**ADVANCED COGENERATION AND ABSORPTION CHILLERS
POTENTIAL FOR SERVICE TO NAVY BASES**

FINAL REPORT

**J. W. Andrews, T. A. Butcher, R. W. Leigh
R. J. McDonald, and B. L. Pierce**

April 1996

**Prepared for:
Strategic Environmental Research and Development Program
Office of the Director of Defense Research and Engineering
U.S. Department of Defense
Washington, DC 20301-3030**

MASTER

**Energy Efficiency and
Conservation Division**

DEPARTMENT OF APPLIED SCIENCE

**BROOKHAVEN NATIONAL LABORATORY
UPTON, LONG ISLAND, NEW YORK 11973**

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED *kg*

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, nor any of their contractors, subcontractors, or their employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency, contractor, or subcontractor thereof.

**ADVANCED COGENERATION AND ABSORPTION CHILLERS
POTENTIAL FOR SERVICE TO NAVY BASES**

FINAL REPORT

BY:

**J. W. Andrews, T. A. Butcher, R. W. Leigh
R. J. McDonald, and B. L. Pierce**

APRIL 1996

**Prepared for:
Strategic Environmental Research and Development Program
Office of the Director of Defense Research and Engineering
U.S. Department of Defense
Washington, DC 20301-3030**

Under Contract No. DE-AC02-76CH00016

**Brookhaven National Laboratory
Upton, NY 11973**

TABLE OF CONTENTS

1	SUMMARY AND CONCLUSIONS	1-1
1.1	Introduction	1-1
1.2	The Reasons for Distributed Cogeneration	1-1
1.3	Summary of Study Results	1-2
1.4	Conclusions	1-5
2	SMALL SCALE COGENERATION TECHNOLOGY	2-1
2.1	Currently Available Technology	2-1
2.2	Technical Problem Area: Reliability	2-3
2.3	Near-Term New Technology	2-4
2.4	Competing Technology Options	2-8
2.5	Environmental Regulations	2-9
2.6	Options for Reducing Emissions in Engine Exhaust	2-17
3	COMPATIBLE ABSORPTION TECHNOLOGY	3-1
3.1	Currently Available Technology	3-1
3.2	Potential Technology Advances	3-4
4	MODEL FACILITY DEFINITION AND SIMULATION	4-1
4.1	Introduction	4-1
4.2	Description of Site	4-1
4.3	Energy Use Intensities	4-1
4.4	Cogenerators and Chillers	4-3

TABLE OF CONTENTS (Cont.)

4.5	Site Characterization in Terms of Energy Inputs	4-4
4.6	Electric Load Duration Curve	4-4
4.7	Heating and Cooling Load Curves	4-6
4.8	Optimal Installation for a Large Building	4-6
4.9	Heating and Cooling the Buildings	4-8
4.10	Control Strategy	4-9
4.11	Spreadsheet Analysis of System Operation	4-9
4.12	District Heating Cogeneration System	4-11
4.13	Base Case Results	4-12
4.14	Primary Energy Comparisons	4-13
4.15	Demand Calculations	4-13
4.16	Comparative Emissions of Pollutants	4-18
5	COMPARATIVE ECONOMIC ANALYSIS FOR THE MODEL FACILITY .	5-1
5.1	Introduction	5-1
5.2	Economic Assumptions	5-1
5.3	Equipment Costs	5-2
5.4	Analysis for Boilers and Utility Electricity	5-5
5.5	Analysis for Modular Cogeneration	5-6
5.6	Analysis for District Heating and Cooling System	5-9

TABLE OF CONTENTS (Cont.)

6	MODULAR COGENERATION IN THE NAVY	6-1
6.1	Introduction	6-1
6.2	Annual Summaries	6-2
6.3	Seasonal Breakdowns	6-11
6.4	Loads in the Typical Multibuilding Facility	6-28
6.5	Spreadsheet Input Data	6-35
6.6	Results of Simulations	6-36
6.7	Demand Calculations for Navy EFD's	6-37
7	ECONOMICS OF MODULAR COGENERATION IN THE NAVY	7-1
7.1	Introduction	7-1
7.2	CHESDIV/LANTDIV	7-1
7.3	NORTHDIV	7-2
7.4	SOUTHDIV	7-3
7.5	WESTDI	7-3
7.6	SWESTDIV	7-4
7.7	Conclusions	7-4
	REFERENCES	R-1
	APPENDIX A - Cogeneration Simulation Spreadsheets for Model Facility with National Average Energy Loads	A-1
	APPENDIX B - Cogeneration Simulation Spreadsheets for Model Facility with Navy-EFD - Specific Energy Loads	B-1

TABLE OF CONTENTS (Cont.)

APPENDIX C - Test of MCC 85 Kw Cogenerator	C-1
APPENDIX D - Cogenerating Fuel Cells	D-1

LIST OF TABLES

1-1	Costs of Cogenerated Thermal Energy (1992 \$)	1-2
1-2	Electricity-to-Fuel Price Ratios and Payback Times for Modular Cogeneration	1-5
2-1	Available Small Cogeneration Systems	2-2
2-2	Duel Fuel Engine Characteristics	2-7
2-3	Environmental Acronyms	2-9
2-4	NAAQS Compliance Ratios	2-12
2-5	Emission Levels for Which BACT is Required	2-14
2-6	Emissions from Alternative Reciprocating Engines	2-18
3-1	Current Absorption Chiller Manufacturers	3-2
4-1	Annual Heating, Cooling, and Non-AC Electrical Loads and Energy Intensities for U.S. Commercial Buildings, 1992	4-3
4-2	Annual and Average Hourly Loads for Space/Water Heating, Space Cooling, and Electric Power Not Used for Space Cooling	4-4
4-3	Annual Energy Quantities for the Model Facility for Various Numbers of Chillers for Each Cogenerator and for the Use of District Heating and Cooling	4-14
4-4	Development of Peak Thermal and Electrical Demands for the Model Facility	4-17
4-5	Emission Factors Used in Comparing Total Amounts of Pollution Produced by Three Scenarios	4-18
4-6	Comparisons of Total Amount of Pollutant Emissions with Three Selected Scenarios	4-19
4-7	Comparison of Total Amount of On-Site Emissions with Three Selected Scenarios	4-19

LIST OF TABLES (Cont.)

5-1	Economic Assumptions for Model Facility	5-2
5-2	Equipment Costs	5-3
5-3	Boilers and Utility Electricity	5-5
5-4	Modular Cogen, No Absorption Chillers	5-6
5-5	Economic Performance Versus Number of Cogenerators	5-7
5-6	Modular Cogen with One Absorption Chiller	5-8
5-7	Modular Cogen with Two Absorption Chillers	5-9
5-8	District Heating and Cooling System	5-10
6-2-1 - 6-2-7	Summaries of Navy Data	6-4
6-3-1 - 6-3-7a	Quarterly Breakdowns of Electricity and Fuel Use and Extractions of Heating and Cooling Loads	6-12
6-4-1 - 6-4-6	Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facilities	6-29
6-5-1 - 6-5-6	Annual Energy Quantities for the Typical Multibuilding Facilities	6-38
7-1	Electricity to Fuel Price Ratios, Thermal Energy Use and Payback Time for Modular Cogeneration	7-5

LIST OF FIGURES

3-1	Performance of Yazaki 10 Ton Chillers	3-4
4-1	Electric Load-Duration Curve Used in Analysis	4-5
4-2	Yearly Plot of Thermal Inputs Needed to Heat and Cool One Large Building. Months 1-5, Heating Load. Months 7-11, Thermal Input Needed to Meet Load with Absorption Chillers	4-7
7-1	Equipment, Economic Assumptions and Baseline System Costs for CHESDIV/LANTDIV	7-6
7-2	Economics of Modular Cogeneration, With No Process Heat, for CHESDIV/LANTDIV	7-7
7-3	Economics of Modular Cogeneration, With 20% Process Heat, for CHESDIV/LANTDIV	7-8
7-4	Equipment, Economic Assumptions and Baseline System Costs for NORTHDIV	7-9
7-5	Economics of Modular Cogeneration, With No Process Heat, for NORTHDIV	7-10
7-6	Economics of Modular Cogeneration, With 20% Process Heat, for NORTHDIV	7-11
7-7	Equipment, Economics Assumptions and Baseline System Costs for SOUTHDIV	7-12
7-8	Economics of Modular Cogeneration, With No Process Heat, for SOUTHDIV	7-13
7-9	Economics of Modular Cogeneration, With Process Heat, for SOUTHDIV	7-14
7-10	Economics of Modular Cogeneration, Two Absorption Chillers Per Cogen, for SOUTHDIV	7-15

LIST OF FIGURES (Cont.)

7-11	Equipment, Economic Assumptions and Baseline System Costs for WESTDIV	7-16
7-12	Economics of Modular Cogeneration, With No Process Heat, for WESTDIV	7-17
7-13	Economics of Modular Cogeneration, With 20% Process Heat, for WESTDIV	7-18
7-14	Equipment, Economic Assumptions and Baseline System Costs for SWESTDIV	7-19
7-15	Economics of Modular Cogeneration, With No Process Heat, for SWESTDIV	7-20
7-16	Economics of Modular Cogeneration, With 20% Process Heat, for SWESTDIV	7-21

Acknowledgement:

We would like to thank Dr. Suresh Garg of the Naval Facilities Engineering Service Center and his staff for giving us access to their data base of Navy energy facilities and for helping us to make use of it.

