KW plant on a remote island off the north coast of Scotland. This plant now feeds electricity to the UK power grid at pool prices, and has a design life of 20+ years. Given the similarities between wind and wave resources, and the preliminary feasibility work conducted by Wavegen here in Alaska, I have no doubt the potential for near term deployment of the technology in rural Alaska is good.

Thank you for your time and consideration of my comments, and I look forward to reading the final version of the report upon completion.

Sincerely,

Nicholas Goodman

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Alaska Power & Telephone Company

Employee-owned and Community Minded.

MemoFax

To:	Richard Emerman-AIDEA	**From:**	Bob Grimm
Fax:	907-269-3044	**Pages:**	
Phone:	907-269-3000	**Date:**	1/2/01
Re:	Comments on Screening Study	**CC:**	Charlie Walls-Denali Commission Dave Germer-AIDEA

☐ **Urgent** X☐ **For Review** ☐ **Please Comment** ☐ **Please Reply** ☐ **Please Recycle**

● **Comments:**

Dear Dick:

Enclosed are some comments on the screening report prepared by Northern Economics.

The major concern we have about the report is the statement that electrical interties should not be recommended for further study. APC strongly disagrees with this statement ! I would encourage this statement to be rewritten!

Secondly, the report states that an improvement of 20% in fuel efficiency can be achieved by using automated switchgear. We believe this overstates the increase possible in fuel efficiency. We believe that once the generator units are upgraded to the newer model with flatter fuel curves the actual increase in fuel efficiency is around 4% by using automated switchgear. We would expect the

saving in operation and maintenance expenses by reducing on-site labor to exceed the value of the increase fuel efficiency.

Third, by creating a menu of best practices a systematic approach of employing these practices in each system can be developed and implemented.

Bob Grimm

Comments on screening study. 12-17-2000
By Bob Grimm

- Best practices need to be established and then used at all locations
- One size does not fit all.
- Continuous monitoring of new and emerging technology
- Command and control structure to insure regulatory compliance
- Automation to eliminate onsite labor

I would recommend that those utilities that are in compliance with the governing rules and regulations with a documented cost structure (generation, operation, and administrative) and satisfactory reliability be investigated to determine a menu of "Best Practices". I think much can be learned from the existing utility systems experiences and practices. We cannot just focus on just generation costs. The menu of best practices will need to also include maintenance, operation, administration, and recognize political realities. Once developed "Best Practices" will provide the current tools available to address the situation. However some follow-up to insure expected results are captured and follow-up to insure that advance technology once identified and proven is added to the list of "Best Practices". Once best practices are documented they can be employed. A single visit or an analysis using an inventory and/or operating data may identify the "Best Practices" to be used and expected saving for each village can be documented. This information can then be used to determine if the use of one or more the Best Practices will yield economic benefit either to the village or the state. Once this is determined an implementation schedule can be established together with funding would improve the situation.

However without adequate maintenance and sufficient revenue for renewal and replacement even a "Best Practice" will not be sustainable for long. Again, we can not just focus on just generation costs best practices will need to also include maintenance, operation, administration, and recognize political realities. This is the major problem we need to develop some method of solving the problem on a comprehensive and long-term basis. The development of a long-term affordable generation supply coupled with electrical interties is the logical solution for many villages along highways. Interties allow the least expensive generation source to be used by all that are interconnected. In areas where interties are not feasible, isolated systems, then best practices need to be established followed by the evolution to future best practices (i.e. fuel cells, wind/diesel hybrids, etc.)

APC have invited several villages to join our utility. In most cases the Division of Energy suggested this as a method to solve the problem. This has worked but has placed a burden on our existing customers and APC. Once the transfer occurs we (singly) become legally obligated to provide electric service that is safe and affordable and free from unreasonable interruption. This is not a responsibility we take lightly nor should anyone else. Further, as a rate regulated utility, the only opportunity for profit is a return of the invested plant. Since the amount of plant needs to be as little as possible to keep rates affordable, it provides a minimal opportunity for our employee-owners to enhance their value. In the case of small remote villages the traditional rate making practice creates a disincentive for company's like APC (IOU's) to re-invest its capital. An incentive based regulation may correct some of the disadvantages of the existing system.

Many of the villages are quite small and the additional costs associated with each village are many times higher than the residents can afford to pay. While it appears that we now have some assurance that PCE funding will continue at some level for many years. The ability to provide for renewals and replacements will remain difficult. Also, many of the villages are now getting systems to provide the residents with safe water and proper disposal of wastes. Again these are services that exceed the resident's ability to support it in a sustainable manner.

APC is regulated by the RCA. Once we accept the legal obligation to provide service we are bound. The services are very basic and badly needed and this is the very reason we have adopted several villages in the vicinity of our existing operations. However, the decision was made out of idealism rather than smart business. We do not regret these decisions but the extent that we can accept many more remain unresolved. As you can see a basic problem exists. The resident alone cannot support the services. If APC accepts a RCA certificate and the on-going responsibility for a large number of villages, it could have a large adverse impact upon our Company. For example, regulation or legislation could alter a portion of the funding (PCE). If the resident can't pay and PCE is either reduced or unavailable, APC has the obligation to provide service, even through no one can afford it.

APC is committed to working toward a solution that will insure that safe, good quality electric service, free from unreasonable interruption, at an affordable cost available to all residents of Alaska, regardless of where they choose to live.

To: Bob Grimm
From: Vernon Neitzer
December 8, 2000
Comments on AIDEA "Screening Report for Alaska Rural Energy Plan".

I have briefly reviewed the draft screening analysis. It is a well written analysis of rural generating conditions and many options to lower costs and improve system reliability. Here are my comments:

1. I am disappointed that fuel cells are not being considered for further study. While they do not meet the criteria for near term benefits, advances in the next 5 – 10 years may make diesel driven systems obsolete. How often will this rural energy plan be updated?
2. On page 6-2 the list of PCE utilities utilizing microprocessor relays does not include the many locations that AP&T utilizes this equipment.
3. On page 2-9 it is estimated that automated switchgear could improve fuel efficiency by 20 %. I believe this is number is much higher than any gains AP&T could achieve in their power plants. Proper generator sizing strategies will significantly reduce this number.
4. On page 5-12 is a list of cost estimates of hydroelectric power. Should Cordova's Power Creek and Humpback Creek projects be included?
5. Not mentioned in the evaluation is AP&T's practice of utilizing remote radiators with electric motor driven fans controlled by variable frequency drives. The engine driven radiator fans are an unnecessary parasitic load especially at light electrical loads in cold climates.
6. In addition to remote radiators, static battery changers improve efficiency by eliminating the typical belt driven alternator. This also results in decreased maintenance and improved reliability.
7. Our experience has shown that while 1800 rpm gensets are durable, the same diesel operating (derated) at 1200 rpm will show a significant increase in fuel efficiency.
8. No mention was made of utilizing oversized generators for improved load pickup capability, or special core materials to improve generator efficiency. We have just recently found as much as 2.6% efficiency differences between small generators of similar capacity and speed.
9. No suggestions were made addressing the major problem of maintaining power quality during starting of small motors.
10. AP&T utilizes fuel to fuel heat exchangers in the Tok facility to heat the fuel storage tank and utilize No. 2 fuel year around. It may be worthwhile to consider the installation of fuel storage heating systems in other locations to be able to utilize heavier fuels year around.
11. Thermal energy is mostly wasted from village diesel engines. AP&T is supplying jacket water heat to the schools at Mentasta and Eagle. The school in Tetlin also received heat until the powerhouse was replaced with a new power module that is equiped but not connected to the school at this time. The powerplant in Tok supplies heat to the nearby buildings.
12. No mention is made of the possibility of using river turbines for electrical energy. AP&T has an agreement with UEK Corporation to utilize the village of Eagle as a test site for a hydrokenetic generating system. If this technology proves successful, it could impact many Alaskan villages located on river systems.
13. While wind energy may be feasible on paper, finding accessible locations with acceptable wind regimes seems challenging to me.
14. The last two pages of my copy have a list titled "Bulk Fuel Deficiency Rankings by Community". I see a number of AP&T facilities ranked and do not understand what "deficiency" is being considered.

Alaska Power & Telephone
P.O Box 207 M.P. 1314
Tok, AK. 99780

Memorandum

To: Bob

CC: Eric, Doug C.

From: Don

Date: 12/15/00

Re: Comments on the Screening Report

Switchgear Automation - Pages 2-9

A 20% savings appears extremely high unless gensets are older, less efficient units. In this case, changing the gensets out to newer, more efficient units would provide better results. For most small communities, 500kW and less, the swing in load is primarily from summer to winter peaks. Local watchmen can switch to larger generators.

1200 Verses 1800 RPM Engines - Pages 2-3

Bettles is a good example. When the RPM was turned down on the CAT 3406 from 1800 to 1200, fuel efficiency increased from 11 to 14 kilowatts per gallon. A detailed comparison is lacking in this report. On 150 kW units and smaller, economics do not justify overhauling, but rather replacing the motor.

Maintenance Deficiencies

This report is not addressing a major problem, which is local responsibility in maintaining the plants. Are training programs in place? Can communities be penalized by reducing PCE Credit when they do not present evidence to prove scheduled maintenance and switching of engines to match load requirements? It is time for all communities to take some responsibility.

Fuel Price Strategies - Pages 3-13

Some communities cannot pay for bulk fuel deliveries. They order air-transported loads of approximately 3,200 gallons as needed. When they then fail to pay the vendor within a reasonable period, they pay the penalty of higher fuel prices.

Interties - Pages 5-17

I disagree with a blanket statement that interties, as a strategy should not be recommended for further evaluation. There are areas where interties make good economic sense. A detailed evaluation is needed, especially within those areas where natural resources are being developed. Eastern Interior Alaska is an excellent example. Had interties been constructed 20 years ago, they would have proven more efficient than constructing and maintaining individual power systems. In the absence of interties, smaller communities must continue to consider joining regional utilities thereby reducing O&M costs while enhancing reliability.

AVEC
ALASKA VILLAGE ELECTRIC COOPERATIVE, INC.

January 15, 2001

Mr. Dick Emerman
Alaska Energy Authority
813 West Northern Lights Boulevard
Anchorage, Alaska 99503

RE: Comments on Draft Screening Report for Alaska Rural Energy Plan

Dick
Dear M~~r. Emerman~~:

Thank you for the opportunity to submit comments on this draft report.

