2.4.4.1 Utility Cogeneration— Sale of Heat to End-Use Customers

See Figures 2-3, 2-4, and 2-5 above.

Where electricity is the primary product and heat is the byproduct, heat is priced somewhere between the incremental cost of heat production and the avoided cost of the heat customer. In the illustrative example in Figure 2-2, this means the heat byproduct can be priced between $4.00 and $14.20 per MMBtu.[12] One common approach in rural Alaska is for the electric utility to offer heat at 50 percent of the avoided fuel cost of the customer. In the illustrative example, this would amount to 50%X $1.30 ÷ (0.7 X 138,500) X 1,000,000 ≈ $6.70/MMBTU. The cogeneration system efficiency is shared roughly 2/3 with the heat customer and 1/3 with the cogeneration system heat producer.

Please note that this characterization involves a heating load that is proximate to the cogeneration heat source. As the distance between the heating load increases from the cogeneration heat production, the net losses due to pumping and heat loss increase and the capital costs of piping and insulation between heat exchangers increase. Given the sharing of cogeneration benefits profile (2/3 customer, 1/3 cogeneration system), the additional costs associated with shipping the heat across tend to be borne predominately by the customer. All other things being equal, the customer's economics favor a distribution system (capital + O&M) that will cost less than the difference between the price of heat at the source of production and the avoided cost of heating fuel. Thus, the distribution system capital and operating costs need to fit within the avoided cost of fuel for heating production of $12.52/MMBtu and the price of heat from the cogeneration source of $6.70/MMBtu in the example.[13]

These simplified examples do not explicitly take into account the wide variation in costs that may arise given variations between the electrical/cogeneration heat production load profile and the heating requirements load profile. It appears that on the order of 1/6 of the rural utilities that have a functioning heat recovery system have a metering system in place to measure these variations and allow them to be accounted for. In other words, roughly 80 percent of the utility heat recovery systems do not meter the system. They have made some "assumptions" about the rough aggregate average value of the heat and are billing or have traded something based on that rough estimate.

2.4.4.2 Facility Cogeneration – Sale of Electricity to Utility

Conversely, when heat is the primary product and electricity is the byproduct, electricity is priced somewhere between the incremental cost of electricity production and the avoided cost of the electricity customer. In the illustrative example (Figure 2), this means the electricity byproduct can be priced between $0.04/kWh and $0.13/kWh. An example of this might be a school that runs a cogeneration system to provide heat and sells the electricity byproduct that it doesn't use itself back to the electric utility (Figure 5). In many national and international markets, especially in northern climates, it is quite common to find cogeneration plants that are heat or industrial process driven that sell excess electricity back to the utility power grid at the utility's avoided cost.[14] These markets require interconnection agreements with utilities that find value in cogeneration electricity provided by customers. One report concludes that the cogeneration market for electric sales to utilities

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[12] Note well that even with a relatively small change in overall system efficiency from 54.5% to 62%, this represents a significant value opportunity – enabling a heat byproduct to be priced between roughly $4 and $14 per million BTU – assuming that the heat load is located in proximity to the cogeneration plant.

[13] This implicitly assumes that the customer will maintain a back-up diesel-fired hot water heater and perform periodic maintenance to ensure that the unit works if needed.

[14] See for example, "The Future of Combined Heat and Power in the European Market—The European Cogeneration Study,", Project No: 4.1031/P/99-169.

between 10kW and 50MW is very sensitive to incumbent utility interconnection prices, terms and conditions.[15] Those terms and conditions appear to vary according to the value that incumbent utilities place upon alternative electricity sources for their grids.

In some U.S. markets, state regulators have implemented the Public Utilities Regulatory Policy Act of 1978 (PURPA) requirements and require utilities to allow a net energy billing system whereby a single meter could be used and a qualified cogeneration facility would only pay for the net amount of electricity purchased from the utility.