1 SUMMARY AND CONCLUSIONS

1.1 Introduction

The U.S. military uses millions of Btu's of thermal energy to heat, cool and deliver process thermal energy to buildings on military bases, much of which is transmitted through a pipeline system incorporating thousands of miles of pipe. Much of this pipeline system is in disrepair and is nearing the end of its useful life, and the boilers which supply it are old and often inefficient. In 1993, Brookhaven National Laboratory (BNL) proposed to SERDP a three-year effort to develop advanced systems of coupled diesel cogenerators and absorption chillers which would be particularly useful in providing a continuation of the services now provided by increasingly antiquated district systems.

SERDP indicated interest in BNL's proposal by funding a much smaller, one-year effort in which BNL was to prepare a detailed work plan for the succeeding years and explain the contributions and experience of our proposed industrial partner, Modular Cogeneration Corporation (MCC) of New Rochelle, NY. Funding for the program planning effort was received at BNL in December, 1994, and work was begun immediately, based on the previously filed SERDP Execution Plan.

In mid-February, 1995, BNL learned that all subsequent funding for our program had been canceled, due to the massive decreases in overall SERDP funding and the resulting planned elimination of the Energy Conservation Technology Thrust Area. BNL staff continued to develop the Program Plan and to adhere to the requirements of the Execution Plan, but began to look for ways in which the work could be made relevant to Navy and DoD energy needs even without the extensive development plan formerly envisioned.

The entire program was therefore re-oriented to look for ways in which small scale cogeneration and absorption chilling technologies, available through procurement rather than development, could provide some solutions to the problem of deteriorated district heating systems. The result is, we believe, a striking new approach to the provision of building services on military bases: in many cases, serious study should be made of the possibility that the old district heating system should be removed or abandoned, and small-scale cogenerators and absorption chillers should be installed in each building. In the remainder of this Summary, we develop the rationale behind this concept and summarize our findings concerning the conditions under which this course of action would be advisable and the economic benefits which will accrue if it is followed. The details are developed in the succeeding sections of the report.

1.2 The Reasons for Distributed Cogeneration

"Cogeneration" refers to the simultaneous use of both heat and electric power from the same prime mover. Because the production of electrical energy from thermal sources such as fuels is at best 30 to 45% efficient, substantial amounts of thermal energy are left over when electricity is

produced by traditional means. If this thermal energy can be put to good use, the over-all efficiency of fuel utilization can be very high - up to 90 or 95%, with parallel positive impacts on thermal pollution and atmospheric emissions. Cogeneration has been employed in various applications in all parts of the world over the last one hundred years, and is often a cost-effective and worthwhile concept today.

However, the thermal energy recovered with cogeneration systems is not "free" in most cases, although the cost will vary with the nature of the prime mover. Essentially, thermal energy diverted at useful temperatures usually results in lower efficiency of electricity production, and when this and any incremental capital costs are accounted for, one finds the costs of cogenerated thermal energy indicated in Table 1-1 (from Ref. 7 of Chapter 5). Clearly the low costs associated with Diesel engines look very attractive; they occur because the extraction of heat at up to 220°F (105°C) has no effect on generation efficiency and heat exchange requirements are minimal; for this and other reasons, we will focus on these systems in this study.

	\$/MBtu
Condensing Turbine (Extraction):	4.60-5.30
Back Pressure Turbine	3.00-4.00
Combustion Turbine:	0.50-1.00
Diesel Engine:	0.10-0.30

Table 1-1: Costs of Cogenerated Thermal Energy (1992 \$).

Cogeneration systems come in all sizes, from less than 100 kW to industrial systems of many megawatts. We focus on systems at the small end of the scale, with thermal outputs comparable to the demands of single buildings for heating and cooling, so that it will not be necessary to transport thermal energy between buildings. The reason for this is straightforward: it is quite expensive to transport thermal energy between buildings in insulated pipe networks. In Section 5-3 below we show that inter-building delivery costs for hot water run from \$2.60-7.00/MBtu (million Btu's) delivered, and that the additional cost to add a chilled water capability is more than twice this. Since for diesel engines economies of scale are not large (see Section 5.3), it would seem reasonable to look at the option of eliminating the piping and distributing smaller cogenerators in each building, and that is what we do in this study.

We assume that all buildings are connected by an adequate intermediate-voltage electric distribution system, so the electric energy produced by the cogenerators can be easily shared around the facility and exported to the local utility if there is a surplus. The technology to assure this is mature; institutional relations with the local utility must be worked out individually.

1.3 Summary of Study Results

The major portion of the report, contained in Chapters 4 through 7, is a technical and economic analysis of the potential for modular cogeneration and absorption chilling to meet the

energy needs of military facilities comprising groups of buildings and their associated activities. The approach to this analysis can be summarized as follows, broken into two parts.

Part I, (Chapters 4 and 5) performed the following steps to develop methodological tools and an object for analysis:

- Develop a model of a multi building facility that can be considered sufficiently representative to use as a test article in an energy-flow model.
- Develop a methodology for assessing the energy uses of this facility over the course of a year, for various choices of energy-production means.
- Establish national-average values of energy-use requirements for commercial buildings, using Department of Energy data.
- Calculate the amounts of purchased energy (electricity and fuel) used annually by the facility, for various choices of cogenerating and non-cogenerating energy delivery systems.
- Perform an economic analysis of these options under national-average assumptions concerning fuel and electricity prices.

At this point we had a typical facility and a methodology for analyzing various energy-delivery systems, and we also had a preliminary set of results based on national-average values for energy usages and prices. What we lacked was a way to relate this to military facilities in a way that would be sufficiently region-specific to be useful. It seemed quite possible that military energy-use patterns might differ significantly from those in the civilian sector, and it seemed obvious that the value of absorption chillers would differ greatly between hot and cool climates.

We were fortunate to have been given access to a database of energy use maintained by the Navy. Although this database did not provide some details we would have liked, such as heating and cooling loads, it did give aggregated electricity- and fuel-use data for seven geographic regions on a monthly and quarterly basis. We developed a method of estimating heating and cooling loads, using the seasonal fluctuations in fuel and electricity use, and found that the results gave intuitively reasonable results that agreed, at least on an order-of-magnitude basis, with the national-average data from DOE. Having thus prepared the necessary inputs, we proceeded to analyze the Navy's data.

Part II (Chapters 6 and 7) therefore performed the following steps:

- Prepare regional summaries of the Navy data in a form useful to the analysis.
- Develop seasonal breakdowns of fuel and electricity use, and from these obtain the heating and cooling loads. Check the results for reasonableness.

- Apply these loads, for each geographic region, to the “typical multi building facility” that was characterized in Part I.
- Obtain the annual fuel and purchased electricity inputs needed by this facility, by region, for each choice of cogenerating and non-cogenerating energy delivery system.
- Assess the annual costs of operating each candidate system in each region, incorporating initial investment, energy and demand charges for purchased electricity, purchased fuel costs, and operation and maintenance costs.
- Evaluate the results for significance to the Navy. Characterize the potential for modular cogeneration with and without absorption chilling in each region.

The significance of the results for the Navy is discussed at the end of Chapter 7, and is briefly summarized here. We analyzed six regions (combining two of the Navy’s regions that overlapped geographically). One of these, covering the Pacific Islands and Japan, was dropped from further analysis because of the great diversity of climates within the region and especially because natural gas appears not to be available at most sites. Of the remaining five regions, two showed good economic potential for modular cogeneration, although absorption chillers at current prices were marginal. Two regions gave very disappointing results. The fifth region gave intermediate results.

The results were strongly driven by one factor in particular: the ratio of the price paid by the Navy for a unit of electricity to what it paid for a unit of gas. Where electricity was expensive and gas was cheap, cogeneration looked good. Where the reverse was true, it looked terrible. Table 1 shows the relevant values for the five Navy divisions studied. The fuel price ratio used the average cost for electricity per kWh, including demand and energy charges and the average price paid for natural gas, in dollars per MBtu (divided by 293 kWh/MBtu to represent both energy sources in the same units). The value of cogeneration is represented by the inverse of the payback time for the most attractive number of absorption chillers (which as it turns out was usually zero--see below).

The electricity-to-gas price ratio and the inverse payback time are highly correlated, with $r=0.86$ and $r^2=0.75$. This means that three-fourths of the variation in results among regions is associated with differences in this ratio.

The next most important variable may be the fraction of cogenerated heat that can be utilized, as detailed in Section 7.7. Of the two divisions that gave attractive results, NORTHDIV achieved a 2.8-year payback with a fuel price ratio of about 8, while WESTDIV had a slightly longer payback (3.3 years) despite a fuel price ratio that was 40% higher. The difference is probably due to the fact that in NORTHDIV, with its high heating loads, 56% of the cogenerated heat was utilized, while in WESTDIV only 29% of the heat was used.

The conclusion is to look for situations where electricity is expensive, gas is cheap, and where you have a need for significant amounts of heat at temperatures that cogenerators can provide.

Quantity: Division	Electricity-to-Gas Price Ratio	H_{used}/H_{cogen}	Payback Time (years)	Inverse Payback (1/years)
CHESDIV/ LANTDIV	3.6	47%	176	0.01
NORTHDIV	8.0	56%	2.8	0.36
SOUTHDIV	4.7	41%	42	0.02
WESTDIV	11.3	29%	3.3	0.30
SWESTDIV	5.7	22%	8.3	0.12

Note: Division names are Navy acronyms. For the most part, their geography is as follows: CHESDIV and LANTDIV cover Maryland, DC, and Virginia and activities in the North Atlantic; NORTHDIV covers New England, the Middle Atlantic, and the Midwest; SOUTHDIV covers the Southeast as far west as Texas; WESTDIV covers northern California and the Pacific Northwest; and SWESTDIV covers southern California

Table 1-2: Electricity-to-fuel price ratios and payback times for modular cogeneration.