As you are probably aware, Alaska Village Electric Cooperative (AVEC) has used a number of the identified strategies over the years to improve overall operating efficiency. Our average annual generating efficiency has been raised from less than 7.1 kWh generated per gallon of fuel in 1975 to over 13.4 kWh in 1998. Similarly, we have reduced our internal (house) usage of gross energy generated from nearly 5% in 1975 to less than 2.5% in 1998. During the same time period, our system losses have been reduced from over 13% to less than 5.4%. The net result has been to more than double actual energy sales from under 6 kWh per gallon of fuel in 1975 to nearly 12.4 kWh in 1998.

This accomplishment was made through sizing and selection of diesel generator drive engines, efficient rotating generator ends, identification and elimination of resistive and parasitic loads in the power plants, purchasing high efficiency, low loss transformers and appropriate conductor sizing. These improvements have resulted in AVEC's fuel cost component falling to a value below the operations and maintenance cost component.

We offer the following comments on the draft Alaska Rural Energy Plan:

1. <u>Switchgear automation upgrades and real time economic dispatch:</u>
   There appears to be a blurring of the two subjects in the report. The advantages of each technology appear to be mentioned under each heading. There needs to be a clearer differentiation and definition of each technology.

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2. Cost of switchgear automation upgrades:
   Our experience is that the cost of installing automated switchgear upgrades is significantly higher than the installed cost figures cited in the report. Although efficiency improvements have, on occasion, resulted from the completion of switchgear automation upgrades, the cost of the upgrade has greatly overridden any resulting savings associated with efficiency improvements.

3. Real time economic dispatch vs. known engine life cycle cost:
   Real time economic dispatch systems tend to increase the load factor on the genset, resulting in increased generating efficiency. However, the time to overhaul is substantially reduced as load factors are increased. Without clearly knowing the life cycle cost of overhauling diesel engines, it is difficult to determine whether the fuel savings associated with real time economic dispatch offsets the reduced time to overhaul and the commensurate cost of completing overhauls and other associated maintenance.

Other possible areas that could receive additional attention in this report include:

1. Utilizing recovered heat to raise the temperature of stored fuel in order to allow the use of No. 2 fuel rather than No. 1 Arctic Grade fuel. Not only does No. 2 fuel cost significantly less, its btu value is also considerably higher, the combined result of which could reduce the cost of energy by more than the one cent per kWh identified as an evaluation criterion.

2. The combination of interties and wind power applied to geographically proximate communities such as Stebbins and St. Michaels, Toksook Bay and Tununak, St. Mary's and Mt. Village, in order to interconnect the two loads and to connect wind generator(s) could provide lower cost energy to the combined load of the two communities.

3. The possibility of a state or other entity coordinating bulk fuel bidding and purchasing for rural villages so as to bring pricing efficiencies to these communities. The small and myriad purchases in these communities leaves them at the mercy of market pricing that might be adding as much as 30 to 40 percent to what they might be able to achieve through a consolidated joint bidding process.

4. An evaluation of current design and construction practices with the perspective of possibly producing standardized and/or modularized designs for generation systems, tank farms and distribution systems. Such an approach could yield significant savings in the long term as operator training programs, maintenance programs and technical support services could be developed that would be transferable over a wide range of communities.

We are very pleased to see the efforts and resources devoted to developing a statewide energy plan that will identify technologies available to reduce the cost of generating electric energy in rural Alaska. We are anxiously awaiting a similar report addressing maintenance and operations and hope that it will promote a computerized maintenance management system as well as recommending additional training of remote power plant operators. We believe that these much-needed programs will help to bring down the high cost of operations and maintenance and improve reliability.

Areas of difficultly that could be addressed by the operations and maintenance study include:

1. Developing solutions to difficulties in properly inventorying fuel received and fuel stored, especially quantities of water delivered with the fuel.

2. Developing methods to assess the quality of fuel to assure that it meets standards.

3. Maintaining reasonable diesel engine life of newer, more highly stressed units.

4. Finding, training and retaining maintenance personnel capable of troubleshooting and repairing more sophisticated systems.

5. Overcoming the high cost of air transportation.

6. Overcoming the high cost of engine supplier maintenance technicians.

7. Identifying economical and environmentally compliant means of disposing of used lubricating oil.

In summary, the report appears to be an excellent effort to identify methods that may improve overall generation efficiencies in rural Alaska. The second part of the study, involving adequacy of operations and maintenance systems, is vitally important to achieving the overall goals of reducing high cost and improving reliability and we encourage the State of Alaska and its partners to continue its efforts to assist rural Alaska in bringing down the very high costs of generating and distributing electricity.

Sincerely,

Meera Kohler

Meera Kohler
President & CEO

MK: jpm

RECEIVED

KOTZEBUE
ELECTRIC ASSOCIATION

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Tel. 907-442-3491
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Bob Poe, Executive Director
AIDEA
813 West Northern Lights
Anchorage Alaska 99503

February 6, 2001

Dear Bob,

Thanks for the opportunity to provide comments on the Alaska Rural Energy Plan. I believe that the process will help with agency coordination to deliver services to rural Alaska in a more efficient manner. I look forward to discussing rural planning with you.

Sincerely,

Brad Reeve

Brad Reeve
General Manager
Kotzebue Electric Association

I have reviewed the draft copy of the "Screening Report for Alaska Rural Energy Plan". Following are comments, some as general discussion for the overall energy plan and some specifically for the screening report, with specific text changes. It is my intent to provide insight to working with rural Alaska, and its established utilities. I will say that the report does begin a reasonable discussion of various technologies.

This report is one of many in a long list of proposed energy plans. Other versions have been developed over the years with little impact. This report may unfortunately be starting out in the same manner. I was disappointed that the first review was done without the benefit of the recent circuit rider assessment that was not complete at the time of this draft. Without this information there is no overall evaluation of rural power plant status and no true characterization of the existing infrastructure. This leaves a huge hole in any report concerning rural electrical equipment.

From my reading of the report there appears to be a small number of people providing committee review with very little rural utility involvement. My understanding of the process from Bob Poe's November 24, 2000 letter to Eric Yould was that this was to be a stakeholders committee. Of the contacts named in the report there was only one utility that I recognized. To my understanding this utility was never officially contacted, but instead comments were gathered on an ad hoc basis. Not including the views of other utilities raises questions as to the validity of the report. There also appears to be limited attempts to utilize the experience of field personnel, service company staff and the plethora of mechanical and construction personnel that are available at rural sites. Their experience is invaluable in order to fully discuss various technologies and community capabilities.

I am also curious why there was apparently no effort to hold meetings in rural Alaska and little direct contact with rural utilities. A plan of this nature requires extensive input from those that may be affected. Trying to formulate a plan from Anchorage without utilizing the knowledge of the people doing the day-to-day operations will miss the mark.

The contacts listed in the back of the report appear to be primarily government. Unfortunately there are many examples of government selecting equipment without local input or buy down. This has created a long history of poor results in infrastructure development in rural Alaska. Most rural communities have experienced a number of ill-conceived attempts to introduce new technology. Many will question any future attempt unless there are efforts to first seek active community involvement.

A prime example was the early 1980's when government and other institutions placed 140 wind generators across the state. Government, primarily the state of Alaska took it upon itself to be the catalyst of wind deployment in the early 1980's with appalling results. Wind generators were deployed from Barrow to Southeast Alaska with all but a handful being defunct within a year. The technology could have worked, but what did not make sense was the application. There was little local involvement, no utility involvement, no maintenance planning, and no operational plan, just a plan for what has to be described as parachuting wind equipment all over the state.

The draft report states, that technologies would be dropped, if they do not meet a specific price threshold, this bothers me. The study seems to ask the wrong question. While economics are an obvious consideration, the fundamental question should be what is the best application of the technology. Or are there applications of a technology that will work. In the 1980s' in Canada, Ontario Hydro had committed to providing service to a number of logging camps. That utility took old steam engines, and increased the efficiency of the equipment by utilizing the heat and provided service to these camps. In this case it wasn't the technology, but the application.

One of the things that I do not see discussed in this phase of draft report is that no matter what the technology, for it to work it needs to be followed by proper management, engineering, maintenance and operations. There are villages in rural Alaska that have had their diesel equipment rebuilt or replaced every 3-5 years mostly due to a lack of planning and the assumption that the state would bail them out if they had a problem.

An example of a technology that has worked for Kotzebue Electric Association is the absorption ammonia unit that is used to produce ice with diesel jacket water heat. This was a project that was funded by the ASTF, the former AEA couldn't attract utilities to work with them on this project. KEA looked at it with a different approach. Our community needed additional ice-making capacity. The refrigeration units in town were old, required a lot of maintenance and were expensive to operate. The unit was designed for an application with high-heat exhaust boilers. The experience with exhaust boilers in many rural communities was poor; water quality was hard to control. The designer was told that we would not accept the equipment unless it was redesigned. This was done for two reasons: (1) to demonstrate a more reliable project using jacket water heat and (2) to allow further replication of the equipment in smaller per ton basis for smaller communities. There were several communities in the region that had a surplus of whitefish with no refrigeration. The result;

- For the past five years the equipment has produced all of the ice for the commercial fishing industry in Kotzebue.
- It has reduced station service load and lowered fuel usage by reducing radiator loads.
- We are currently investigating the use of the Baltimore Air Cooler that was part of the project to be used as an after-cooler with our largest diesel units that will increase fuel efficiency by 5-10%. This would translate to annual fuel savings of approximately 71,000 gallons, and reduce NOx emissions substantially by cooling exhaust gases.
- A second generation unit is being designed that will be smaller and produce a brine solution that will be fed across the street to set up fish and game processing and potentially a fish smoking operation and a subsistence food program for elders. This is an existing IRA Tribal building that has refrigeration, but was too expensive to operate with conventional compressors.

Had it been just a matter of economics, the Kotzebue absorption project would never have been built. It has helped save a limited fishery by offering low cost ice. The project is done on a shared basis with all of the fish buyers. With the understanding that the ice, which is only charged out at the cost of water and maintenance will provide savings that will be passed on to the fishermen. The economic value to the community far outweighs the evaluation of the original mission. Keeping the project alive will allow for a second generation of the technology. The second generation, through lessons learned, will meet the criteria for the original mission of producing ice at less than per ton cost of compressor-produced ice.

One area that needs to be included is an evaluation of community needs. To determine a basis for what is the best technology or approach requires an understanding of a community's infrastructure, growth potential, and expansion opportunities. Discussions of rural energy need to include power requirement studies for rural communities or the discussion of technology will lose meaning. To successfully deploy new technologies an evaluation of a community's dynamics is needed. Modeling of each community will be needed to complete this evaluation, i.e. will the community be needing a school addition, will the community be getting water and sewer, when is the next housing project. Can the residents of the community pay for the new services?