In Alaska, the APUC/RCA *declined* to implement net energy billing noting that the incremental costs may favor certain qualified cogeneration facilities or general ratepayers depending upon the difference between average rates and incremental rates.[16] For electric utilities, the APUC/RCA regulations describe an avoided cost calculation that includes:[17]

- For "non-firm power," rates must be based on the cost of energy that the electric utility avoids by virtue of its interconnection with the qualifying facility. Avoided energy costs must be determined from the sum of fuel and variable operating and maintenance expenses.
- For "firm power," rates must be based on the costs of energy and capacity that the electric utility avoids by virtue of its interconnection with the qualifying facility. In determining avoided energy and capacity costs, to the extent practicable, the following factors must be taken into account:
    - Estimated avoided energy costs
    - Electric utility's plan for the addition of capacity
    - Estimated capacity costs
    - Ability of the electric utility to avoid costs due to the availability of energy or capacity from the qualifying facility
    - Costs or savings resulting from variations in line losses due solely to purchases from qualifying facilities

Thus, the question of whether avoided capacity gets included in the avoided cost becomes a debate over whether the power being provided can be classified as firm or not. The regulations define "firm power" as:[18]

> *Electric power generated by the qualifying facility…which is supplied to the electric utility in predetermined and reliable quantities at specific times and intervals, and which will enable the electric utility to reduce, defer, or eliminate planned generating units or purchases of capacity.*

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[15] Ibid, p. 7.

[16] 4 APUC 261 (1982). However, the APUC/RCA regulations, 3 AAC 50.760(h), provide that an electric utility shall offer a qualifying facility that has a generating capacity of 10 kilowatts or less the option of using a single detent metering during parallel operation. See section 3.8 of http://www.usbr.gov/power/data/fist/fist3_10/3_10_3.htm for a description of a detent (non-reversible) meter. Given the heightened interest in distributed generation and meeting the needs of customers in the late 1990s and more recently, many regulatory commissions have allowed and in some cases encouraged the availability of reversible meters.

[17] 3 AAC 50.750-820 (1982)

[18] 3 AAC 50.820 (6)

Electric utilities have argued that this regulation requires firm power to have two basic characteristics:

- Predetermined and reliable quantities at specific times and intervals

  and

- Electric utility able to reduce, defer, or eliminate planned generating units

Both of these characteristics need to be present in order for power to be classified as firm. So that even if the electric utility were able to reduce, defer, or eliminate planned generating units, if the power provided is not "predetermined", "reliable", at "specific times and intervals" it would not qualify as firm power. Thus, the question then shifts to whether a cogeneration unit can offer predetermined reliable power at specific times. Many forms of cogeneration are not designed to meet this standard. Individual cogeneration units may provide reliable power, but not necessarily at a predetermined quantity or specific time.

However, it is possible that a significant number of small household cogeneration units could effectively meet this requirement in a community due to the statistical certainty that may arise from a large number of households and knowledge of their peak heat and electrical consumption and cogeneration electrical supply potential relative to the overall electrical load.

Thus, it may be of interest to allow a rural utility to conduct a pilot project to explore the feasibility of household cogeneration.[19] Given the popularity of the small, highly efficient oil burners in rural Alaska communities throughout the State,[20] the addition of a small high-efficiency heat/electric household cogeneration unit may prove quite economical and of interest in the marketplace.

2.4.5 Customer Market Considerations

A potential market for cogeneration heat, the rural school principals, appear concerned with whether a diesel power plant will be able to provide a rural school with **reliable** heat. In addition, the **quantity** and **quality** of the heat have to be sufficient to meet the particular end-use heating requirements.[21]

Reliability

Is the utility-provided cogeneration heat sufficiently reliable for the customer to buy it at 50 percent of the avoided cost of fuel? While a 50 percent discount sounds quite attractive on its face, some schools in rural Alaska have declined to purchase heat from the local electric utility citing reliability concerns. In a typical rural Alaska installation, the cogeneration heat is designed to provide a temperature boost to the inlet side of a facility's boilers. Thus, from the point of view of the facility, the boiler and its operations and maintenance requirements are at least as much as they were previously. If the cogeneration heat source is not reliable, the operations, maintenance and troubleshooting of the facilities heating system can become a maintenance headache for the facility operator. If the heat source becomes unreliable during a time of high facility occupancy (e.g., a basketball tournament at