The second salient result is that absorption chillers did not significantly improve the economics, even in SOUTHDIV where cooling loads were high. Although we were disappointed by this result, we were really not surprised. Our initial proposal to SERDP was based on the belief that the costs for absorption chillers were generally higher than could be justified by economics alone. As discussed in Section 5.5, even price reductions which could perhaps be achieved through hard bargaining over large orders might be sufficient to make absorption chillers far more attractive economically. Given their environmental benefits and low maintenance requirements, this is a proposition that should be studied closely. Development money could also be directed at lowering first costs.

1.4 Conclusions

-- The Navy should examine NORTHDIV for situations where modular cogeneration looks promising. The site should then be used in a detailed engineering assessment along the lines outlined in this report, comparing modular cogeneration, centralized cogeneration with district heating and cooling and standard boilers with utility electricity. If modular cogeneration appears preferable on the basis of the engineering study, it should be tried on a pilot basis. After assessment of the results, the Navy could replicate the tested system, modify it, or abandon the concept.

-- If the NORTHDIV engineering assessment appears positive, WESTDIV should be examined for sites where a modular cogeneration system might prove viable. If one is found, another

engineering assessment should be undertaken, with special attention paid to what prices for absorption chillers would be required to meet Navy requirements for return on investment or payback. Negotiations with Yazaki or other suppliers should then be undertaken.

-- Component cost reductions which would lead to wider use of energy-efficient technologies are possible through technical development in all aspects of modular and centralized cogeneration: heat exchanger development, controls, reliability enhancement and thermal distribution. Given the size of the armed forces infrastructure, modest funding of such technical developments could reap dramatic rewards in the three to ten year time frame.

2. SMALL SCALE COGENERATION TECHNOLOGY

2.1 Currently Available Technology

Production of small (less than 100 kW) cogeneration systems has collapsed in the United States. Only a few years ago, staff at the Gas Research Institute could confidently predict that prices on small cogeneration systems would fall and sales increase¹, while a study done at the Naval Civil Engineering Laboratory² listed twelve vendors of systems in the 100 kW and under range. Today, sales are low and not well documented, and eleven of those listed firms have either disappeared, discontinued cogeneration activities, discontinued the small end of their line or have otherwise left the field. One from that list remains, albeit with a name change, to Tecogen. In this section we examine remaining suppliers and their products and the recognized problems with their products to find the reasons for this collapse; there is no doubt that cogeneration could be efficient and environmentally desirable and it should be cost-effective and popular.

Initially, of course, we were aware of the "Smart-1" produced by our industrial partner in this project, Modular Cogeneration Corp ("MCC"). We also searched the Thomas Register³ for companies claiming a capability in reciprocating engine cogeneration. After eliminating some on the basis of size or other unsuitability, we sent an information request to each of them. The result was one positive response (from Tecogen); others either did not respond or indicated that they only produced much larger units or were no longer in cogeneration. We also established contacts with the local distributor for ISI, Inc. We attempted to contact the firms listed in the 1987 Naval Civil Engineering Study², with the results reported above. Professional contacts led to several other information requests. Perennial Energy, Inc. ("PEI") was typical of several firms that will build cogeneration sets to order; none of the others we contacted, however, were actively marketing for these jobs at this time.

The results are summarized in Table 2-1. Various physical characteristics are displayed for each machine where available. Economic parameters are to the right, the most important being the capital cost.* From these, a total cost for produced electricity is estimated. This is calculated by adding all capital and variable costs together[#] and subtracting a credit for thermal energy, approximated conservatively as one-half the unit energy cost of gas. The table shows clearly that high electric efficiency and adiabatic design result in substantially lower unit energy costs. The ISI 120 kW unit is, like the Smart-1, based on a heavy-duty industrial diesel block. Running on pure natural gas, it is supercharged with an intercooler. The remaining units are all derived from automotive Otto-cycle engines, and are restricted to lower internal pressures and efficiencies. More detailed economic analyses will be carried out in later sections.

* The "Capital Costs" shaded in grey are estimates obtained by using the highest cost per kilowatt among the known (white) values, omitting the 43kW unit.

#. The lifetimes are short, so future expenditures and savings were not discounted, and the capital component of total cost is the capital cost divided by the product of electric capacity and engine life.

Maker	Electric Output		Thermal Output			Fuel Consumption		Total	Engine	Capital	Rebld	O&M Cost		Total Cost
	Cap.	Effic.	Heat @	Temp.	Return	Gas(1)	Oil(2)	Effic.		Cost	Life	Var.	Fixed	
	(kW)		mBtu/hr	oF	@ oF	SCF/hr	gal/hr			\$(k)	k-hrs	c/kWh	k\$/yr	c/kWh
MCC	85	40%	384	205	181	569	1.0	94%	Fiat	66	20	2	0	8.1
ISI	120	38%	562	200	149	1049	0.0	91%	J. Deere	105	20	0	14	9.7
Tecogen	75	29%	470	230	187	863	0.0	82%	GM	47	20	2	0	10.7
PEI	72	30%	468	200	169	812	0.0	86%	Ford 460	51	20	2	0	11.0
PEI	100	31%	653	200	171	1093	0.0	89%	Wauk.	78	20	2	0	11.2
Tecogen	60	26%	440	230	186	760	0.0	83%	GM	42	20	2	0	11.7
PEI	43	26%	280	200	172	550	0.0	76%	Ford 300	44	20	2	0	13.3
ISI	60	26%	505	200	169	775	0.0	90%	Ford	52	20	0	14	13.3
ISI	35	29%	259	200	181	411	0.0	90%	Ford	27	20	0	14	14.2
1) Gas high heat value = 1020 Btu/SCF, cost = \$4.88 /mSCF														
2) Oil high heat value = 138 mBtu/gal, cost = \$1.00 /gal														

Table 2-1: Available Small Cogeneration Systems.

2.2 Technical Problem Area: Reliability

Despite the promising economics outlined in the last section, small cogeneration sets have enjoyed only modest growth. Most technical characteristics of cogenerators, such as efficiency, fuel utilization, power conditioning and so forth all seem either adequate to the task or better than adequate. (Fuel utilization is clearly better than that with any other means of providing electric energy and heat.) The problem can perhaps be summed up by asserting that for equipment in this size range, which must get by with very little individual maintenance, managers and decision makers seem to demand reliability and performance similar to a furnace, rather than characteristics which might be found in an automobile or truck. This is unfortunate, since cogeneration sets are similar to vehicles in their complexity. Reliability is therefore the primary technical problem area for small cogenerators.

There are two complementary paths to sufficiently reliable systems. The first, reviewed immediately below, is to make each individual machine as reliable as possible. The second path, reviewed further on in this section, involves invoking the redundancy possible when several smaller machines are used to insure that some sources of adequate power will always be available.

With respect to individual machine reliability, the Gas Research Institute recently commissioned a detailed study of 122 cogeneration units⁴. Of these, those in what they define as "Group 1" - auto-derivative reciprocating engines (26 engines), and "Group 2" - industrial reciprocating engines (34 engines) are relevant to our concerns. They found that these machines, in real-life service, were available 94-96% of the time, with an average mean time between failures of 500 hours (Group 1) and 330 hours (Group 2). This is actually better reliability than is obtained by typical electric utility megawatt-scale power plants.

Furthermore, the researchers were able to identify the causes of the failures and suggest design improvements that should further increase reliability. One completely avoidable but common problem was automatic shut-downs due to water returning from the host facility at too high a temperature - in other words, with the thermal energy incompletely used. Although it may not always be possible to control the host facility, it should be possible to include a completely redundant, automated radiator at modest cost to eliminate this source of outages.

A more serious (and expensive) common problem was engine wrecks "...believed to be caused when jacket cooling water entered the engine cylinders from leaks in the exhaust heat exchangers. This condition, called hydrolocking, usually occurs after the unit is shut down and is especially prevalent in installations having exhaust heat exchangers mounted above the engine."⁵ Another cause of hydrolocking was the use of exhaust manifolds adapted by blocking unused water ports with gasket material alone, easily blown out by high pressure host facility water. These failures can easily be avoided through low cost or no cost design changes.

Other recommendations include using high quality pressure, temperature and flow sensors to avoid erroneous automated shut-downs, maintaining adequate spare parts and using induction generators as starting motors to eliminate all the failure-prone components associated with a separate starter motor. In sum, they argue that the forced outage rate can be reduced from 5.9% to 3.1% at very low cost.

However, harried managers will not want to be faced with even a 3% outage rate if they believe the systems they have in place give them more reliable service. (In fact, this is unlikely, but they may well believe it to be the case.) However, 95% (or 97%) is not necessarily the availability of a well-designed cogeneration system, it is the availability of an individual component, and meeting load with a system of several units, each smaller than the total anticipated load, ensures a much higher level of reliability than one large unit, at comparable cost.

For example, suppose a building or complex has an electric load of 300 kW and a thermal load of 1.5 mmBtu/hr. A single 300 kW cogenerator can meet those loads efficiently, but can be expected to be unavailable 5% of the time, or 440 hours per year. During that time, demand charges for 300 kW will accrue from the local electric utility, and the thermal load will not be served unless an expensive alternative boiler has been included in the system.

If that same building is supplied by five 75 kW cogenerators, each with a 95% availability, the system is much more robust. There is a 23% probability that one of the cogenerators will be down, but the system will still have the 300 kW(e) and 1.5 mmBtu/hr of thermal energy available. It is less likely that a second cogenerator would go down simultaneously: this event (or a worse one) is only expected to occur 1.4% of the time, or 120 hours per year. Furthermore, when it does occur, demand charges will only accrue on 75 kW rather than 300kW, and 1.1 mmBtu/hr will still flow, providing enough thermal energy to keep a building warm or cool or a process in operation at a reduced rate for a few hours while repairs are made.