The discussion of economics does have its place but it shouldn't be used to completely exclude a given technology. Nor should a technology be excluded if it hasn't been used extensively. In Buckland, the Army Corp of Engineers is designing a $15 million dollar water and sewer system. There were several attempts at finding an appropriate technology or system including the Canadian haul system for water and sewer and a demonstration of home composting system with water haul.

The composting system was demonstrated in three homes and was apparently the most cost effective. The community actually voted to have the composting system installed. Agency officials didn't accept the composting system and began installing the Canadian haul system. All of the Canadian system installations are defunct. They broke down and were disliked by community members because the heat tape needed to keep the home systems operational increased the electric demand significantly, and the tapes were unplugged. The community will now be getting a traditional water and sewer system. The problem is how the residents will pay the estimated additional $150 a month bill. The village basically has little or no economy and very high unemployment. The point of this discussion is that community impact needs to be a part of the study when considering technology.

Sustainability will be the key to any technology. If there is no operational plan that teaches rural residents to run their own equipment, it just won't work. It may appear that the plan is established only to distribute money in rural Alaska and that has the potential for failure. At this point the expectation is that the state will continue to provide replacement equipment and maintenance at will. This will not allow the successful deployment of new technology, and does not promote responsible management. The state's circuit rider program was established during the Cowper administration to respond to a number of system failures and fires. The process has continued since then and has not to my knowledge established autonomy, regionalization or other systems to allow rural Alaskans to better handle their own equipment maintenance and replacement requirements. In many communities' circuit rider personnel just go back and rebuild the system when the equipment breaks again. I am hoping that other parts of the study address this issue.

Another consideration in this process is rural jobs and capabilities. In Kotzebue the tribal government is setting up a foam panel plant. The use of foam construction will reduce the cost of transportation significantly; by avoiding the cost of cubing that is associated with shipping bulk items. The panels will be produced at an estimated cost approximating 80% of standard construction on Anchorage. This is the type of project that improves local capability that works in rural Alaska. It also creates rural jobs with this new capability. The potential of a project like this promises significant building and energy cost reductions. The IRA, NANA, Maniilaq and KIC have formed a partnership that meets a local need and is an example of rural economic development at its best.

The energy plan should be aimed at improving local rural capability. An evaluation of favorable economic development needs to be included in the discussion. Can rural residents run the equipment? Will training be available? An evaluation of potential partnerships of all types needs to be included. Can partnerships be established with the local utility, city, borough, tribal government or other entities? There have to be stakeholders in this process.

One of the areas that I focused on immediately was the section on wind. I was disappointed for a number of reasons. One was that the author of the report made no attempt to contact our utility to request information and is using information that is dated, especially concerning fuel numbers. The recent escalation of fuel costs had a significant impact on the numbers. Fuel numbers have been available for months.

This section minimized the efforts of our cooperative and has greatly upset several of our board members. The goal of the KEA wind effort has been aimed directly at proving if wind technology will work in an arctic Alaska climate. By all industry standards, we have proven that it does. It was much more important to first answer the technology questions than to decide if the economics fit. The evaluation was performed primarily to prove or disprove the technological advantages of wind with the following in mind:

- Demonstrate that wind energy in significant penetrations could provide industry standard power quality.
- Demonstrate that arctic foundations would provide a stable platform for Alaskan wind projects
- Develop cost effective arctic foundations capable of working in permafrost
- Prove capability of freeze-back piling design
- Develop communications for SCADA
- Develop tilt-up tower design for small villages
- Develop safety & training program for wind systems
- Document operations and maintenance costs
- Assist other communities
- Develop high penetration wind projects that provide electric and thermal energy for the community
- Provide construction jobs for the local village corporation and rural residents
- Establish a high penetration 2-5 megawatt wind farm in Kotzebue
- Establish a cold weather technology center to demonstrate practical applications of the technology
- Reduce diesel consumption for KEA and the community by 300k to 500k gallons annually

The project has been operational since May 1997. After a debugging process, the turbines and associated equipment have been running extremely well. The initial turbines have operated for three winters with no significant maintenance.

Not being contacted and the subjective nature of the discussion concerning wind suggest a continued bias concerning alternative technologies. Seeing this it appears to minimize the efforts at Kotzebue.

<u>The following comments are directed at specific sections of the report on wind.</u>

The report excludes low interest loans in the scenario. Most of rural Alaska and rural America was built with low interest loans, which are still available. The majority of the state is served by public power entities that have low interest loans. In fact most of the small rural utilities were built with grants. There does not seem to be a reason to exclude low interest loans in the scenario. The majority of utilities in Alaska are public power and are eligible for low interest loans.

The report also excludes the REPI or Renewable Energy Production Incentive. KEA has received payments under the REPI program since the project was initialized. IOU's are eligible for the production tax incentive, which is tied to most of the large-scale projects in the country. To exclude this doesn't make sense.

"The economic benefits of wind power depend heavily on the wind resource and the cost of the displaced fuel." One of the greatest concerns of utility companies throughout the country is the rising cost of fossil fuels, which is not mentioned in this report.

It is okay to make a comparison of a 6.0 m/s resource to 7.0 m/s resource. That point was made in the KEA Economic report (page 36). However the wind speed at Nome is estimated at 6.5 m/s at 85 feet (approximate hub height of AOC turbine that is assumed in the remaining discussion.). In the report 6.5-6.8 m/s is stretched to 7.0 m/s. If the report is going to reference specific sites with specific wind resource it needs to indicate the measurement height. Kotzebue has 7.0 m/s winds if you put up a 50m tower. Based on the WECTEC report (which the author used for wind speed and energy production assumptions), Barrow, Bethel, and Cape Romanzoff all have average wind speeds of 7.1 m/s at 85 feet. Why wasn't a community with an actual measurement used? The paragraph should be replaced with the following:

The economic benefits of wind power depend heavily on the wind resource and the cost of displaced fuel. The current wind power installation in Kotzebue, where the average 85-foot wind speed is 6.0 meters per second, may not provide significant net benefits when diesel costs are less than $1 per gallon. However, net benefits have become significant with the recent increase in fuel costs. There are also numerous other sites in the region with higher winds that could provide significant net benefits at current fuel costs.

The assumptions in the GEC report included very conservative 1-% fuel cost escalation and 2% general inflation rates. If ISER adjustments are intended to reflect more realistic assumptions, why is the 1998-fuel cost of $0.94 per gallon not escalated in Table 5-15? If anything, the GEC rate assumptions should be increased *not removed*. This significant adjustment was not listed with the other ISER adjustments.

Rana Vilhauer of GEC set up the economic model presented in Tables 5-15 and 5-15. For Kotz23coltc (KEA 7-turbine project with ISER assumptions) it only takes a fuel price of $1.285 per gallon to meet the $0.20 present value savings criteria.

Table 5-16 shows that a 7 m/s project with ISER assumptions and a fuel cost of $1 per gallon does not meet the benefit criteria, but with a fuel cost of $1.5/gal far exceeds the criteria. The table could easily include a column showing the fuel cost level where the benefit criteria are met, which is $1.15/gallon, which is also the cost of fuel for KEA's last delivery.

Table 5-16 and Table 5-17 use a 14.9 and a 14 kWh per gallon figure for efficiency. The number that should be used is one that more averages the kWh per gallon efficiency of rural Alaska. Larger power plants and those with electronic injection systems are the only systems that achieve these efficiencies.

A discussion and potential cost for the reduction of diesel storage should be included. There are a number of communities facing growth that will require additional fuel storage. .

There should be further discussion of technology improvements with wind. The kWh cost of wind equipment continues to drop across the country. KEA is in the process of improving the economics of wind technology that fit Alaska by working on the following:

- <u>Blade pitching</u>; KEA is currently doing power curve testing with the US Department of Energy Turbine Verification Program (TVP) to establish the optimal pitch for better energy capture
- <u>Slow starts</u>; KEA is currently working with the turbine manufacturer on issues of slow starts due to cold weather, several solutions being tested will produce better energy capture

- Foundations; KEA is in the development phase of a third design of arctic foundations, foundations are one of the area's where there is great potential for reducing cost
- New blades; KEA will be adding 2 additional turbines with fiberglass blades that recently passed testing at the National Renewable Energy Laboratory. These blades are lighter and will produce more energy

KEA has also developed systems for oil changes, working platforms, safety equipment and training that will further reduce operating and maintenance cost. Beyond this we have produced reports for the National Rural Electrification Cooperative Association-Cooperative Research Network on power quality, and for the US Department of Energy/EPRI TVP all of which are intended to improve the operation and economics of wind as a technology.

The issue in part is that at best economics provide a snapshot of a technology. Technology on the other hand is not static. To try to base all technology assumptions on economics makes little sense. The draft report does show a lack of knowledge about how utilities were developed in areas of rural America that more urban utilities found uneconomic to serve. The Department of Agriculture has been funding utilities with low interest loans for decades. The economics would not have worked without them.

On a purely economic basis very little makes sense in rural Alaska. However very little made sense in electrifying rural America and it wouldn't have happened without FDR's decision to create REA and offer low interest loans. To base a plan strictly on economics will not create any revolutionary thinking. Placing technologies in a box and saying this one works, but this one doesn't because the numbers fit or don't fit does not lead to creative thinking. I do not see it creating new solutions for rural Alaska.

I do believe this effort holds great potential. It has started a process of having major agencies act in a coordinated manner. I only hope this evaluation goes a step further. It needs to involve a greater rural voice that will believe in the process.

Brad Reeve
General Manager, Kotzebue Electric Association

Alaska Native Tribal Health Consortium
Department of Environmental Health and Engineering
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Telephone: (907) 729-3600
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January 9, 2001

Dick Emerman
Alaska Industrial Development
and Export Authority
813 Northern Lights Blvd.
Anchorage, Alaska 99503

Dear Mr. Emerman:

Re: Comments to the "Screening Report for Alaska Rural Energy Plan"

The Alaska Native Tribal Health Consortium (ANTHC) appreciates the opportunity to comment on this report. Within the ANTHC, the Department of Environmental Health and Engineering (DEHE) has a significant role in providing water and sewer facilities in Native communities throughout Alaska. In an era of rising energy costs we are very much aware of the importance of energy efficient community facilities, in particular water and sewer systems in rural Alaska. Over the years, the Indian Health Service and now the ANTHC, DEHE have been involved in many projects utilizing waste heat or other sources of alternate energy.