[19] MAFA recommends an explicit effort to obtain the support of both the community and the utility prior to funding the pilot project. Support of the electric utility is critical to enable interconnection and management of the new dynamics of the electric distribution network. Even with the support of the electric utility, this may prove an interesting and challenging pilot project in a rural Alaska environment. Without the support of the electric utility, it is unlikely to yield positive results.

[20] Based on NEI's small rural household end-use survey in 2001, interviews with Weatherization program administrators and field personnel, and high-efficiency heating unit retail sales outlets, the market for small high-efficiency direct vent "Toyo" and "Monitor" type oil-fired air heating units appears to be robust and continuing to grow in rural Alaska.

[21] Interviews with rural Alaska high school personnel, ISER OMM Field Work (2000/2001).

the local school), the facility operator and manager may perceive the potential fuel savings to be modest compared to maintaining control of their own system with a higher perceived level of reliability. This may be reinforced by an end-user's annual budget cycle where the fuel savings resulting from using cogeneration heat to displace diesel-fired boiler heating is cut from a future year's budget, reducing the "discretionary" budget of an end-use facility administrator. In short, if you spend less this year, you get less next year.

Quantity

When the peak electrical load and peak for heating load are coincident, then there may be a good potential for the electrical lead utility plant to provide sufficient heat to enable a large enough cost of heat savings to justify the "lack of control over one's own destiny" in a remote rural setting. Where the peaks are not coincident, the quantity and potential price of heat available may limit the market opportunity.

In general, the electrical load and heating load peaks in rural Alaska do appear to be coincident, suggesting a significant potential for cogeneration of electricity and heat.

Quality

The typical current heat recovery system uses a thermostatic valve and heat exchanger to isolate the system and transfer heat from the engine jacket water cooling loop to a secondary circuit piping network that carries the hot fluid to the end-use facility. Diesel fired "normal" jacket water typically falls in the 200° F range based on the manufacturer's literature. Field experience in Alaska suggests the use of 190° F to avoid overestimating the value of the heat. This temperature limits the potential market of end-use by constraining the economic distance of the end-use heat exchange from the cogeneration heat source and limiting the temperature drop and associated efficiency across the heat exchange at the end-use.

For example, a heat exchange system designed to maintain the temperature of a village piped water supply system at around 40° F, where the cogeneration heat exchange is adjacent to a heat exchanger on a main water loop, provides an efficient installation. There is minimal heat loss *and* high heat exchange transfer efficiency due to the high differential temperature. This market remains an efficient use of diesel cogeneration heat where the water utility values the margin of safety against freeze up. Another key issue is whether the local electric utility and water utility are able to provide good quality water in their heat exchange systems to prevent build-up of deposits on the inside of heat exchangers, which leads to degraded performance and high maintenance requirements.

In contrast, systems designed to provide a temperature boost to the inlet side of a facility's boilers (e.g., school installation), may be located some distance from the cogeneration heat source and may be required to maintain 180° F water at the facility's heat loop return. In addition, the efficiency of the heat exchanger process may decline due to fouling from mediocre water quality. Further, these systems may experience problems with the variation in cogeneration heat source as the electrical load changes. One potential way to increase system efficiency and enable a slightly higher level of variation tolerance in the facility is to design building heat systems for a 160° F return— typically requiring a different set of building baseboard radiators to optimize system heating efficiency than is standard. Another way to improve system efficiency is to design building heat systems for "in floor" heating systems that can be designed with 120° F return loop temperatures.