Of course this system may cost more than the single larger unit, since it is constructed to be 25% over capacity. (There is no reliability enhancement from building a single unit larger than capacity requirements.) However, there is little economy of scale with diesel engines, so installing several smaller units for any given capacity level adds little to the installed system costs. Any small increase is normally paid for through fuel savings, since diesel engines become significantly less efficient at less than half load; being able to switch individual units on and off line ensures that most of them will operate at or near full load and top efficiency much of the time.

2.3 Near-Term New Technology

Table 2-1 indicates that most commercially available natural gas fired systems below 100 kW have fuel-to-electric efficiencies below 30%. Because they are auto-derivative engines, they are restricted to low compression ratios, guaranteeing a low efficiency.

True industrial engines, with bearings and internal structures adequate to support a compression ratio of 15-22:1, are common in larger sizes, from 500 kW up to several megawatts. Natural gas is the fuel of choice where it is available, on the basis of cost and cleanliness, but will not ignite from compression heating even at these high ratios. One solution is to retain a spark plug; another is to inject a small amount of diesel oil, typically 5-10% of full load fuel energy demand, at the top of the compression stroke⁶. This oil ignites reliably and in turn ignites the gas. The relatively slow flame front in the gas-air mixture results in a burn which persists for perhaps the first quarter of the expansion stroke, giving an approximation of the constant-pressure power stroke which characterizes diesels.

The most exciting near-term improvement in small-scale cogeneration technology today is the introduction of these heavy-duty, high efficiency systems in the 50-150 kW range. Increasing efficiency from, for example, 28% to 38% has two important benefits. First, to meet a given electric load, the fuel requirements (and costs) drop by 26%, a significant improvement in the economics. Second, design of cogeneration systems is often made difficult by the fact that in commercial and residential applications, the ratio of thermal to electric loads tends to be lower than the ratio of thermal to electric power available from the machine, leading to "wasted" thermal energy. Increases in electric efficiency bring cogeneration systems into better balance with typical demands, and increase the number of economically viable applications.

Emissions are equally important and improving engine design to minimize "engine out" emissions is an important priority for all manufacturers. Once emitted from the engine there are a range of exhaust pipe options for controlling pollutant emissions. Post-engine control options are discussed in Section 2.6. Engine design changes are discussed in this section.

In natural gas-fired engines NO_x emissions, the primary pollutant of practical concern, can be reduced by operating at very lean air/fuel ratios. The lean limit is constrained by ignition. Under very lean conditions ignition of the fuel air mixture becomes more difficult and the lean limit can be extended by fuel/air charge stratification. This can be accomplished by using a rich precombustion chamber connected to the main chamber which is very lean or charge stratification by air injection into the intake manifold. At very lean average conditions hydrocarbon emissions may be increased and prechamber design is an important factor in this. Practically, NO_x reductions of 90% may be achieved^{7,8}.

With diesel engines, post-engine controls may be considered for CO, hydrocarbons, and particulates (see Section 2.6). There are, however, no practical post-engine controls currently available for the size of engine considered in this study and for this reason emphasis must be placed on reducing engine-out NO_x emissions. Uncontrolled NO_x emissions from diesels range from 10 to 15 g/hp-hr. A variety of measures can be taken for NO_x reduction including retarded timing in combination with higher injection pressures and electronic injection timing and rate control, turbo charging with air to air or air to water undercooling, and, possibly, exhaust gas recirculation. Effective January 1, 1996 manufacturers of engines in the 175-750 HP range for non-highway applications must meet NO_x emission levels of 6.9 g/hp-hr. At least one manufacturer can meet these

limits without turbo charging or gas recirculation. Engines which will not move more often than once each year are exempt from these regulations. In 1997 these regulations will apply to engines in the 100-174 HP range. The point is that these lower NO_x diesel engines are available now for application to the cogeneration market.

Another pollutant of concern with diesel engines is particulates. Measured particulate emissions consist of three parts: solid particulate carbon, soluble organics derived from unburned fuel and lube oil, and sulfates. The carbon and fuel parts of the particulate emissions can be minimized through measures such as injection pressure, head design, and control of lube oil flow into the cylinder. Low sulfur fuels (0.05%) which are now mandated for use in highway diesels can also be used to achieve about 30% reduction in measured particulate emissions.

In some ways dual-fuel engines combine the emission characteristics of both gas and diesel engines and in some ways they present emission problems of their own. In nearly all dual fuel engines the gas is premixed with the incoming air. Diesel fuel used for pilot ignition burns with locally rich stoichiometry and the gas burns lean. Uncontrolled NO_x emissions with dual fuel engines are very roughly 40-60% lower than with diesel engines. The diesel fuel used for pilot ignition contributes greatly to the pollutant emission levels and should be minimized. Many dual fuel engines are simply converted diesels and retain conventional diesel injectors which allow them to operate on 100% diesel fuel at times - a major advantage for the dual fuel option. If operated at very low injection rates atomization quality, and combustion performance degrades. This problem can be avoided through the use of microinjectors, specifically designed to deliver small quantities of fuel. Such microinjectors can be integrated with small, high swirl prechambers to provide reliable ignition. Several microinjector systems are described in detail below. Of course this approach eliminates the possibility of operating with 100% diesel fuel unless two injectors are installed in each cylinder.

At low loads dual fuel engines tend toward very high emissions of hydrocarbons and CO because of the very lean combustion conditions. Options for addressing this include operation only on diesel fuel at low loads, and throttling combustion air.

Detailed tests have been reported on several dual fuel engines, although often in the larger size ranges. Results from several of these are compared in Table 2-2. The first⁹, on a Caterpillar 3406 diesel with a compression ratio of 14.5:1 and a nominal power rating of 200kW (mechanical), compares operation as a standard oil-fired unit with the simplest form of dual-fuel conversion, where gas is simply vented directly into the air intake and diesel oil is simultaneously cut back to amounts that would otherwise be consumed at idle. The result is a modest lowering of efficiency and NO_x emissions, a dramatic increase in CO and a significant decrease in particulates, as measured by drawing the exhaust through filter paper for a set time period and measuring its reflectivity. Each of these effects is amplified at part (50%) load. Throughout the paper the authors emphasize that optimizing parameters such as injection timing should improve performance, but could not be included in that round of tests.

The next test shows that this is indeed the case. Cooper-Bessemer engineers⁷ set up a 408 liter four cycle engine as a standard dual-fuel unit, burning 5.7% diesel oil through the standard injectors and adding natural gas to the air intake. Performance was good, at 41% mechanical efficiency, but NO_x was high at 11.5 g/bhp-h and particulate emissions resulted in an exhaust opacity of 20%, just legal at the time but a source of complaints. They tested various improvements in twenty configurations, of which we mention only two (tests #13 and #21). In the first of these, they installed smaller nozzles dedicated to pilot oil injection; they were too small to allow a return to 100% diesel oil operation, so operations would be restricted to the dual fuel option in a permanent installation, but they provided more precise injection and cleaner burning while efficiency dropped slightly, to 39%.

Engine	Disp	Cyl	Fuel	Load	Eff	NO _x	CO	UHC ¹	PM ²
	(l)		(3)		(%)	(g/hp-h)			(4)
Cat 3406	15	6	DO	Full	36	3.6	1.9		2.3B
" "	"	"	DO	Part	32	4.2	2.6		2.3B
" "	"	"	DF	Full	35	3.2	4.6		0.9B
" "	"	"	DF	Part	26	2.9	10.5		0.6B
Cooper-Bess.	408	6	DF	Full	41	11.5		1.0	20%
" ,sm. nozzles	"	"	DF	Full	39	3.6		4.0	10%
" , Clean Burn	"	"	DF	Full	41	0.9		4.9	< %5
Cat 1Y540	2.4	1	NG	Part	28	0.5		30	
1) UHC = Unburned hydrocarbons 2) PM = Particulate Matter 3) DO = Diesel Oil, DF = Dual Fuel, NG = Natural Gas. 4) B = Bosch Smoke Number (filters), % = Per Cent Opacity									

Table 2-2: Dual Fuel Engine Characteristics.

The "CleanBurn" system in the next line is a more radical step, where the pilot oil is burned in a small chamber where the mixture is kept too rich to encourage NO_x formation. The flame then explodes out into the main chamber, which is held too lean to encourage NO_x formation, but which can none-the-less be reliably ignited by this "torch." Much less pilot oil is used - less than 1% by energy content. The result is 40% efficiency with quite low NO_x and particulate emissions, accompanied by a modest increase in unburned hydrocarbons. This system also retains the standard injectors and so can be switched back to 100% oil operation when gas is not available.

A somewhat similar approach was applied to a Caterpillar 1Y540 all-gas engine and is reported on the next line⁸. Without pilot oil, a spark plug must be used to initiate combustion, but

it ignites a rich mixture of gas in a small "precombustion chamber" which again sends a jet of flame out into the larger combustion chamber, which is filled with a much leaner mixture. The engine was run at low loads, since the purpose was to increase efficiency and decrease emissions in this regime, where very lean mixtures make clean combustion difficult. The cost of using the lean mixture is apparent in the relatively low efficiency rating, while the benefit is apparent in the low level of NO_x emissions. The extremely lean burn results in high levels of unburned hydrocarbons (UHC), which are in fact mostly unburned methane. These losses are significant: since 48.35 grams of methane have a total energy content of one horsepower-hour, the Cat 1Y540's efficiency based on the fuel it actually burned is closer to 33% than to the reported 28%. The authors conclude that "prechamber combustion systems can extend the lean operating limit in natural gas engines."