The "Screening Report for Alaska Rural Energy Plan" identifies many factors affecting electrical and fuel costs. After review of the report, we have some specific comments to Section 7.3.2 , Waste Heat Recovery Systems.

In general, although this section identifies waste heat as having potential and deserving further study, in our opinion does not fully describe its potential benefits or current utilization by utilities.

1. The study should add the potential heat recovery from utilizing diesel engine exhaust. As a rule of thumb on diesel engines, exhaust and coolant systems, if properly designed and engineered have about the same potential recoverable heat energy. Of the heat content put into a diesel engine, (fuel consumed), an estimated 75-80% of this heat content is recoverable heat or electrical energy. Including exhaust heat recovery adds significantly to the amount of heat available and its quality (higher temperature). The pros and cons of using exhaust heat recovery can be included as well.

2. 100,000 BTUs of available waste heat is equivalent to one gallon of fuel oil displaced to the user. The report underestimates this conversion factor, the analysis is not complete without

taking this into consideration. For a user of recovered heat, to produce the equivalent of 100,000 BTUs, a gallon of fuel is burned, considering that the normal efficiency of a hot water boiler is about 75%.

3. Heat loss between the heat source and user is less than 15% routinely. A 5% number would be more realistic for estimates.

4. In this Section, 7.3.2, additional study is recommended on the utilization of waste heat recovery from diesel engines in rural Alaska. This effort will help document actual benefits and experiences.

5. This section refers to fuel oil at a cost of $1 per gallon. We would like to see calculations using more realistic costs and benefits for the users of the recovered heat. Fuel oil for some water utilities is costing more than $3 per gallon this year.

6. In Alaska, there are a large number of diesel engines with heat recovery equipment in place. The study barely mentions the current application and investment in place. Some mention of the current status needs to be made.

7. Heat recovery can have a benefit on diesel engine cooling. There is a collateral benefit to the overall "fuel to energy" conversion process with more efficient cooling of the engine. This can be significant, please include this benefit in the calculations.

The ANTHC recommends there be some discussion of the need for an "Energy Audit Program" for rural water and sewer utility systems. Water treatment plants, pump houses and related facilities use a lot of energy when operating properly, but if the facility is not managed well, energy can be wasted and high costs accrued by the community.

The ANTHC, DEHE and the community utility systems it works with will benefit from a better understanding of energy utilization and costs. We would like to contribute to this understanding as the Phase II portion of this study is carried out. We strongly support continued study and development of waste heat utilization and more efficient energy utilization. Please include the ANTHC, DEHE as a resource of information for that purpose.

Sincerely,

Art Ronimus, P.E.
Environmental Engineer
Consultant

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT

REGULATORY COMMISSION OF ALASKA

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February 8, 2001

Mr. Robert Poe, Jr., Executive Director
Alaska Industrial Development and Export Authority
813 West Northern Lights Blvd.
Anchorage, AK 99503

Re: Our comments on the report "Screening Report for Alaska Rural Energy Plan – Draft, November 2000"

Dear Bob:

Thank you for the opportunity to comment on the draft Screening Report for Alaska Rural Energy Plan, dated November 2000.

We have also reviewed the draft screening report from our viewpoint of certificating rural power utilities, and setting just and reasonable rates.

As a rate-making organization, we encourage good utility practices strictly through the setting of rates. Specifically we allow and encourage utilities to include the costs of technologically sound systems within their rate base. In the case of operating expenses, we review utility revenue requirements to allow all prudently incurred costs for the generation and delivery of electricity to be included in rates.

Thus we have strong interest in the screening process at hand, since it clearly focuses on strategies and technologies that utilities could use effectively in providing just and reasonable rates. We confine our comments to the structure of the screening process as it relates to our regulatory responsibilities, but do make two comments that are of a technical nature.

While we certificate all public utilities in the state, we economically regulate, or set rates for 35 of the 127 certificated utilities in the State. We do process all Power Cost Equalization Applications for both regulated and unregulated utilities in the state. There are thus a significant number of utilities that set their own rates.

We note that there is a separate process ongoing in viewing Operations and Maintenance Practices of rural utilities. I have been participating in that process along with our economist Antony Scott. What is important here is the linkage between the two processes. Clearly, new technologies will yield the greatest reduction cost of power, when they are applied to a properly managed and maintained utility.

Impressing new technologies on a poorly run utility is a little like building a nice home without a foundation. Thus O & M improvement must be an intrinsic part of this technology assessment.

While the report assumes that a utility will "clean up its act" prior to investing in a new technology, we feel the linkage should be clearly stated in this screening report. New technologies should not be applied until pre-existing operations and maintenance problems are resolved. Such a declaration will make the presentation much stronger, and in the end, more useful to the utility that makes use of the report.

We view investments in plant as a vital part of utility management. Timely investments in new equipment and retirement of less efficient equipment are vital to every utility in Alaska. Knowing what technology to embrace, and what to buy to replace aging equipment, or to fulfill a new need, is central to good management and achievement of low rates. We see the Screening Report as something that will help our State's utilities make these decisions.

Utilities need a practical document that lays out current experience and economics of available technologies. This can be the first stop in a process for utilities to view their specific situation, and make informed choices on system upgrade and expansion. We think that this document could helpful to utilities and their suppliers.

Clearly the approach the authors take in requiring candidate technologies to pass muster economically fits well with our mandate to ensure just and reasonable rates. We regularly disallow imprudent or improper investments into a utility's rate base. The well run utility will likely view available technologies/strategies in the same light as the report. The technologies that don't make it past the report screen likely won't make it with the properly managed utility either.

We wish to amplify what we see as valid criteria for screening technologies. The successful candidate technology must:

- Lower overall costs of operation of the utility;

- Have some track record of trouble free operation, and have known maintenance and trouble shooting characteristics, such that costs for maintenance can be accurately estimated;

- Match complexity of operations and maintenance with the capabilities of the utility's organization, and

- Provide a minimum rate of return on investment at least equal to the utility's target rate of return.

We note that there are any number of grants funded technology projects which have been approved without this economic viability screen. These projects amount to applied research projects in the field for the first time. Utilities have gone on the rocks with some of the projects, when participation agreements between funding agencies and the utility did not adequately protect the utility from cost over-runs.

On the other hand, some applied research projects have been successfully embraced by utilities without harming rate payer interests.

We do support the participation of utilities in these research projects, since in many cases, the only way to find out if an unproven technology/ strategy works is to try it out in the real world. But we have the following caveat for this support – <u>for any given applied research project, the rate payers must be completely insulated from any down side cost effects of an untried technology not performing as expected</u>.

We also have two specific comments on the report to present to you.

<u>Item No. 1:</u> *Report Section 2.3.2 Distribution System Improvements*

Agree with first sentence in last paragraph on Page 2-13. However, there is no analysis shown that supports the decision not to recommend these strategies for research beyond this screening analysis.

One concern is that the authors appear to rely on the system loss data provided by PCE data the RCA processes. The report states:

> *Based on these data, the average level of system loss is 13 percent, and the median level of system loss is 12 percent. The average falls to 12 percent if the data points are removed where system losses are zero or below, or 35 percent or higher. (These data points could be removed based on the assumption that they reflect monitoring or reporting errors.)*

In a footnote, the report goes on to say

> *A better approach would be to investigate utilities that have very small or very large system losses to determine the actual causes.*

We feel that the system loss data from the PCE filings may not give an accurate reflection of actual system losses. The data varies significantly between filings, and we are concerned that metering difficulties at the utility level may be seriously skewing the data. System loss can be anywhere from the generator to the rate payers meter.

During the teleconference held on December 15, 2000, we learned that one of the economists on the consultant team had reviewed the tabular data that was made available to them, and had derived his conclusions from a statistical analysis of this data.

In fact, the authors state in the last sentence on page 2-13

> *However, the strategies could be implemented by rural utilities as part of an effort to improve efficiency and reduce costs.*

Prior to dispensing with this area of discovery, it may be prudent to have the subject of system loss reviewed by a competent electrical engineer, and a better assessment of actual losses can be made. While the authors appear to regard it as an O & M item, lowering of line losses may involve significant capital expenditure, and as such could be better considered as both a technology or strategy issue and an O & M issue.

Item 2: *Regarding the treatment of rural power systems as a single category.*

The authors approach the cadre of State rural power systems as an amorphous block of energy systems upon which new technologies and design strategies are attached.

The rural power systems are different, and tend to fall into discrete categories each with special problems. Very small utilities with 75 to 100 KW peak loads have special needs that revolve around simplicity, basic redundancy, and a rather direct connection between large load and generator capacity. In the rural centers of the state, systems are larger, generators and distribution systems are larger, with difficulties specific to their class. The O&M capabilities and needs of very small systems also vary considerably from larger rural centers. O&M capability should be addressed as a specific issue. Development of staff capability will be achieving O&M improvement.

We think the correct strategies and technologies for "large" and "small" rural utilities to reduce costs of power and improve reliability can be distinctly different. The authors should consider diverse nature of our State's rural utilities and give more specific recommendations on where technologies and strategies will see success.

Closure:

Please feel free to contact us should you have questions. We look forward with the continuation of this important energy plan.

Very truly yours,
Regulatory Commission of Alaska

G. Nan Thompson

Nan Thompson
Chair Commissioner

Copper Valley Electric Association

Copper Valley Electric Association, Inc.

P.O. Box 45 • Glennallen, Alaska 99588 • Telephone: 907-822-3211 • Facsimile: 907-822-5586 • Valdez: 907-835-4301

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January 10, 2001

E-mail: wilkinson@cvea.org

Mr. Robert Poe, Jr., Executive Director
Alaska Industrial Development and Export Authority
813 West Northern Lights Boulevard
Anchorage, Alaska 99503

SUBJECT: Review of Draft Screening Analysis

Dear Mr. Poe:

Thank you for the opportunity to comment on the Draft Screening Report for the Alaska Rural Energy Plan. My congratulations to the project team for developing a comprehensive, informative report.

By way of general comment, it seems the analysis lacks a clear definition of rural Alaska. The sole reference to Copper Valley Electric Association as a rural utility is found in Section 5.3.7, where combustion turbines are discussed. I believe it is appropriate to clearly define rural Alaska in the document.

The following general comments and observations address the strategies for advancing to the next stage of the Energy Plan, which are summarized on Table 1-3 (page 1-6).

CVEA clearly understands and routinely employs the benefits of technology in our generation, transmission, and distribution system. Having said that, we also understand the practical realities of operating and maintaining newer technology. At a minimum the final study should address the following issues.