Control over One's Own Destiny

Alaska Power Company reports that systems that have been supplying reliable cogeneration heat in good quality and quantity at a good price have been discontinued by end-users.[22] The discontinuance does not appear to be directly related to price, reliability, quality or quantity, but rather appears to be due to the availability of an alternative (boiler in place) and the desire for the end-user to retain control over their own destiny.

The key parameters driving a market assessment of diesel cogeneration systems include:

- Relative efficiency of separate production vs. cogeneration
- Diesel electricity efficiency (electricity only vs. cogeneration)
- Heat recovery efficiency (heat only vs. cogeneration)
- Price of fuel (electricity, heat only, cogeneration)
- Distance of byproduct load from cogeneration plant and associated energy losses (including pumping)
- Differential temperature across heat exchangers

2.4.5.1 Specific Market Triggers

In addition to the general market conditions that favor cogeneration systems, the following may trigger market opportunities for cogenerations:

- Existing diesel(s) are at or near time for overhaul or replacement
    - New diesels with a new heat recovery system could be installed
- A significant new demand for electricity, associated with:
    - New or upgraded water/sewer facilities
    - New housing project
    - New or upgraded school
- A significant new or reconfigured demand for heat, associated with:
    - New power plant
    - New tank farm
    - New or upgraded water/sewer facilities

Thus, the best opportunities for cogeneration systems are likely to be found at the confluence of:

- **A heat customer who is open to "contracting out" a portion of their heating requirements to the local utility**
- Moderate to high cost of diesel fuel (Price of fuel plus potential cost of storage and handling requirements)
- Moderate to high operations, maintenance, and management sophistication (Including reliable information on system operations and performance typically available from SCADA systems. Without reliable systems information, troubleshooting any problems that arise

[22] Tetlin and the Alcan Border station are cited by Alaska Power Company.

becomes more difficult and often results in the "complicated" problem being solved by avoiding the complication altogether)

- A significant new demand for heat or electricity is imminent in the community

2.4.5.2 Market Intervention Program Design Considerations

The primary goal of this report is to develop *cost effective* initiatives that reduce unit costs and improve reliability of energy services for rural Alaska residents, businesses, non-profits and government agencies.

In addition, the initiatives are to be examined for how they distribute the benefits to as many communities and as many rural households as possible.

Additional considerations include the extent to which the initiatives can be designed to use private sector contracts to accomplish the specific program purpose.[23]

In the search for effective programs to implement energy infrastructure improvements in rural Alaska, the following questions may be helpful to frame the discussion:

- What happens without government assistance?
- What cost effective infrastructure should be developed to provide value to Alaskans?
- What are the barriers to cost-effective infrastructure?
- What are some alternative measures to reducing barriers to cost-effective infrastructure development?
- What are the benefits, costs and risks of those measures?
- Recommendations

2.4.5.3 Market Trends Absent New Intervention

What's happening?

From the AEA condition survey, it appears that roughly half of the diesel-fired electric power plant systems in rural Alaska utilities have some form of functioning heat recovery system. About one out of six of those are metered.

Anecdotal evidence from utility interviews suggests that even where heat customers are currently receiving service, some of them are discontinuing service when there is a change in operation (new diesel generator being installed). It is unclear why this is happening. Additional market research should be conducted to ascertain what factors can help utilities and their customers find mutually beneficial uses of the heat and electricity available from each other.

What* should be *happening?

- Power plant—warm standby, building and shop heating
- Water loop temperature maintenance
- Public facility temperature maintenance

[23] See Alaska Energy Authority Statutes.

- o Lower public facility design temperature to improve system efficiency

What are the barriers to cost effective cogeneration deployments?

Key barriers to consider include:

- o Lack of customer incentive to purchase cogeneration heat/electricity
- o Lack of customer incentive to install heating/electrical systems designed to make efficient use of cogeneration heat/electricity
- o Lack of customer operating funds to pay for cogeneration heat/electricity
- o Lack of supplier incentive to trade or sell cogeneration heat/electricity to uncertain buyer market
- o Differentials between buyer and seller perceptions about value (lack of shared information)
- o Concerns about reliability of service
- o Lack of technical information available to the potential customer of cogeneration heat regarding reliability, cost, and payback.