However, these systems are not yet commercially available in the size ranges we are examining. We conclude that only heavy-duty, high compression engines appear to offer a route to high efficiency at reasonable levels of emissions, and that the introduction of pre-combustion chambers to smaller engines would allow high efficiency operation and lower emissions levels even at part-load operation.

2.4 Competing Technology Options

Several alternative technologies are available which compete with modular reciprocating engine cogeneration and absorption chillers. The most obvious is to continue current use of grid electricity for power and cooling and boilers furnaces for thermal loads. We use this as our basic alternative technology in the analysis to follow. Also, in some of the case studies to follow, we compare the modular cogeneration systems under discussion to a larger (775 kW) reciprocating cogenerator, centrally located and connected to a district heating and cooling piping network.

Another possibility is the use of fuel cells, a technology being pursued in other SERDP programs. We provide a brief review of the current state of fuel cell technology in Appendix D, where we find that despite great technical advantages, without large subsidies they are still too expensive to be competitive currently.

Combustion turbines and large fossil-steam power plants could also serve electric and thermal loads on larger Navy bases, since these systems are only available on a scale of megawatts and larger. These technologies do enjoy substantial economies of scale, so if a Navy base is large enough to make use of the electric power and thermal energy from a ten to one hundred megawatt power plant, they will probably appear more attractive than the 775 kW system. Because they are on such a different scale, however, direct comparisons are complex, and we use only the 775 kW system to compare modular cogeneration systems without thermal distribution to larger centralized systems with thermal distribution.

2.5 Environmental Regulations

Environmental regulations pertaining to internal combustion engines have been examined. Air quality and permitting regulations in California, Maryland, New York, Texas, and Virginia were reviewed for their applicability to systems of the type discussed in this report. In addition, permitting conditions for similar existing equipment were examined. Environmental regulations are highly technical and specific, and the summary of information provided here must be supplemented by site-specific inquiries for any particular project. As an aid to comprehension, we include a table of many environmentally-related acronyms.

In general, new equipment is subject to regulation in each of the states. Regulations are triggered by a combination of size, location, and emission levels. Small equipment is generally exempt; the size that requires permitting varies from state to state. More stringent regulations are invoked if a facility is located in a Prevention of Significant Deterioration (PSD) area or in a nonattainment area. These areas are defined by each state. Permitting requirements may also be triggered if uncontrolled emissions exceed certain levels, as defined by each state, regardless of equipment size.

Controls may be required on new stationary sources. Depending on the specific regulation which applies, these control requirements may be of three types. A review may be required to determine the Best Available Control Technology (BACT) for a particular type

of equipment and pollutant. In nonattainment areas, Reasonably Available Control Technology (RACT) or Lowest Achievable Emissions Rate (LAER) technologies may be required. Specific control technologies are usually determined by a cost-effectiveness analysis or a determination of the types and costs of controls that have been successfully applied.

In certain areas, for example the Northeast Ozone Transport Region, offsets may be required. This means that in order to construct new sources of a given pollutant, existing sources emitting higher levels of that pollutant must be eliminated. Offset ratios vary by state.

AQMD	Air Quality Management District
BACT	Best Available Control Technology
g/bhp-hr	Grams per brake horsepower-hour
IC	Internal Combustion
LAER	Lowest Achievable Emissions Rate
NMHC	Non-Methane Hydrocarbons
NSCR	Selective Non-Catalytic Reduction
PM ₁₀	Particulate Matter, ≤ 10 microns
ppm	Parts per million
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
tpy	Tons per year
VOC	Volatile Organic Compounds

Table 2-3: Environmental Acronyms.

California

There are no statewide regulations in California. The California Air Resources Board provides oversight and guidelines; permitting is done locally by the various regional Air Quality Management Districts (AQMD). Generally, equipment under 50 hp is exempt from permitting requirements. In some districts, exemptions may apply to equipment up to 500 hp.

The South Coast AQMD (SCAQMD)^{10,11} has the most stringent requirements in California and probably in the United States. The SCAQMD includes Los Angeles and Orange Counties, and parts of San Bernardino and Riverside Counties. The SCAQMD requires BACT technology on all equipment. There are different BACT requirements for diesel and natural gas engines. For rich burn (<4% O₂) natural gas engines >50 HP, BACT emission limits are 0.15 g/bhp-hr for NO_x, 0.15 g/bhp-hr for NMHC, and 0.60 g/bhp-hr for CO. For lean burn engines, the NO_x limit is 1.5 g/bhp-hr but 0.3 g/bhp-hr may be required as technology permits. An electric motor is listed as the alternate basic equipment.

For diesel engines <228 HP, BACT guidelines are in terms of control equipment rather than emission limits. An economic analysis is required to determine the cost-effectiveness of selective catalytic reduction (SCR). Otherwise, timing retard greater than or equal to 4 degrees relative to standard timing, and turbocharger with intercooler are required. In addition, fuel oil with less than 0.05% sulfur is required. Rule 1110.2, *Emissions From Gaseous- and Liquid-Fueled Internal Combustion Engines*, sets allowable emission rates in ppm. These depend on the size of equipment, heating value of the fuel, and equipment efficiency. Regardless of the BACT guidelines, it is likely that catalytic reduction would be necessary to achieve these rates.

For diesel engines ≥228 HP, catalytic reduction is required. The SCAQMD lists electric motors, gas turbines, and spark ignited engines as alternate basic equipment to diesel engines, and a comparative economic analysis may be required. The Board's Clean Fuel Policy lists a dual fuel injection engine with methanol and fuel oil as an alternate. It is unlikely that the use of diesel fuel by itself or in a dual-fuel engine could be justified.

Further, annual source tests are required for every engine greater than 50 hp. The New Source Review procedure requires offsets.

Maryland

In Maryland, new equipment is subject to a new source review¹². Permit exemptions are given only for very small, emergency-type equipment.

All metropolitan areas are nonattainment (Baltimore and surroundings - severe; Washington and surroundings - serious) and the entire state is in the Ozone Transport Region, so standards have been extended to outlying areas. In addition, new sources are subject to PSD standards and Federal New Source Performance Standards.

If a new source emits >25 T VOC or HC in the Baltimore or Washington areas, a new source review and a review for RACT are required. Annual NO_x emissions of 25 T in the Baltimore area or 50 T in the Washington area trigger a requirement for BACT and LAER review. In both cases, offsets at a ratio of 1.3:1 are required.

New York

As in other areas, various regulations¹³ are triggered depending on equipment size, emissions, and location. In downstate New York (New York City, Long Island, lower Orange County, Rockland and Westchester Counties), a facility with >200 hp requires a permit; upstate, a permit is required for >400 hp. Note that this is for a facility, so a multiple unit installation could require a permit.

New York is part of the Ozone Transport Region like Maryland. Downstate emissions >25 T/yr of NO_x or VOC require a permit and trigger the nonattainment rule. Upstate the limits are 100 T NO_x or 50 T VOC. This requires LAER technology and offsets. The downstate offset ratio is 1.3:1; upstate, 1.15:1.

Lowest achievable emissions are determined on a case-by-case basis, with the help of the RACT/BACT/LAER Clearinghouse, described later in this section.

Texas

The Texas Clean Air Act^{14,15} requires permits for facilities which may emit air contaminants, but also allows for exemptions for facilities which would not generate significant air pollution. To qualify for exemption, a facility must meet annual emission limits and certain other requirements. In addition, total emissions from the property on which the equipment is located must not exceed certain annual limits and there must be no restrictions on any existing Texas permit for that property that would preclude an exemption. Finally, if Federal regulations are triggered (for example, the project constitutes a new major source or major modification) an exemption is not allowed.

a) Total emission limits

To qualify for a standard exemption, emissions from the proposed facility cannot exceed:

- 250 TPY (tons per year) of CO, NO_x;
- 25 TPY of VOC, SO₂, PM₁₀, or other air contaminants.

For a nonattainment area, emissions from the facility cannot exceed:

- the major modification threshold for CO (100 TPY);
- the major modification threshold for NO_x and VOC (25-40 TPY);
- 25 TPY SO₂;
- 15 TPY PM₁₀.

Maximum hourly and annual emissions need to be calculated, including upstream and downstream changes caused by the project, using AP-42 or other accepted methods.

b) Standard Exemption

Once it is determined that the general qualifications for an exemption are met, conditions for a specific exemption must be determined. Standard exemption six of the regulations is for gas or liquid fuel-fired stationary internal combustion reciprocating engines or gas turbines. Engines and turbines rated less than 240 horsepower do not need to be registered but must meet two conditions.

The first condition describes the fuel:

"Gas fuel shall be limited to: sweet natural gas or liquid petroleum gas, fuel gas containing no more than 10 grains total sulfur per 100 dry standard cubic feet, or field gas. If field gas contains more than 1.5 grains hydrogen sulfide or 30 grains total sulfur compounds per 100 standard cubic feet (sour gas), the engine owner or operator shall maintain records, including at least quarterly measurements of fuel hydrogen sulfide and total sulfur content, which demonstrate that the annual SO₂ emissions from the facility do not exceed 25 tons per year (tpy). Liquid fuel shall be petroleum distillate oil that is not a blend containing waste oils or solvents and contains less than 0.3 percent by weight sulfur."

The second condition requires that there be no violations of any National Ambient Air Quality Standard. Compliance may be demonstrated by one of three methods: modeling, stack height, or property line distance. If modeling is used, either test data or the following ratios must be used:

For stack height, all exhausts must be released at a height at least twice the height of any surrounding obstructions to wind flow. For the third method of compliance, the total of all NO_x emissions from all sources on the property must not exceed the more restrictive of: 1) 250 tpy, or 2) the value (0.3125 D) tpy, where D equals the shortest distance in feet from any existing or proposed stack to the nearest property line.