- Costs of future replacements and upgrades resulting from obsolescence.
- Costs to train utility personnel to operate, maintain, and troubleshoot equipment or, in the alternate, to retain consultants to perform these tasks.
- Reliance on technology can sometimes result in a loss of the practical knowledge to operate utility systems when that technology does not work.

- Prior to making significant investments in technology in rural Alaska, geographical, social, and managerial barriers should be thoroughly assessed and plans should be put in place to ensure the investment will be long lasting.
- Section 2-2 discusses 1,200 rpm versus 1,800 rpm engines; however, it omits a discussion of whether improved maintenance of existing units is a viable strategy to reduce the cost of electricity in rural Alaska.

CVEA agrees that space and water heating and end use conservation strategies have the potential to reduce the cost of electricity for specific consumers. However, we believe those reductions could result in an overall increase in the unit costs per kwh, thus leading to required increases in a utilities' overall revenue requirement.

I appreciate the opportunity to comment on the Draft Screening Analysis. If I can provide further information regarding my specific comments, please call on me.

Sincerely,

Robert A. Wilkinson

Robert A. Wilkinson
Chief Executive Officer

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Galena Alternative energy considerations.

Galena produces electricity using diesel engines with AC generators. There are 6 engines with the following production, 1 -850kw, 4 -750kw and 1 –450kw. The peak loads vary from 1600kw in the winter to 900kw in the summer.
We are in the process of installing automated switch gear with recording devices so that we can continuously monitor the fluctuations in the demand. However, from past practice we know that in the summer we normally operate one of the large engines and the small one and in the winter we operate two large ones and some times have 3 engines operating. The plant generated more than 9,000,000kw's last year so the average year around load is 1030kw/hr.

Options

1. Methane gas. The City in cooperation with USGS has conducted some seismic testing to determine if it feasible to explore for Coal bed Methane. We should have results in January 2001.
2. Coal. There is an exposed coal seam about 8 miles from Galena on Doyon land. Both Doyon and USGS have evaluated the coal and determine it is high quality, approximately 11,000 BTU per pound. At present there is no determination on the quantity of coal that may be available. Some of the seismic work was in the area some we hope to have additional information when that work is completed.

   Because economies of scale are so critical to a coal facility, we feel it would be necessary to include the Air Force Base in any decision where coal was to utilized. Currently, we sell more than 60% of the Electricity we produce to the AF. In addition the AF uses oil fired steam boilers, which send heat through their utilidors to heat their buildings. They consume about 700,000 gallons of diesel per year. Therefore, it would be necessary to have a coal facility that could produce 10 to 15 million kw per year and also supply enough steam heat to replace most of the AF Diesel fuel requirements.
3. Solar. Solar only has possibilities with some subsidy. Using the numbers in the screening report I would propose installing100kw's of solar power. At $7000 per kw that equals $700,000. Assuming 60% grant funds would leave about $315,000 to amortize or about $25,000 per year. The estimated 5 cents operating costs is 22 cents below our current rate. The screening report estimates annual efficiency at 17%, with an AC/DC conversion loss of 10%. Using these numbers we would produce (90kw X 1500hours) 135,000 kw per year X .22 cents (per kw savings) equals $29,700 in savings per year. Because of our load factors we should be able to operate on a single generator during portions of the summer months and thereby save on engine wear.

   The City also utilizes the waste heat from the diesel engines. During the winter months we are nearing the capacity of the waste heat system. Which leads us to conclude that if we produced much solar in the winter we have to use oil fired boilers to heat our buildings. Since we are using nearly 50% of the diesel BTU's in the winter and in the summer need to run fans to dissipate the extra heat we feel that having solar panels only work in the summer is not a detriment.

Natural Gas. I am assuming that there will be a natural gas pipeline along the same corridor as the Oil pipe line as far as Fairbanks. We would like some analysis of either barging compressed natural gas down the Yukon River or a pipeline to serve the same area.

Marvin Yoder

City Manager

City of Galena, Alaska

AREC A
Alaska's Electric Association
"Electric Service for 556,000 Alaskans"

January 31, 2001

Mr. Robert Poe, Jr.
Executive Director
Alaska Industrial Development & Export Authority
813 W. Northern Lights Blvd.
Anchorage, AK 99503

REFERENCE: Comments to the Rural Energy Plan – Draft Screening Analysis

Dear Mr. Poe:

This is in response to your invitation to provide comments to the Draft Screening Report for the Alaska Rural Energy Plan. It is our understanding that this Draft is one component of the overall plan being worked on by other study participants. This matrix approach to the overall plan appears to provide a good "building block" for addressing a very complex subject for which the solution appears to be a mix of technology innovations, utility structure reorganization, and local accountability. So often these energy plans focus on "energy innovations," most of which are non-credible in rural Alaska, with no imposition of local financial or operational discipline.

We agree with the screening criterion that has been utilized in the study and the desegregation of subsidies from that analysis. While we believe that other intangibles may ultimately enter into final development decisions, it is important to establish a common yardstick from which to make comparative judgments.

We agree with the general assessments of the various alternative energy technologies and in particular that diesel internal combustion and wind generation, where appropriate, hold the greatest near term promise for uninterconnected small villages in rural Alaska. Rural Alaska suffers from a lack of economy of scale. Nevertheless, aggregation through transmission interconnection is rarely economically feasible either, as the cost of the transmission lines must be accounted for in the ultimate cost. While there are no other alternative energy technologies that can be summarily endorsed for rural Alaska, individual projects may prove feasible on a community-by-community basis. This is often true of small hydropower where site conditions and proximity of the village to a proposed powerhouse can result in unit costs ranging from an attractively low $1,500 per installed kilowatt to in excess of $10,000/ kW and economic unfeasibility.

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While some rural villages have been fortunate to benefit from local projects such as hydropower, most have found that diesel generation provides the most economical energy. This is because there is a fuel transportation network throughout rural Alaska that can accommodate diesel fuel, the capital cost of the generation is low, and there is a general availability of skilled operators who also have the knowledge to maintain the plants. We agree that diesel generation is the most probable near and intermediate term generation resource for rural communities.

While there has been a preoccupation with finding alternatives to diesel generation for rural Alaska, diesel generation technological advancements have been such that most alternatives cannot compete. The fuel efficiency in the 51-village AVEC system has more then double over the past 25 years resulting in a nominal cost of power today being nearly the same as what it was in the year 1980. As pointed out in your Draft report, imposition of new control technology on other village diesel plants would result in similar savings. Realization of these benefits requires that the generators be properly sized for the villages and that sufficient operational records be collected about the community's electrical usage to properly design the automated control equipment.

In short, we believe that the Draft energy plan is correct in its cost reduction strategies. Nevertheless, this is only part of the equation. The Rural Utility Operations, Maintenance, and Management Study presently being conducted by the Institute of Social and Economic research may well hold the key to affordable electricity in rural Alaska in consonance with the strategies presented herein.

Thank you for the opportunity to comment on this portion of the Rural Energy Plan.

Sincerely,

Eric P. Yould
Executive Director

EPY/ab

NOTES FROM ENERGY PLAN TELECONFERENCE
DECEMBER 15, 2000
REVIEW OF DRAFT SCREENING ANALYSIS

Bob Grimm (AP&T) –

Wants report to be more location specific. Name communities. e.g. interties. Maybe interties in southeast tend to be feasible even if interties in western Alaska are not. He doesn't want the report to conclude that interties do not result in significant benefit to a significant # of people in the near term. He apparently thinks they do.

Loren Gerhard (Southeast Conference) –

Agrees with Grimm. Wants to revise bottom of page 5-17. Caveat: at least for southeast alaska, there is an intertie proposal that could provide significant benefit to rural communities in combination with some larger communities. He thinks the connection with larger, non-rural communities makes a difference in their viability. Shared capital costs with larger communities. Recognize that viability depends in some measure on federal grants. Say something about federal funds changing the cost-benefit equation from the state or local perspective.

Doesn't want to see something that sounds like interties are "absolutely inappropriate" or don't deserve any attention.

Bob Grimm –

skepticism about switchgear improving fuel efficiency by 20% -- thinks the report analysis is exaggerated. Maybe closer to 4%.

He will also send in written comments.

Marvin Yoder (City of Galena) –

Communities that already have efficient diesel power plants don't get much of anything from this report. He questions some of the alternative energy assumptions. Wants to see alternative energy projects judged with 50% govt grant subsidy included.

Eric Yould (ARECA) –

Wants to hold open the comment period. It was agreed that written comments can be submitted until mid-January. He wants the economic criteria and assumptions stated together clearly towards the front of the report. (e.g. discount rate, fuel escalation, heat rate of machines etc.) Have we used some sort of standard diesel efficiency in our evaluations?

Jim Strandberg (RCA) –

PCE data on line losses is very inconsistent. Just can't tell much of anything from the data, i.e. whether losses are very significant or not. Maybe we should take some test cases and determine ourselves in the field rather than rely on the PCE data. Could be important to get this issue right.

[Dan Rogers indicated at this point that he thought Hart Hodges did most of the work on line loss data.]

Meera Kohler says AVEC has been working to reduce line losses and their average now is about 5-6%. They take a look when losses exceed 7 or 8%. In many small communities, there are "secondary services off a single transformer." Long runs with voltage problems.

Someone else – oversized transformers.

Dan Salmon – sometimes the line loss data actually includes station service / powerhouse consumption.

The definition of "net generation" varies and probably should be standardized.

Meera Kohler (AVEC) –

Would like a section in the report on the link between the world cost of fuel and the delivered price in rural AK, and consider whether a pool could be established that creates a reserve for evening out fuel price fluctuations. Maybe it could be started like a "TAPS" fund or a "470" fund. A consortium of the State and oil companies might agree that, when the price of oil gets above a certain level, some amount (1 cent per barrel?) would go into a reserve fund that would be used to offset high retail prices.

Lamar suggested the possibility of borrowing funds instead of initiating with grants. When the oil price is high, maybe funds are borrowed (from the State?) to offset high retail prices but paid back when prices decline.

Scott Waterman (AHFC) –

Debt could also be used to finance end use conservation programs. Pay back the cost of the measures from the energy savings. e.g. a revolving loan fund.

Bob Grimm –

Possible that fuel price fluctuations could be evened out by purchasing fuel futures. Might be used to hedge against sudden price changes, but unsure. Might hedge the "fuel price risk"(?)

Meera Kohler said that the Western Alaska Fuel Coop looked at using fuel futures to help levelize fuel costs. It did look like speculating in the market. Sometimes they'd win and sometimes not.