2.4.6 Market Intervention Program Alternatives

Basic market intervention alternatives available to the state/federal government policy makers include:

- ❖ Investment Incentives
  - o Accelerated Depreciation

    Typically, a business is allowed to depreciate the value of its assets such as equipment and other capital. This depreciation can then be deducted from the business's yearly income taxes paid to the government. Usually, this reduction is based on the acquisition value of the equipment and can only be depreciated at a certain, defined amount. However, allowing accelerated depreciation of new diesel units (for example, allowing 100 percent depreciation of a new diesel unit in the first year of operation or over the first few years) will significantly lower the amount of income taxes paid during the initial stage of the project.

    Again, since most rural Alaska communities are served by non-profits, the potential tax benefits of this approach are limited.

    However, for regulated utilities (both for-profit and non-profit), this has some attraction given historic Alaskan successes. In the 1980s, the APUC/RCA granted accelerated depreciation to enable rural telephone companies (for-profit and non-profit) to install digital switching. As a result, Alaska was the first state in the U.S. to achieve 100 percent digital switching in its local telephone networks.

    RCA could grant accelerated depreciation for new cost effective "energy efficiency" initiatives. To the extent that the RCA allows the capital investment in PCE rate determinations, a portion of the allowable deprecation expense could be paid for by the PCE program. The attractiveness of this solution may be limited since depreciation on capital that may be funded by grants has not been allowed in PCE rate determinations by the RCA.

    In contrast, the Denali Commission, ANTHC, RUBA, and others involved in bringing new sewer and water infrastructure to rural Alaska have started to include at least a portion of the depreciation expense from these grant funded projects in their rate development process.

This appears to be part of an effort to migrate utilities from a dependency upon grant funded capital toward a more sustainable funding model where an increasing portion of capital is funded by the local community.

Finally, even if the new cogeneration diesel units are funded by loans or private capital, the RCA may be reluctant to provide accelerated depreciation in light of the relatively high potential for free riders—these investments in infrastructure appear likely to have been made whether or not an accelerated depreciation allowance program is offered.

- Grants

  Direct cash payments might be a very efficient way to promote cost-effective diesel efficiency investments. Many times, a direct cash payment for the installation of new infrastructure is more beneficial to a potential developer who has a limited revenue base. This type of incentive also helps both taxable and non-taxable entities (such as a municipal or state-owned utility). In addition, grants add an extra benefit to a private investor by reducing the tax burden since the granted portion of the power plant usually is not taxed. On the other hand, the RCA typically treats grants as "contributed capital" to the utility and does not allow depreciation or a return on these investments (see also accelerated depreciation discussion above) in rate making.

  In the 107th Congress, S. 517 contains provisions to provide $100 million per year for FY2003-FY2009 for housing, energy, water, wastewater, bulk fuel, telecommunications and utility services. The Department of Energy is designated to distribute to communities with populations less than 10,000 and electricity prices in excess of 150 percent of the national average.[24]

  In addition, there are provisions for $20 million per year for FY2003-FY2009 for increasing energy efficiency, lowering or stabilizing electric rates to end users, or providing or modernizing electric facilities in rural and remote communities.[25]

  Finally, there are provisions for $100 million per year for FY2003-FY2009 for comprehensive rural development planning, affordable housing, and wastewater, water, telecommunications and other infrastructure needs determined to be critical to the further development or improvement of a designated industrial park.[26] This money is to be distributed to rural recovery areas where population out-migration is 1 percent or more over the previous 5 years, per capita income is less than that of the national non-metropolitan average, and the area does not include a city with a population of more than 15,000.

  The administration of grant programs could be efficiency delegated to the Denali Commission given the grant administration infrastructure in place.