Device	NO _x Emission Rate (Q) (g/hp-hr)	NO ₂ /NO _x Ratio
IC Engine	Less than 2.0	0.4
IC Engine	2.0 thru 10.0	0.15 + (0.5/Q)
IC Engine	Greater than 10.0	0.2
Turbines		0.25
IC Engine with catalytic converter		0.85

Table 2-4: NAAQS Compliance Ratios

c) BACT

If a permit is required, a BACT analysis must be done. While a BACT determination is facility specific, current BACT guidelines for both lean and rich burn natural gas engines are emission rates of:

NO _x	2.0 g/bhp-hr
CO	3.0 g/bhp-hr
VOC	1.0 g/bhp-hr.

Diesel engines are normally authorized for standby use only.

Virginia

Regulations^{16,17} are triggered by a combination of facility size, location, and emissions rates. It is unclear whether a small dual fuel-fired cogeneration system would trigger some of these requirements, unless located in a nonattainment area. Many parts of Virginia are in various control areas, which require more stringent controls.

The owner of any stationary source which has a permit or is subject to state emission standards may be required to register with the Virginia State Air Pollution Control Board. The owner of any stationary source located in any emissions control area and emitting 25 tons per year or more of volatile organic compounds or nitrogen oxides must submit an annual emissions statement to the board.

Permits are required for stationary sources, unless the source meets the requirements for exemption. Even if exempt, a source must meet emission standards for existing sources or performance standards, whichever is more restrictive. Permits may also be required if a source is located in a PSD or a nonattainment area.

If a permit is required, applications will be subject to a control technology review to determine if performance standards are met. Performance testing is based on U.S. EPA New Source Performance Standards. Best Available Control Technology is required; in nonattainment areas the lowest achievable emission rate is required for major sources (see below).

Stationary Source Permit Exemption Levels

Exemption levels by emission rate are for facilities with uncontrolled emission rates less than:

Carbon monoxide	100 tons per year
Nitrogen dioxide	40 tons per year
Sulfur dioxide	40 tons per year
Particulate matter (PM ₁₀)	15 tons per year
Volatile organic compounds	25 tons per year
Lead	0.6 tons per year.

In addition, there are separate levels specified for toxic pollutants.

Uncontrolled emission rate is defined as the emission rate at maximum capacity without air pollution control equipment. Annual uncontrolled emissions are based on the maximum annual rated capacity (based on 8760 hours of operation per year), unless the source is subject to permit conditions which limit the annual hours of operation. If more than one unit is installed, the sum of emissions would need to be less than the above rates to qualify for an exemption.

Prevention of Significant Deterioration (PSD) Areas

Any stationary source which could emit 250 tons per year or more of any pollutant subject to the federal Clean Air Act or a major stationary source located in a PSD area is subject to additional rules. A major stationary source is defined as one emitting 100 tons per year or more of a pollutant and included in a list of sources. The list includes:

- fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input;
- fuel conversion plants; and
- fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu per hour heat input.

For major sources, best available control technology is required for emissions equal to or greater than the levels shown in Table 2-5.

Pollutant	Emissions Rate (Tons per Year)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter (TSP)	25
PM ₁₀	15
Ozone	40 of VOCs
Total Reduced Sulfur (including H ₂ S)	10
Reduced Sulfur Compounds (including H ₂ S)	10

Table 2-5: Emission Levels for Which BACT is required.

In addition, limits are specified for increases in ambient pollutant concentrations. Permit applications must include an analysis of air quality.

Nonattainment Areas

Regulations require permits for major stationary sources in nonattainment areas. The current list contains no areas classified as severe; the Northern Virginia area is classified as serious. A major stationary source here is defined as:

"Any stationary source of air pollutants which emits, or has the potential to emit, (I) 100 tons per year or more of any pollutant subject to regulation under the federal Clean Air Act, or (ii) 50 tons per year or more of volatile organic compounds or nitrogen oxides in ozone nonattainment areas classified as serious in Appendix K, or (iii) 25 tons per year or more of volatile organic compounds or nitrogen oxides in ozone nonattainment areas classified as severe in Appendix K."

Any source that is major for volatile organic compounds is also considered major for ozone. Again, the total emissions from multiple units must be considered. As above, air quality must be analyzed. Offsets are required. The source must meet performance standards and emission standards.

Performance Standards

All stationary sources must meet performance standards. Performance testing is required per EPA regulations (40 CFR Part 60). Standards and exemption levels, in terms of concentrations, are specified for toxic pollutants. For opacity, no emissions are allowed with greater than 20 percent opacity, except for one six-minute period in any one hour of not more than 30 percent opacity. In addition, all stationary sources must use BACT. In nonattainment areas, LAER is required.

Existing Permit Conditions

EPA's Office of Air Quality Planning and Standards maintains a network of electronic bulletin boards, collectively called the Technology Transfer Network. These bulletin boards cover a range of topics, including air emission inventories and emission factors, test methods, regulatory and training information. One of these bulletin boards, the RACT/BACT/LAER Clearinghouse (RBLC) contains information on RACT/BACT/LAER determinations made around the U.S.

The RBLC contains information about facilities that have received permits from various pollution control agencies; data are entered by the various regulatory agencies and reviewed and maintained by EPA. The RBLC is designed to assist state and local officials in making RACT/BACT/LAER determinations and can also be used by private companies to learn what controls have been required for specific types of equipment. The database contains permit numbers and contact information at the permitting agency, in case more information is desired.

A search of the RBLC was made for any equipment similar to that under investigation in this project. Only one multi-fuel engine was found, and that is a natural gas/propane 200 hp engine, used for nitrogen gas injection and located in California. The permit was issued in 1991, and specifies that only propane or natural gas can be used. The basis for control is BACT-PSD. NO_x emissions are limited to 90 ppmvd at 15% O₂ (uncontrolled 115.2 lbm/d; controlled 15.8 lbm/d) and VOC emissions to 0.44 lbm/h (uncontrolled 46.6 lbm/d; controlled 10.6 lbm/d). Control is with NSCR with a three-way catalyst.

Most of the equipment listed in the dual fuel category is turbines, with the exception of one facility with a digester and one with boilers. The most stringent NO_x limit is on a cogeneration facility with a turbine/generator burning oil or gas, located in Minnesota. The permit was issued in March 1995 and limits NO_x to 4.5 ppm @ 15% O₂ with gas and 16 ppm with oil. The permit basis is BACT-PSD, and SCR is used. The same limit applies to the turbines at the Pilgrim Energy Center in New York, with an estimated start-up date of December 1995. The permit basis is BACT, and the required control method is steam injection followed by SCR. CO, particulate, VOC and NH₃ emissions are also limited. The Holtsville, N.Y. combined cycle plant (150 MW), permitted in 1992, has a NO_x limit of 42 ppm @ 15% O₂.

The NAPA Sanitation District has an IC engine with digester gas and supplementary natural gas. On the basis of BACT-OTHER, NO_x emissions are limited to 1.25 g/bhp-h and precursor organic compounds to 1.0 g/bhp-h.

Limits for natural gas or diesel engines were also examined. Diesel-only engines permitted in 1992 in Philadelphia have NO_x emission limits of 2 g/bhp-h. A large diesel engine in California, permitted in 1993, has a NO_x limit of 6.6 g/bhp-h, is limited to 500 hours of operation per year, and uses a turbocharger, aftercooler, and injection timing retard of ≥ 4 degrees for control. NO_x limits on natural gas engines range from 1.4 to 2 g/bhp-h.

Overall, the RBLC database shows no small diesel/natural gas-fired engines that have received permits. It should be noted, however, that many of the facilities contain multiple turbines or boilers, and the permits set emission limits for the total number installed. Thus while one small engine may not trigger permitting requirements, installation of several at the same facility may.

Summary

Table 2-6 shows emission rates for natural gas, dual fuel, and diesel systems using various levels of control (as discussed in Section 2.6, to follow). For the model system, that is seven 120 kW units, total annual emissions were also calculated. Annual emissions were calculated assuming full load operation for 8760 hours per year, based on Virginia regulations. The results are thus the maximum annual emissions that could be obtained, and are not likely to be achieved in real-time operation. Nevertheless, they allow an overview determination of where permitting and/or control requirements are likely to be triggered.

Annual NO_x and HC emissions from an uncontrolled gas system would trigger permitting requirements in all areas, while controlled gas systems would not. It should be noted that the emission rates for the controlled system do not meet SCAQMD standards, but engines are available which do.

For both the dual fuel and diesel systems, annual NO_x emissions would trigger permitting and control requirements. For Texas, this applies only to nonattainment areas. In New York, the controlled dual fuel system would not trigger requirements in upstate New York but would in downstate areas.

A site- and engine-specific evaluation would be required to determine actual requirements, however this overview suggests that it would be much easier to locate a natural gas-fired system than either a diesel or dual fuel system.

2.6 Options for Reducing Emissions in Engine Exhaust

In any pollution control strategy the first step should be to minimize "engine-out" emissions through engine design and adjustments. The current status of gas-fired and dual-fuel engines in this area is discussed in Sections 2.1 and 2.3. In this section, options for reducing emissions with exhaust gas treatment are discussed for both natural gas and dual fuel engines.