We need to consult with some people and include what they find out in the next version of the report.

Dan Salmon (Igiugig Electric Co.) –

Talked about wide range in O&M effort among rural communities due to lack of money, skill, and/or interest. Automated switchgear might produce high savings in some communities because they do such a poor O&M job – e.g. operating oversized unit unnecessarily.

O&M should be standardized, or at least O&M standards should be set.

Art Ronimus (ANTHC) –

ANTHC interested in waste heat recovery systems. He thinks the potential is underestimated. The efficiencies shown in table 7-8 are not accurate. Should include exhaust heat. Water and sewer facilities are energy intensive, including need to keep the water heated. Waste heat recovery systems could be funded as part of a water and sewer project capital cost. Net revenues from sale of heat can help to keep the utility viable. He will send written comments.

Bob Grimm –

Waste heat can also be used to heat bulk fuel and avoid having to purchase diesel #1.

Nushagak also has a couple of heated tanks.

Jim Strandberg –

General remarks about rural utility data and how to organize it.

Scott Waterman –

AHFC has some extensive information on water and sewer projects in Canada. The Canadians will be in Anchorage at the end of March for an AHFC-sponsored conference at the Sheraton. "Cold Comfort" conference.

On site, individual waste water systems (in contrast to centralized systems) could be an element of end use conservation programs in that pumping and heating costs could be significantly reduced. Each one could serve maybe 3-4 houses. Although heating and pumping costs to the City would be less, the homeowner's energy bill would clearly be higher.

Someone wants phase 2 analysis to show actual cases with actual communities identified.

Appendix B—Power Outages: Service Interruption Data

Total average outage hours per customer by cause for 1995

Region/Community	Utility	Power Supplier (hrs/yr./customer)	Extreme Storm (hrs/yr./customer)	Pre-Arranged (hrs/yr./customer)	All Others (hrs/yr./customer)	Total (hrs/yr./customer)	Notes
SOUTHEAST							
ANGOON	THREA	0.35			8.08	8.43	
CHILKAT VALLEY	THREA	0.65				0.65	
COFFMAN COVE	COCO		0.80		0.50	1.30	
CRAIG	AP&T		0.60	0.10	3.50	4.20	
ELFIN COVE	ECU			7.00	10.00	17.00	
HAINES	HL&P	2.50	0.50		0.50	3.50	
HOLLIS	AP&T		1.30	0.10	0.50	1.90	
HOONAH	THREA	0.46		1.21	0.31	1.98	
HYDABURG	AP&T				0.20	0.20	
JUNEAU	AEL&P	1.00			0.89	1.89	
KAKE	THREA	0.16			1.31	1.47	
KASAAN	THREA	2.59		0.55		3.14	
KETCHIKAN	KPU	0.22	0.03	0.05		0.30	
KLAWOCK	THREA	0.56			0.46	1.02	
METLAKATLA	MP&L	3.67			8.50	12.17	
PELICAN	PUC			0.60		0.60	
PETERSBURG	PMP&L						DATA NOT AVAILABLE
SITKA	SED						DATA NOT AVAILABLE
SKAGWAY	AP&T			0.20	0.70	0.90	
TENAKEE SPRINGS	TSU		4.00	3.00		7.00	
THORNE BAY	TB	2.00		2.00		4.00	
WRANGELL	WML&P					0.00	DATA NOT AVAILABLE
YAKUTAT	YPI	2.00		0.25		2.25	

1995 Service Interruptions (Outages)
(Page 2 of 5)

Total average outage hours per customer by cause for 1995

Region/Community	Utility	Power Supplier (hrs/yr./customer)	Extreme Storm (hrs/yr./customer)	Pre-Arranged (hrs/yr./customer)	All Others (hrs/yr./customer)	Total (hrs/yr./customer)	Notes
SOUTHCENTRAL							
ANCHORAGE	CEA	4.35		0.04	1.37	5.76	
ANCHORAGE	AML&P	0.02	0.01	0.03	3.06	3.12	
CHITINA	CEI						DATA NOT AVAILABLE
CORDOVA	CEC	0.44	0.04	0.31	1.41	2.20	
GLENNALLEN	CVEA	0.01	0.16	1.30	4.13	5.59	THESE VALUES REFLECT OUTAGES IN BOTH COPPER RIVER BASIN AND VALDEZ
HOMER/SELDOVIA	HEA	0.80	0.90	0.10	2.80	4.60	
KODIAK/PORT LIONS	KDEA	0.60	0.52	0.14	1.95	3.21	
LARSEN BAY	LBUC	5.80		5.50	5.50	16.80	
OLD HARBOR	AVEC	3.67		5.50		9.17	
OUZINKIE	OU					0.00	
PALMER	MEA	2.07	0.78	0.10	2.50	5.45	
PAXSON	PLI			2.70		2.70	
SEWARD	SES			0.45	1.03	1.48	
VALDEZ	CVEA	0.01	0.16	1.30	4.13	5.59	THESE VALUES REFLECT OUTAGES IN BOTH VALDEZ AND COPPER RIVER BASIN

1995 Service Interruptions (Outages)
(Page 3 of 5)

Total average outage hours per customer by cause for 1995

Region/Community	Utility	Power Supplier (hrs/yr./customer)	Extreme Storm (hrs/yr./customer)	Pre-Arranged (hrs/yr./customer)	All Others (hrs/yr./customer)	Total (hrs/yr./customer)	Notes
YUKON							
ALAKANUK	AVEC	48.43		2.47		50.90	
ANVIK	AVEC	1.37		2.33		3.70	
BEAVER	BJU						DATA NOT AVAILABLE
BETTLES	BL&P			0.05	0.06	0.11	
CENTRAL	FNU	0.33		1.50		1.83	
CHEVAK	AVEC	0.80		0.25		1.05	
CHISTOCHINA	AP&T				0.30	0.30	
EAGLE	EPC					0.00	
EMMONAK	AVEC	10.53		2.83		13.36	
FAIRBANKS	GVEA	1.79	0.05	0.12	1.14	3.10	
FAIRBANKS	FMUS						DATA NOT AVAILABLE
FORT YUKON	GZUC	2.00	3.00	16.00		21.00	
GALENA	COG			2.00		2.00	
GRAYLING	AVEC	2.70				2.70	
HEALY LAKE	AP&T			7.90	12.90	20.80	
HOLY CROSS	AVEC	1.43		10.80		12.23	
HOOPER BAY	AVEC	9.03		19.75		28.78	
HUSLIA	AVEC	1.67				1.67	
KALTAG	AVEC	3.28				3.28	
KOTLIK	KC					0.00	
KOYUKUK	KEC						DATA NOT AVAILABLE
MANLEY HOT SPRINGS	MUC			1.40	0.60	2.00	
MARSHALL	AVEC	1.12		4.75		5.87	
MENTASTA LAKE	AP&T					0.00	
MINTO	AVEC	22.42		3.00		25.42	
MOUNTAIN VILLAGE	AVEC	3.23				3.23	
NORTHWAY	NP&L			0.10	0.20	0.30	
NULATO	AVEC	2.37				2.37	
PILOT STATION	AVEC					0.00	
RUBY	REC					0.00	
RUSSIAN MISSION	AVEC	1.63		2.00		3.63	
SCAMMON BAY	AVEC	2.60		7.58		10.18	
SHAGELUK	AVEC	0.37				0.37	
SHELDON POINT	SPEU						DATA NOT AVAILABLE
ST. MARY'S	AVEC	8.95		15.42		24.37	
TANANA	TPC			10.00	2.00	12.00	
TETLIN	AP&T	3.00			0.30	3.30	
TOK	AP&T			0.20	0.60	0.80	

ALASKA UTILITIES
1995 Service Interruptions (Outages)
(Page 4 of 5)

Total average outage hours per customer by cause for 1995

Region/Community	Utility	Power Supplier (hrs/yr./customer)	Extreme Storm (hrs/yr./customer)	Pre-Arranged (hrs/yr./customer)	All Others (hrs/yr./customer)	Total (hrs/yr./customer)	Notes
ARCTIC/NORTHWEST							
AMBLER	AVEC	10.87				10.87	
ANAKTUVUK PASS	NSBPL						DATA NOT AVAILABLE
ATQASUK	NSBLP						DATA NOT AVAILABLE
BARROW	BU&EC	0.85	0.15		0.40	1.40	
BREVIG MISSION	AVEC	1.13		1.33		2.47	
DEADHORSE	AUI	5.50				5.50	
DEERING	IEC					0.00	
DIOMEDE	DJU						DATA NOT AVAILABLE
ELIM	AVEC	0.25				0.25	
GAMBELL	AVEC	8.40		1.80		10.20	
KAKTOVIK	NSBPL						DATA NOT AVAILABLE
KIANA	AVEC	9.73		7.50		17.23	
KIVALINA	AVEC	6.67		0.50		7.17	
KOTZEBUE	KTEA	1.85		1.65	0.48	3.98	
KOYUK	AVEC	6.33				6.33	
NOATAK	AVEC	4.27		7.42		11.69	
NOME	NJUS						DATA NOT AVAILABLE
NOORVIK	AVEC	6.80		3.72		10.52	
NUIQSUT	NSBPL						DATA NOT AVAILABLE
POINT HOPE	NSBPL						DATA NOT AVAILABLE
POINT LAY	NSBPL						DATA NOT AVAILABLE
SAVOONGA	AVEC	95.83		3.50		99.33	
SELAWIK	AVEC	8.33		10.92		19.25	
SHAKTOOLIK	AVEC	2.92				2.92	
SHISHMAREF	AVEC	1.50				1.50	
SHUNGNAK	AVEC	6.87				6.87	
ST. MICHAEL	AVEC	16.67				16.67	
STEBBINS	AVEC	2.70				2.70	
TELLER	TEPC			0.25		0.25	
UNALAKLEET	UVEC	0.86			0.25	1.11	
WAINWRIGHT	NSBPL						DATA NOT AVAILABLE
WALES	AVEC	10.58		0.33		10.91	
WHITE MOUNTAIN	COWM				0.08	0.08	

Appendix C—Bulk Fuel Storage: Supplementary Documentation

MEMORANDUM STATE OF ALASKA

DEPARTMENT OF ENVIRONMENTAL CONSERVATION.
Facility Construction and Operation
Village Safe Water
555 Cordova St. 4th Floor
Anchorage, Alaska 99501

TO: Jim Childers, P.E. DATE: October 11, 2000

FROM: Mike Wolski, P.E - VSW Engineer SUBJECT: Chefornak Sanitation Boardwalk

Central Region of the Department of Transportation (DOT) is working with Village Safe Water (VSW) on the Chefornak Sanitation Boardwalk Project. DOT has allocated $1,380,000 in funding for construction of sanitation boardwalks, under project DOT-53444/STP-001(147). VSW has completed the design and previously submitted it. The $1,380,000 in DOT construction is part of a larger VSW project where VSW will be constructing other boardwalk, water, sewer, and landfill improvements. The total cost of the project, including sanitation boardwalk, will exceed $7,500,000.