  The key to cost-effective use of grant funds is to identify market opportunities where grant funds can be used to develop cost-effective efficiency alternatives that would not otherwise be accomplished with existing capital markets.

[24] SA 2996, Subtitle A: Rural and Remote Community Development Block Grants

[25] SA 2996, Subtitle B: Rural and Remote Community Electrification Grants

[26] SA 2996, Subtitle C: Rural Recovery Community Development Block Grants. The phrase "designated industrial park" is not defined in SA 2996.

In the cogeneration markets in rural Alaskan communities, some of these potential complementary uses of grant funds may include:

- o "Help seal the deal" micrograntsfor the school market.
- o Cogeneration heat source template agreements based on best practices for the water utility market
- o Design guidelines for school heating systems
- o Funding for household micro-cogeneration demonstration project

2.4.7 Reconnaissance Study

2.4.7.1 Introduction

A market reconnaissance-level analysis of cogeneration economic feasibility was conducted for this report to provide an estimate of the potential benefits and costs associated with cogeneration in the rural Alaska energy market. The analysis and underlying assumptions were developed based on the following:

- o Interviews with utility personnel
- o Feasibility studies of numerous cogeneration installations
- o Development and application of an economic model comparing cogeneration alternatives
- o Sensitivity analysis of model
- o Identification of key market failures which prevent or impede cogeneration development relative to socially optimal economic investment, defined here as B/C>1.0, 15 years, 5 percent real discount rate.

2.4.7.2 Analysis of Reconnaissance Study Results

The key drivers of utility cogeneration of heat for sale to utilities and public facilities (schools) are the price of fuel and the amount of heat that can *effectively* be displaced by the diesel cogeneration plant (function of total heat output of cogeneration plant and match between diesel cogeneration heat production and heat demand of end-user).

The big three parameters that drive the economics of cogeneration include:

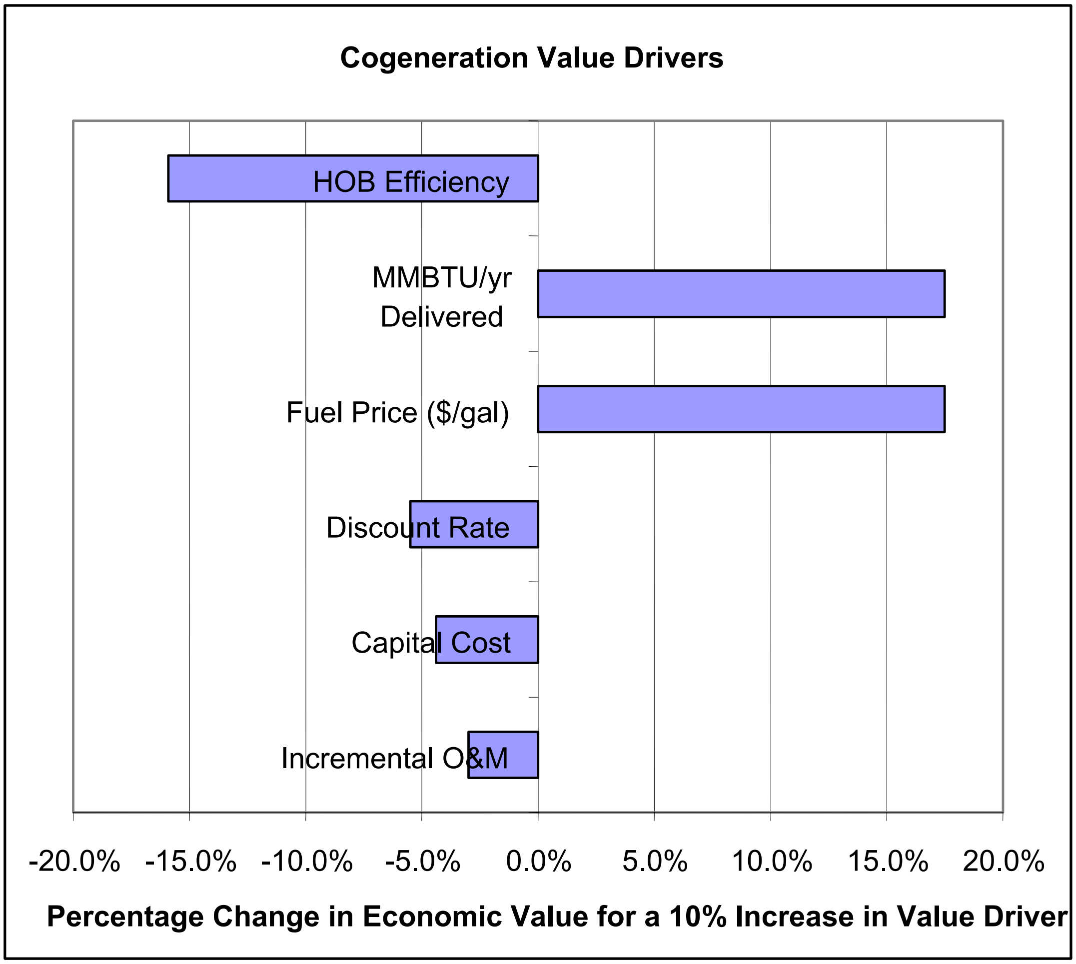
- ❑ The price of diesel fuel (utility and heat customer)
- ❑ The efficiency of the cogeneration heat system
- ❑ The efficiency of the customer's heating system ("heating oil boiler efficiency, abbreviated below as "HOB Efficiency")