Natural Gas-Fired Engines

With gas-fired, spark ignited engines the basic gas treatment approach used in automobiles may be extended for use in these engines. Early auto catalytic control systems involved lean conditions to reduce CO and hydrocarbon emissions only. These conditions were achieved by adjusting the engine to lean air/fuel ratios and injecting air into the exhaust upstream of the catalyst. In the converter CO and hydrocarbons reacted with available oxygen. This approach was followed by the use of three-way catalysts where conditions at the converter inlet are controlled to provide stoichiometric or very slightly rich gas. In the converter CO and hydrocarbons are oxidized with excess oxygen and NO. This approach for NO_x reduction is sometimes termed Selective Non-Catalytic Reduction or NSCR. In this application it is necessary to maintain very tight limits on engine air/fuel ratio. Zirconium oxide sensors are ideally suited for use in maintaining air/fuel ratio at about stoichiometric because of the large jump in sensor output as air/fuel ratio is reduced toward the stoichiometric limit. Under lean conditions these sensors require precise temperature compensation or other measures to be useful in controlling air/fuel ratio.

Emission Rates												
Engine System:		gas		dual fuel			diesel			diesel		
		conven-	with 3 way	conven-	with OX	with trap/	conven-	with OX	with trap/	comp-	with OX	with trap/
pollutant	units	tional	catalyst +	tional	catalyst	catalyst	tional	catalyst	catalyst	liant	catalyst	catalyst
			EGR [4]									
NOx [1, 2, 3]	g/bhp-hr	11	1	6	6	6	14	14	14	6.9	6.9	6.9
CO	g/bhp-hr	1.6	0.32	2.3	0.46	0.46	3.03	0.606	0.606	3.03	0.606	0.606
Particulates	g/bhp-hr	0	0	0.15	0.09	0.03	1	0.6	0.2	1	0.6	0.2
Hydrocarbons	g/bhp-hr	4.9	0.98	2.4	0.48	0.48	1.1	0.22	0.22	1.1	0.22	0.22

Annual Emissions												
Engine System:		gas		dual fuel			diesel			diesel		
		conven-	with 3 way	conven-	with OX	with trap/	conven-	with OX	with trap/	comp-	with OX	with trap/
pollutant	units	tional	catalyst +	tional	catalyst	catalyst	tional	catalyst	catalyst	liant	catalyst	catalyst
			EGR									
NOx	ton	132.94	12.09	72.51	72.51	72.51	169.20	169.20	169.20	83.39	83.39	83.39
CO	ton	19.34	3.87	27.80	5.56	5.56	36.62	7.32	7.32	36.62	7.32	7.32
Particulates	ton	0.00	0.00	1.81	1.09	0.36	12.09	7.25	2.42	12.09	7.25	2.42
Hydrocarbons	ton	59.22	11.84	29.01	5.80	5.80	13.29	2.66	2.66	13.29	2.66	2.66

Notes:

1. For conventional gas, NOx based on discussions with manufacturers. Can vary from .15 to 1.0
2. For dual fuel, NOx based on test results with the MCC engine and a review of manufacturer's data.
Emissions from dual fuel engines vary greatly and lower emission levels are possible with improved design. See Section 2.
3. For compliant diesel, assumes retarded timing and electronic fuel injection control.
4. Assumes exhaust gas recirculation, a three way catalyst, zirconium oxide oxygen sensor with feedback air/fuel ratio control.
Based on Tecogen low-NOx package.

Table 2-6: Emissions from Alternative Reciprocating Engines.

Applied to natural gas-fired cogeneration engines, three way converter technology can provide very low exhaust emissions, although some special considerations must be made in converter formulation. Gas-fired engine exhaust has considerably higher levels of methane, which is difficult to oxidize. Palladium has a higher activity level for methane than platinum vs. ruthenium, and the palladium/platinum ratio would be higher for gas-fired engines. Relative to other hydrocarbons, methane is not considered as noxious a pollutant. It may not be necessary to realize the same conversion efficiencies for methane and non-methane hydrocarbons emissions.

White et. al. conducted a survey¹⁸ of the durability of eight three-way catalytic converters applied to gas-fired, spark ignited engines. The optimal air/fuel ratio was found to be at about $\lambda = .995$. ("λ" is the ratio of the actual air/fuel ratio to the stoichiometric air/fuel ratio.) At higher values of λ, NO conversion decreases sharply and at lower λ values CO and HC conversion decrease. Conversion levels for CO, total hydrocarbons, and NO_x were about 72%, 40%, and 75%.

Gas-fired cogeneration packages with catalytic converters are now offered. A unit available from Tecogen includes a standard automotive three-way converter with an oxygen sensor and exhaust gas recirculation. This is offered as an optional, low NO_x package. Without the package NO_x emissions are in the range of 11 g/BHP-hr and are reduced to about 1.0 with it. Three-way catalysts are considered to be the least expensive NO_x control option. Johnson Matthey Co. reports over 1000 such systems currently operating on gas-fired engines in gas wellhead compressor applications.

In another approach engines can be operated much leaner, yielding somewhat reduced engine-out NO_x emissions and using a catalytic converter for only CO and hydrocarbon emissions. This is essentially the early automotive approach. System NO_x emissions would overall be higher than with a three-way catalyst because of very low NO_x removal in the converter. In studies with gas-fired heat pump engines, Creamer and Saunders¹⁹ obtained catalyst conversion efficiencies for CO and total hydrocarbons of +90% and 70-90% respectively. An important advantage of this approach, relative to three way catalysts, is avoidance of the need for very close engine air/fuel ratio control.

Dual Fuel Engines

The application of catalytic converters to dual-fuel engines is more difficult than with gas-fired engines because dual-fuel engines run lean, they have soot in the exhaust, and the exhaust gas has a higher sulfur content. Because dual-fuel engines run lean, the three-way catalyst approach cannot be used to reduce the very high NO_x emissions levels with this engine. A great deal of work has been done on the development of catalytic convertors and soot trap systems for diesel engines, and this work is applicable to dual-fuel engines.

With dual fuel engines the diesel fuel used to pilot ignition makes a major contribution to both particulate and NO_x emissions. As discussed in Section 2.1, measures taken to reduce the diesel fuel fraction will improve engine-out emissions.

Typically, particulate emissions from diesel engines consist of three parts: solid particulate carbon, soluble organics derived from unburned fuel and lube oil, and sulfates. Flow-through diesel engine catalytic converters are effective in oxidizing CO, gaseous hydrocarbons, and the part of diesel particulate emissions which are derived from fuel and lube oil. This fraction is often referred to as the soluble organic fraction (SOF). The SOF part of the particulate emissions is engine dependent. Flow through catalysts can reduce measured SOF by 50-70% and total particulates emissions by 5 to 40%^{20,21}. With a catalyst diesel particulate emissions as low as .08 g/BHP hr have been reported and these catalysts have proved durable in extended vehicle engine tests^{22,23}. Light-off temperatures (defined at 50% conversion) for diesel catalytic converters are in the range of 500-700 F. At lower temperatures conversion efficiency falls rapidly and at temperatures over 625 F conversion efficiencies over 80% are reachable for CO and hydrocarbons. In applications where exhaust gas temperature is too low, it may be necessary to use a duct burner or inject fuel into the exhaust pipe, which burns in the converter, raising the effective temperature. In lean diesel engine exhaust these oxidation catalytic converters have no effect on NO_x.

A great deal of work has been done on the development of catalytic and non-catalytic soot traps (ceramic filters) for light and heavy duty diesel vehicles. With both types of traps, achieving temperatures required for trap cogeneration (carbon burnoff) under highly variable load conditions is an important design issue. Some designs have used small diesel-fuel burners, located in the exhaust manifold, to periodically burn-off trapped soot. In other cases electrical heaters are used to periodically regenerate the traps. Soot trap systems have been used in off-road applications since about 1986. If engine cycles are high enough that the engine exhaust temperature is above 930 F for a significant part of the time, non-catalytic traps can be used. With catalytic traps the soot light-off temperature can be lowered to 680 F. A considerable amount of work has been done on the use of fuel additives that contain catalytic metal compounds and can decrease the soot light-off temperature to as low as 530 F²⁴.

Sulfates can have a very significant impact on total measured particulates. Across platinum-based catalysts sulfur oxidation to sulfates, which increases measured particulate emissions, is a concern although palladium catalysts have a much lower conversion efficiency for sulfur. With catalytic emission control systems low sulfur diesel oil (.05%) should be used.

Achievable reductions in emissions with catalysts for particulates, CO, and hydrocarbons are 70%, 98% and 82% respectively²⁵. Detroit Diesel Corporation has applied a catalytic converter to a dual fuel bus engine. Emissions over a standard urban test cycle for particulates, CO, and hydrocarbons have been reported at 0.9, 0.31, and 0.085 g/ghp-hr²⁶.

Dry Systems Technologies²⁷ has developed an emissions control system for mine engines which may be partially applicable to stationary, dual fuel engines. It includes a catalyzed exhaust manifold for CO and hydrocarbon control and a low temperature, inexpensive paper filter for particulates control. An exhaust heat exchanger is used to meet the temperature limitations of the filter.

Selective Catalytic Reduction

With diesel engines, dual fuel engines, and lean-burn gas-fired engines Selective Catalytic Reduction (SCR) can be used to achieve over 80% reduction in NO_x emissions. These systems involve the addition of a reducing agent into the exhaust upstream of the catalyst. In the catalyst zone the reducing agent selectively reacts with NO_x , leading to the products nitrogen and water. The reducing agent commonly used is ammonia either aqueous or anhydrous. A solution of 60% water and 40% solid urea can also be used. The ammonia injection rate must be controlled based on the amount of NO_x present in the exhaust gas. With an insufficient injection rate, NO_x conversion will be poor, while excessive injection rates lead to ammonia slip and unacceptable ammonia emissions. Control can be based on a continuous, on-line NO_x analyzer, or ammonia injection rate can be programmed based on expected engine-out NO_x levels. Ammonia slip levels of 10 ppm are considered acceptable. With SCR the catalyst must operate in the temperature range from 500 to 800°F.