VSW projects are cooperative projects with the community, whereby the community is the recipient of the funding and VSW is the technical representative that administers the project. In accordance with the Grant Agreement between VSW and the Community of Chefornak, the community has the option whether the project is to be constructed using force account labor or is to be competitively bid. The Chefornak Water and Sewer Utility Board represents the City of Chefornak and the Chefornak Traditional Council in matters regarding sanitation improvements. The Chefornak Water and Sewer Utility Board has elected to construct the sanitation facilities using force account labor. The attached resolution was adopted by Chefornak is support of a "force account project".

In addition to the $1,380,000 slated for DOT funded boardwalk, another $900,000 in boardwalk improvements is schedule be built with other funds, using force account labor. It will be more practical and substantially more cost effective to allow Chefornak to construct the DOT sanitation boardwalk improvements on the same project using force account labor.

As a prerequisite to the use of force account materials, labor and equipment, DOT/PF Procedure (DPDR) 05.01.070 (in accordance with 23 CFR 635.201 205) requires that the Director of Engineering, Operations & Standards issue a Public Interest Finding (PIF). The PIF is to be based on a determination of cost effectiveness. A PIF request must include a written analysis that addresses certain criteria found within the procedure. My request is that you issue a PIF, and this request is based on the following justification:

1. The estimated cost of construction by force account is substantially less than the

estimated cost to perform the work under competitive bid. I estimate that approximately $648,000 can be saved by building this project with force account methods.

As a basis of comparison, I have prepared a cost comparison between force account labor and contract construction. There are a few assumptions made when comparing the cost.

Assumption 1: Material and freight costs will be roughly the same between contract and force account jobs. In fact, one might find that the force account job can save money on freight because the force account job has other work being done, with more bulk to freight into Chefornak. Our latest bid quote for freight was $0.19 per pound. Last year's quotes were over $0.35 per pound. A contractor would have to be lucky to get a rate less than $0.35 per pound, and it would be unlikely that a contractor could beat $0.19 per pound.

Assumption 2: The speed of construction will be the same between contractor and force account construction. Residents of Chefornak are experienced in boardwalk construction, having built all the boardwalk currently in the community. Last year, they also constructed over 1,200 lft of new boardwalk, which is identical to the proposed DOT boardwalk.

Rather than compiling separate force account and contractor construction estimates, I prepared a cost comparison between the two. There are five main areas that distinguish force account labor from contract labor.

A. Mobilization and demobilization costs are reduced for a force account job. Since the community already owns all the necessary equipment to build the boardwalks, no additional equipment will be needed for construction. With an estimated weight of 41,000 lbs for the key components necessary for construction, the mobilization saving is $32,400.

B. The labor costs on a force account project are significantly lower than the labor costs on a contracted project because the community is not required to pay Title 36 Laborers' and Mechanics' Minimum Rates of Pay. A comparison for this project follows.

Position	Force Account	Contract

Foreman	$ 18 to $20/hr	$ 36.30/hr
General Laborer	$ 12 to $14/hr	$ 32.64/hr
Lead Carpenter	$ 16 to $18/hr	$ 36.30/hr
Carpenter Helper	$ 14 to $16/hr	$ 32.64/hr
Housekeeper/Janitor	$ 10 to $12/hr	$ 24.07/hr
Cook	$ 10 to $12/hr	$ 26.71/hr
Equipment Operator	$ 20 to $22/hr	$ 38.17/hr

Labor costs are roughly 217% higher on a contracted project. It is estimated that 19% of the cost of the Sanitation Boardwalk Project will be for labor, or $263,000 (using force account rates) versus $571,000 for contract construction. The estimated savings using force account labor is roughly $308,000.

C. There are no profit, overhead, nor bonding costs associated with a force account project as compared to a contracted project. Profit, bonding and overhead is estimated at 5% to 15% of the total cost of the Sanitation Boardwalk Project, or an average cost savings of $138,000.

D. Because the force account crew lives in Chefornak, it will not be necessary to bring in a camp for imported workers. There is no available housing for a contractor to rent a project camp. The cost for importing a project camp would cost $100,000. This cost is based on historical costs for setting up a project camp in Tuntituliak and projected costs for Chefornak.

E. Force account projects do not require performance specifications, bid documents, or full time inspection as required for a contract job. The project superintendent acts as a project inspector, with spot inspections performed by the VSW engineer. Both force account jobs and contract jobs require a project superintendent. The cost savings for not preparing specifications, not requiring bid documents, nor requiring an inspector is estimated at $70,000.

In summary, the total estimated savings on the proposed sanitation boardwalk project is $648,400 if the project uses force account methods as compared to contracting methods. Considering the total DOT funded portion of the project is $1,380,000, a cost saving of 47% will be achieved.

We are confident in our cost estimate for the force account construction. Our estimates are based on historical data obtained from the 1999 construction of 1000 linear feet of 12 ft wide boardwalk in Chefornak. The 1999 construction used VSW funding and other funds to build access improvements to a new water treatment plant site and well field.

The Community of Chefornak has requested that it be allowed to proceed with construction of the sanitation boardwalk project on a force account basis. A resolution passed by the Chefornak Water and Sewer Utility is attached. Local labor is available and willing to perform the work for the duration of the project, which is expected to last two construction seasons. The Chefornak labors have extensive experience constructing boardwalk. The local workforce has constructed the existing boardwalk infrastructure.

3. Equipment adequate for construction of the project by force account methods is located onsite. The equipment fleet consists of a Bobcat with a backhoe and Chance anchor hydraulic drive head, a JD350C with backhoe attachment, JD450 wide track dozer, a Hitachi EX300 backhoe, and various 4 wheelers and small trailers.

4. The impact of force account construction on the private sector in the geographical area is minimal. There are no private sector construction contractors in Chefornak. The nearest general contractor is based in Bethel, 100 air miles to the east of the community. There are no roads connecting Chefornak with any other community in Alaska.

Please consider these factors and make the determination that it is in the public's best interest to use force account labor, materials, and equipment to construct this boardwalk project.

Thank you.

Post-it® Fax Note 7671	Date	# of pages ▶ 7
To DEBORAH ALLEN	From KURT E	
Co./Dept. URS	Co VSW	
Phone #	Phone # 269-7601	
Fax #	Fax # 269-7509	

TION

TONY KNOWLES, GOVERN

269-7601
FAX 269-7509
555 Cordova St.
Anchorage, AK
99501

VILLAGE SAFE WATER

RECEIVED
JUL 12 2000

December 26, 1996

Attn: Jim Childers, P.E.
DOTPF Central Region
P.O. Box 196900
Anchorage, AK 99519-6900

Subject: **Request for Public Interest Finding -- Force Account Construction; Hooper Bay Sanitation Roads Improvement Project**

Dear Jim:

Enclosed is a memorandum describing my justification for building the Hooper Bay Sanitation Roads Improvement Project using force account methods.

Also enclosed are documents that support this request, including a cost summary of the force account work performed in 1996 on the Hooper Bay Solid Waste / Sewage Lagoon Upgrade Project, a manpower utilization and cost report, a detailed project accounting report, and Resolution No. 96-12-02 from the City of Hooper Bay requesting that the sanitation roads project be constructed on a force account basis.

If you have any questions or comments, please call me at 269-7601.

Sincerely,

Kurt Z. Egelhofer, P.E.
Village Safe Water Project Engineer

Enclosures

cc: City of Hooper Bay
Chuck Eggener, P.E.

MEMORANDUM

Village Safe Water | State of Alaska

555 Cordova Street, Anchorage, Alaska 99501

To: Jim Childers, P.E. | Date: December 26, 1996

From: Kurt Egelhofer, P.E. | Subject: Hooper Bay Sanitation Roads Project

Central Region of the Department of Transportation (DOT) is working with Village Safe Water (VSW) on the Hooper Bay Sanitation Roads Project. This project is included in the 1995-1997 STIP and the draft STIP with construction funding allocated for FY-97. The Legislative Act containing the appropriation for this work is referenced: 123/96/62/11. The $3,300,000 in funding will be used for the construction and upgrading of roads accessing sanitation facilities currently under construction. VSW will administer the work as a part of a three year project that will construct a solid waste disposal site and a wastewater lagoon. These sanitation improvements are included in the community's Master Plan. The total cost of the project, including sanitation roadway construction work, will be $5,253,000.

VSW projects are cooperative projects with the community, whereby the community is the recipient of the funding and VSW is the technical representative that administers the program. In accordance with the Grant Agreement between VSW and the City of Hooper Bay, the community has the option whether the project is to be constructed using force account labor or is to be competitively bid. The City of Hooper Bay has elected to construct the sanitation facilities using force account labor. It will be most practical to allow the City of Hooper Bay, with VSW assistance, to construct the sanitation road improvements on the same project using force account labor.

As a prerequisite to the use of force account materials, labor and equipment, DOT/PF Procedure (DPDR) 05.01.070 (in accordance with 23 CFR 635.201-205) requires that the Director of Engineering, Operations & Standards issue a Public Interest Finding (PIF). The PIF is to be based on a determination of cost effectiveness. A PIF request must include a written analysis that addresses certain criteria found within the procedure. My request is that you issue a PIF, and this request is based on the following justification:

1. The estimated cost of construction by force account is substantially less than the estimated cost to perform the work under competitive bid.

As a basis of comparison, the VSW 1996 Solid Waste / Sewage Lagoon Upgrade Project (built using force account) was compared to DOT's 1996 Airport Erosion Protection Project (built using a contractor). The following is a comparison of the two projects, both built in Hooper Bay during the 1996 construction season:

	Solid Waste / Sewage Lagoon Upgrade Project	**Hooper Bay Airport Erosion Protection Project**
Year Built:	1996	1996
Construction Method:	Force Account	Contractor
Cost / Bid Amount:	$ 754,398	$ 806,800
Primary Accomplishment:	Installation of 59,205 cu. yd. sand embankment material (hauled 5 mi. from beach).	Installation of 23,750 sq. ft. sheet piling, 12,500 sq. ft. slope stabilization.