A value driver analysis is provided in Figure 2-6 on the following page.

Figure 2-6. Cogeneration Value Drivers

A 10% in this parameter drives an X% change in NPV

Incremental O&M	-3.0%
Capital Cost	-4.4%
Discount Rate	-5.5%
Fuel Price ($/gal)	17.5%
MMBTU/yr Delivered	17.5%
HOB Efficiency	-15.9%



Source: MAFA, 2002

2.4.8 Description of Diesel Cogeneration Technologies

2.4.8.1 Background

Diesel Cogeneration Production Market Segments

Commercial/Small Utility	~100kW – ~2000kW
Small Commercial (a.k.a. mini)	15-100kW
Domestic	<15kW
Micro	~3kW and below

2.4.8.2 Commercial/Small Utility Diesel Electric Power Plant

Internal combustion engines produce heat as a by-product of combustion. Roughly 30 percent of fuel energy required for engine operation results in heat rejected to the jacket water, and must be totally removed by the engine's cooling system to assure dependable engine performance.

The cooling system is comprised of the jacket water circuit and depending upon engine configuration, aftercooler, oil cooler, and fuel cooler circuits.

A small percentage of heat is also rejected to the atmosphere and is removed by engine room ventilation.

The distribution of input fuel to energy is approximately:

- 33 percent to useful work (producing ~13.5 kWh per gallon)
- 30 percent to rejected work
- 30 percent to jacket water
- 7 percent to friction and radiation

Heat recovery design for any installation depends upon several technical and economic considerations. The primary function of any heat recovery system is to cool an engine or group of engines. Provisions must be made to ensure engines operate at correct temperatures, even when plant demands are small.

Fuel is the largest operating expense associated with a diesel generator set. In typical prime power applications, fuel costs over a 15-year cycle can range from 75 to 85 percent of total life cycle costs. In installations where heat can be recovered and used, it is possible to increase total energy output per dollar significantly.

Standard temperature heat recovery uses a shell and tube heat exchanger to transfer the heat of normal jacket water (usually around 190 – 200° F) to a secondary circuit – usually water.

The typical heat recovery system involving standard temperature jacket water includes standard engine equipment. Plant hot water is taken from the secondary side of the heat exchanger. After warmup, the regulator opens flow to the plant load heat exchanger.

Ideally all flow passes through an expansion tank to promote deaeration. The added external head of the extended jacket water circuit may exceed the allowable head on the engine mounted pump, so an auxiliary pump may be necessary.