The cost advantages of building this project force account are as follows:

A. Mobilization and demobilization costs are drastically reduced. Since the City of Hooper Bay owns the equipment that can be utilized on the Sanitation Roads Project (discussed below under item 4), a large mobilization and demobilization of equipment is not required. The Airport Erosion Protection Project had mobilization / demobilization costs of $227,000, or 28% of the total bid. The savings to the Sanitation Roads Project is estimated at $250,000.

B. The labor costs on a force account project are less that the labor costs on a contracted project because the city is not required to pay Title 36 Laborers' and Mechanics' Minimum Rates of Pay. A comparison for this project is as follows:

Position	Force Account	Contract
Foreman	$ 16 / hr	$ 22.65 / hr
Mechanic	$ 20 / hr	$ 25.67 / hr
Truck Driver	$ 15-16 / hr	$ 24.87 / hr
Operator	$ 14-16 / hr	$ 25.67 / hr
Carpenter	$ 15 / hr	$ 25.05 / hr
Laborer	$ 12-14 / hr	$ 22.65 / hr
Housekeeper	$ 12 / hr	$ 22.65 / hr

Labor costs are roughly 40% higher on a contracted project. It is estimated that 30% of the cost of the Sanitation Roads Project will be for labor, or $990,000 (using force account rates). The estimated savings using force account labor is nearly $400,000.

C. There are no profit or overhead costs associated with a force account project as compared to a contracted project. Profit and overhead is estimated at 5% to 10% of the total cost of the Sanitation Roads Project, or a minimum of $165,000 in savings.

D. Since force account workers live in the community, the cost of a camp for the contractor's workers is not needed. The estimated savings is $150,000 including freight and camp set-up costs.

E. There is less engineering cost on a force account project because the engineer does not have to produce detailed performance specifications. There are also savings associated with eliminating the advertise/bid/award process as well as the cost of pre-bid and pre-construction conferences. The cost of designing the Hooper Bay Sanitation Roads Project is $158,883, or 4.8%, as opposed to 6% to 10% on contracted projects for a savings of $40,000.

In summary, the total estimated savings on the proposed Sanitation Roads Project is slightly more than $1 million if the project is built using force account methods as compared to contracting methods.

A cost summary from the 1996 Solid Waste / Sewage Lagoon Upgrade Project is attached. The City of Hooper Bay, using force account methods, constructed earthen dikes around the solid waste disposal site and a new sewage lagoon. The city hauled 59,205 cubic yards of material approximately 5 miles from the beach near the airport to the construction site. The cost of moving and placing this material was $12.75 per yard, including all field engineering, labor, supervision, equipment time, materials, fuel and royalty. It is estimated that the cost to move the material using a contractor would be $20.00 per yard.

2. The City of Hooper Bay has requested that it be allowed to proceed with construction of the sanitation roads project on a force account basis. A resolution passed by the Hooper Bay City Council is attached.

3. Local labor is available and willing to perform the work for the duration of the project, which is expected to last two additional construction seasons. During the 1996 construction season, a total of 30 local workers were employed on the city's Solid Waste / Sewage Lagoon Upgrade Project. The pay rates were as follows:

POSITION	RATE	EMPLOYER'S COST*
Foreman:	$ 16 / hr	$ 22.22 / hr
Mechanic:	$ 20/ hr	$ 27.78 / hr
Truck Driver:	$ 15-16 / hr	$ 20.83 - 22.22 / hr
Operator:	$ 14-16 / hr	$ 19.44 - 22.22 / hr
Carpenter:	$ 15 / hr	$ 20.83 / hr
Laborer:	$ 12-14 / hr	$ 16.67 - 19.44 / hr
Housekeeper:	$ 12 / hr	$ 16.67

* Employer's cost is based on taking the hourly rates and adjusting for a 60 hour work week (40 hours at regular time and 20 hours of overtime at time-and-one-half), then multiplying by the employer's payroll costs: Worker's Comp. (7.79%) + FICA (7.65%) + ESC (3.6%) = 19.04%.

4. The City of Hooper Bay owns equipment that is adequate to undertake the construction project and the equipment is available for the duration of the project. The following equipment is available in Hooper Bay:

3	Volvo A25 Articulated Dump Trucks (1990, 1992, 1992)
1	Cat 433 Vibratory Self-propelled Compactor (1985)
1	Cat EL200B Tracked Excavator (1990)
1	Cat D4H Dozer (1995)
1	John Deere 544 Loader (1990)
1	Honda TRX300 ATV (1996)

The City of Hooper Bay has an enclosed shop for equipment servicing and maintenance. The city maintains the equipment, which is in good working condition.

5. The impact of force account construction on the private sector in the geographical area is minimal. There are no private sector construction contractors in Hooper Bay. The nearest general contractor is based in Bethel, 156 air miles to the east of the community. There are no roads connecting Hooper Bay with any other community in Alaska.

6. The use of force account on this project is not dictated by an emergency.

VSW is currently designing the Hooper Bay Sanitation Roads Project with the assistance of a private consultant. VSW requests that you make the determination that it is in the Public's best interest to use force account materials, labor and equipment to construct the sanitation roads project.

Naparyarmiut
City of Hooper Bay
P.O Box 37
Hooper Bay, Alaska 99604
(907) 758-4311

Resolution No. 96-12-02

WHEREAS: The City of Hooper Bay is a Second-Class City in the Unorganized Borough of the State of Alaska; and

WHEREAS: The Hooper Bay City Council is the governing body of the City of Hooper Bay; and

WHEREAS: The City of Hooper Bay desires to improve the local road system within the City Limits to facilitate public health and sanitation;

NOW THEREFORE BE IT RESOLVED BY THE COMMON COUNCIL OF THE CITY OF HOOPER BAY:

That the City Council requests authority from the State of Alaska, Department of Transportation and Public Facilities to construct Hooper Bay Sanitation Roads Improvements Project on a force account basis.

Introduced at a regular meeting of the Hooper Bay City Council on December 17, 19 and passed by a vote of six yeas and no nays, a quorum being present.

Nile Smith

Nile Smith, Mayor

attest: Sharon L. Tomaganuk

Sharon Tomaganuk, City Clerk

Bulk Fuel Deficiency Rankings by Community

Community	Weighted Score	Community	Weighted Score	Community	Weighted Score
Nikolai	127.5	Kiana	67.4	Gustavus	41.7
Arctic Village	122.9	Emmonak	67.3	Port Lions	40.0
Kotlik	121.7	Deering	67.0	McGrath	39.6
Chalkyitsik	119.4	Sheldon Point	67.0	Pelican	39.5
Beaver	116.1	Lower Kalskag	66.8	Pilot Station	39.4
Venetie	115.1	Shishmaref	65.4	Napakiak	38.9
Rampart	115.0	Stony River	65.2	Levelock	37.6
Aleknagik	111.3	Telida	65.0	Aniak	37.5
Port Protection	110.0	Alakanuk	64.9	Grayling	36.5
Chignik Lagoon	108.2	Brevig Mission	64.7	Kasaan	35.0
Noorvik	107.4	Nightmute	64.3	Quinhagak	34.7
Takotna	102.9	Port Alsworth	64.0	Oscarville	34.6
Red Devil	101.3	Russian Mission	63.7	Golovin	33.8
Toksook Bay	101.1	Newtok	63.3	Koliganek	33.6
Point Baker	100.0	Shungnak	62.4	Nondalton	33.5
Diomede	99.9	Hooper Bay	62.1	Metlakatla	33.4
Larsen Bay	99.8	False Pass	61.0	Kaktovik	33.3
Birch Creek	98.6	Bettles	60.6	Galena	33.2
Old Harbor	95.6	Akiachak	60.0	Scammon Bay	32.4
Chignik Lake	94.6	Pilot Point	59.5	Saint Mary's	32.1
Atka	94.3	Coffman Cove	58.2	Teller	32.0
Kongiganak	91.1	Ouzinkie	58.1	Chignik Bay	31.7
Crooked Creek	91.0	Craig	57.5	Shaktoolik	31.4
Chevak	90.1	South Naknek	57.3	Savoonga	31.2
Tanana	84.3	Tuntutuliak	57.2	Wales	29.6
Togiak	83.7	Allakaket	57.0	Ambler	29.4
Tununak	83.2	Unalakleet	56.0	Goodnews Bay	28.7
Upper Kalskag	82.6	Kaltag	55.9	Klawock	28.5
Kokhanok	81.9	Stevens Village	55.0	Wainwright	28.3
Nulato	81.8	New Stuyahok	54.9	Hughes	26.9
Manokotak	81.5	Mekoryuk	54.9	Kwigillingok	25.0
Koyukuk	80.3	Fort Yukon	54.9	Twin Hills	24.6
Huslia	80.0	Elim	54.5	Akiak	23.5
Buckland	79.6	Pedro Bay	54.1	Kivalina	23.3
Sand Point	79.0	Nunapitchuk	53.6	Napaskiak	23.2
Gambell	78.3	Thorne Bay	53.2	Perryville	20.9
Koyuk	77.8	Kwethluk	52.2	Selawik	20.1
Chefornak	77.7	Marshall	50.3	Alatna	20.0
Clarks Point	76.4	Ivanof Bay	50.1	Hollis	20.0
Chuathbaluk	75.9	Elfin Cove	50.0	Pitka's Point	20.0
Kasigluk	74.3	Tenakee Springs	49.5	Port Alexander	17.2

Bulk Fuel Deficiency Rankings by Community

Community	Weighted Score	Community	Weighted Score	Community	Weighted Score
Egegik	74.3	Kobuk	49.5	Nuiqsut	16.7
Sleetmute	72.3	King Cove	49.1	Anaktuvuk Pass	15.8
Noatak	71.6	Iliamna	48.4	Point Lay	10.3
Anvik	71.3	Tatitlek	48.0	Point Hope	10.2
Mountain Village	70.9	Hoonah	47.4	Hydaburg	8.2
White Mountain	70.0	Saint Michael	47.0	Cold Bay	7.3
Akutan	69.6	Kipnuk	45.6	Karluk	5.0
Platinum	69.5	Kake	44.9	Naknek	3.6
Stebbins	69.1	Eek	43.9	Atqasuk	1.3
Igiugig	69.0	Holy Cross	43.0	Angoon	0.9
Newhalen	68.1	Tuluksak	42.7	Atmautluak	0.2
Port Heiden	67.7	Ruby	42.5	Lime Village	---
Shageluk	67.5	Ekwok	41.8		