The amount of heat available is dependent upon the mechanical load on the engine. In times when the electrical loads are light but plant heat loads are high, an additional heating source, (e.g., a boiler), may be necessary. If heating loads are sometimes low when electrical loads are high, a load balancing heat exchanger (a.k.a. radiator) may be required.

2.4.8.3 Domestic/Micro Cogeneration

Diesel is consumed in a Stirling engine or other prime mover to provide heat and electricity for use within a home.

The distribution of input fuel to energy is approximately:

- 70 percent to heat (hot water for space heating and domestic hot water)
- 20 percent to electricity
- 10 percent lost in flue gases

This compares to conventional boilers where roughly 75 percent of the energy is converted into heat and 25 percent is lost in the flue gases.

The electricity generated in the home is quite valuable where the incremental cost of electricity may range from 12 to 50 cents per kWh.

Typical break-even analysis assumes that the new micro-cogeneration units will be installed in homes to replace existing boilers that have reached the end of their useful life. The household is then faced with a choice of installing a new boiler or a micro-cogeneration unit. The micro cogeneration units sized at around 3kW appear to be roughly $2,000 more expensive than a standard boiler.

Micro-cogeneration is thermally led. The unit operates when there is a demand for heat, and electricity is the byproduct.

During the winter day in rural Alaska, this may provide an electric utility with an opportunity to buy "excess electricity" from households and reduce the amount of electricity that is needed to meet the winter peak day requirements.

During the winter night in rural Alaska, this would tend to result in an excess of electricity being available during the "graveyard" shift (midnight to 7am). If a utility were able to buy the "excess electricity" from households and store it for the morning ramp up in electrical load, it could improve reliability and reduce the need for having as much warm standby available in the power plant if it were available in a stored form at the power plant.

2.5 Appendix

Combined Heat & Power

Simplified Example

Capacity (kW)	250									
NPV =	$85,673	$49,626	$27,968	$0	$57,495	$160,562	$235,451	$48,228	$107,070	$0
Discount Rate	5%	10%	15%							15%
Capital Cost	$40,000			$129,956						$42,178
Incremental O&M	$2,400				$5,000					$5,000
Fuel Price ($/gal)	$1.00					$1.50	$2.00			$1.15
MMBTU/yr Delivered	1600							1200		1200
HOB Efficiency	80%								70%	80%
BTU/gallon (LHV)	132000									
Gallons/displaced	15,152									
Annual Savings	$15,152									

		2002	2003	2004	2005	2006	2007	2008	2009	2010
Capital		($40,000)								
O&M		($2,400)	($2,400)	($2,400)	($2,400)	($2,400)	($2,400)	($2,400)	($2,400)	($2,400)
Fuel Savings			$15,152	$15,152	$15,152	$15,152	$15,152	$15,152	$15,152	$15,152
Total Cash Flow		($42,400)	$12,752	$12,752	$12,752	$12,752	$12,752	$12,752	$12,752	$12,752
Net Present Value	5%	**$85,673**								
IRR	29%									

(15 year life)

Combined Heat & Power

Simplified Example

Capacity (kW) 250

Heat Fuel Tanks & Lines to Enable Use of No. 2 rather than No. 1 Blend

NPV =	$17,048	$1,625	$0	($7,330)	$0
Discount Rate	5%	10%	10%	15%	5%
Capital Cost	$40,000				
Incremental O&M	$2,400				
Fuel Price ($/gal)	$1.00				
Fuel Price Differential	10.0%		9.7%		7.9%
Gallons per year	82,095				

		2002	2003	2004	2005
Capital		($40,000)			
O&M		($2,400)	($2,400)	($2,400)	($2,400)
Fuel Savings			$8,210	$8,210	$8,210
Total Cash Flow		($42,400)	$5,810	$5,810	$5,810
Net Present Value	5%	**$17,048**			
IRR	11%				

(15 year life)