Early experience with SCR on engine applications was marked by technical difficulties²⁸. This has included fouling of the catalyst, ammonia slip, and control problems. Developments during the past 10 years have greatly improved reliability and reduced cost. The cost of an SCR system in 1985 for a 1000 hp engine was estimated to be 5 to 6 times greater than for a three-way catalyst system.

A general expression for SCR systems given by Urban et al is: \$120,000 + \$40 X HP. This is based on 1985. In a more recent article²⁹ Weaver and McGregor suggest \$75,000 + \$101 X kW. Both of these really apply to engines larger than those under consideration in this study.

Currently there is a great deal of interest in the development of systems for reducing NO_x emissions in lean diesel engine exhaust using other reducing agents³⁰. Approaches involve injecting diesel fuel into the exhaust upstream of the converter or operating the engine in a way to greatly increase engine-out hydrocarbons. Catalysts being studied include zeolites, copper, and precious metals.

Caterpillar Co. has recently introduced an SCR system based on ethanol injection into the exhaust, upstream of a catalyst bed. The system reportedly³¹ reduces NO_x emissions from 6.7 to 1.3 g/kWh and is being applied to stationary engines larger than about 500 hp. A microprocessor-based control system is used to monitor NO_x emission levels and control ethanol injection rates.

3. COMPATIBLE ABSORPTION TECHNOLOGY

Absorption chillers are a venerable technology, dating back to the early nineteenth century. Modern metallurgy and chemistry have made them much more reliable than they once were, but because they require large amounts of heat exchange surface, they are still relatively costly. The basic operating principles, involving evaporation and distillation within an evacuated space, are described in many engineering handbooks and will not be repeated here. Broadly, absorption chillers may be divided into "directly fired" units, which burn natural gas or some similar fuel, and hot-water or steam powered units, for which the heat has been supplied elsewhere. For cogeneration systems, the heat is supplied from the cooling circuits of the prime mover, so only hot water/steam powered units are of interest.

Although several different working fluid combinations are possible in absorption chillers, for air conditioning applications the only one in commercial use is a mixture of water and lithium bromide salt. Ammonia is used in refrigeration applications where sub-freezing temperatures are required, since the working fluid is water in lithium bromide systems. The efficiency of ammonia systems is half that of lithium bromide systems, so it is never used in applications such as air conditioning, where low temperatures are not required. Other fluid combinations are under study, but they are all of interest only when high-temperature heat is available, and so are not relevant to engine-fired cogeneration.

Absorption chillers may also be divided into "single effect" and "double effect" units, describing the structure of the distillation apparatus within the chiller. Double effect units make use of the incoming heat twice, and so have efficiencies nearly double those of single effect units (for example, coefficients of performance, or "COP"s, of 1.1 rather than 0.65). They also have higher capital costs, so if the thermal energy is essentially "free", as it is in cogeneration, the effect on the economics is not as great as if fuel were being purchased. We will examine this issue in detail below.

So for application in conjunction with modular cogeneration systems, we will examine lithium bromide, hot-water (or steam) fired absorption chillers, looking at both single and double effect systems. To be consistent with a small number of 65-100 kW prime movers, we will be interested in total cooling capacities of under 100 tons (350 kW_{th}), with unit sizes ranging down to 10 to 20 tons (35-70 kW_{th}). We first examine what is "off-the-shelf" today, then look at systems that may become available in the near future.

3.1 Currently Available Technology

To identify vendors of 20-50 ton* double & single effect units suitable for use in this project we consulted various trade journals and the Thomas Register to develop the list of potential suppliers

* A "ton" of refrigeration refers to the ability to produce one ton of ice per day, and is defined to be exactly 12,000 Btu per hour.

shown in Table 3-1. Inquiry elicited interested response from three of the companies, Sanyo, Yazaki and York. Hitachi has turned all of their operations over to York, and Carrier and Trane only manufacture units of over hundred tons, larger than would be suitable for our applications. One other company, formerly known as Preway/Servel/Arkla and now owned by Robur, produces three to five ton chillers, but only in a directly gas fired configuration, so they are of no use in cogeneration applications.

Company	Location	"Effect"	Size Range (Tons)
American Yazaki	Farmers Branch, TX	Single	5-50
Carrier Corporation	Syracuse, NY	S/D	Large
Hitachi America Ltd.	Tarrytown, NY		--> York
Sanyo/McQuay	Danville, IL	Double	100-1500
Trane Co.	La Crosse, WI	S/D	Large
York International Corp.	Baltimore, MD	Single	120-1200
" " " "	" "	Double	430-1500

Table 3-1: Current Absorption Chiller Manufacturers

A single 75 kW cogenerator, running at 36% electrical efficiency, will provide thermal energy sufficient to power 18 tons of single effect capacity, so we would need about six small cogenerators to power one of even the smallest of the Sanyo or York systems, and the Trane and Carrier machines are similarly oversized for our needs. Of the currently commercially available systems, Yazaki seems to make the only appropriately sized machines, and we focus on them as the paradigm of available absorption technology for small cogeneration systems.

The Yazaki hot water-fired chillers are designed to be as simple and maintenance-free as possible. There are essentially three units, of nominal 5, 7.5 and 10 ton capacities. Clever arrangement of the generator and condenser allows the chiller to operate with no internal pumps, so electricity is used only for control devices, including valves. Of course the hot water supply, the cooling water and the chilled water must be externally pumped through the chiller, and the specifications for the flow rates of the hot water supply and cooling water are quite demanding (-5%, +10%). A wet cooling tower must be supplied separately. Over a thousand of these machines are in service in the U.S., with many more in Japan.

Maintenance involves an annual service visit when controls are checked and the non-condensable gasses are pumped out. If hydrogen is present, indicating corrosion, inhibitor is added; otherwise, there is no internal maintenance. Proper operation of the control system is vital to reliable operation and prevention of crystallization (which can be reversed through appropriate service). Maintenance contracts are available through local engineering firms in most parts of the country.

Performance is typical of single effect machines, with a COP which peaks at 0.65. We have assumed the standard values of chilled water in at 55°F (13°C) and out at 45°F (7°C) and cooling water in at 85°F (29°C) and out at 95°F (35°C). Because performance will depend strongly on the temperature of the hot water from the engine, we present Yazaki's predictions for capacity and COP in graphical form below. The data is for the 10 ton unit; the 7.5 ton unit seems to perform identically, while the 5 ton unit has a COP which is about 14% lower. Since in most applications it would only be used as a "trim" unit, we do not describe it in detail.

The nominal equipment cost for the ten ton unit is \$15,800 in summer, 1995. This represents a steep increase above inflation compared to their prices in the mid-1980's, and the national distributor indicated that engineering firms might be prepared to bargain on the price. Since the actual capacity depends on the temperature of the heat source, the actual capital cost varies from \$1390/ton if the hot water is available at 203°F (95°C) up to \$2450/ton if it is only available at 185°F (85°C). We will use the nominal values of 10 tons at 90°F hot water for our analyses. A cooling tower will add \$2000 for the ten ton unit¹, installation will add 30% onto the chiller cost and overhead and profit will add another 26%², so the installed cost of one Yazaki chiller will be about \$26,700. Installation would be somewhat simpler for a second or third unit at the same location, since pipe routing will already be paid for, but we do not reduce installation costs in this case, since the savings will be very site-specific.

Maintenance requirements are minimal in most cases, consisting of an annual checkup and pump-down; if hydrogen is present during pump-down, indicating internal corrosion, inhibitor is added to the solution at that time. Yazaki representatives assert that with correct annual maintenance, system lifetime should be "many" years. We will take maintenance costs at \$500 per year, representing one day including travel for the first unit at a given site.

In summary, our survey shows that absorption chillers of acceptable quality are available. It would be desirable to have the higher efficiency of double effect systems available in the capacity range below 100 tons, however, and the prices for these small units are far higher than for larger systems. Clearly, less expensive chillers would have a major impact on overall system value.

Figure 3-1: Performance of Yazaki 10 Ton Chillers

3.2 Potential Technology Advances

Yazaki is considering introducing a new chiller/heater combination now available in Japan, but the price will be even higher than for existing units, and Yazaki is concerned that this may prove to be a barrier to market success. We know of no other plans by the established commercial companies to introduce innovative products or to significantly upgrade the designs of current products, or to produce smaller units which would compete with Yazaki's. In short, the market appears to be quite static at present.

Recent work at Brookhaven National Laboratory³ funded by the Gas Research Institute holds out the promise of substantial decreases in the costs of absorption chillers while maintaining the current performance of single effect and double effect systems. Absorption chillers consist largely of heat exchangers, and the basic principle involves the development of heat exchangers made from thin, flexible polymer films and metal foils. The shape of the heat exchangers is maintained by the differential operating pressures. Conceptual designs have been prepared, and model heat exchangers fabricated and tested to the point of proof of concept. The amount of material used in the heat exchangers can be reduced by a factor of two or three, and if the program is carried forward, the result may be capital cost reductions of 25-50%. Such advances will make cogeneration a far more attractive option, but substantial development funds are required to make the technological leap.

The availability of a double effect absorption chiller capable of running on cogenerated heat from a reciprocating engine would also enhance the viability of cogeneration, since double effect systems produce almost twice the cooling power of currently available single effect systems. Here, the changes would primarily be made in the engine, since the operating temperature of the double

effect chiller is largely established by the physical chemistry of lithium bromide brines⁴. A reciprocating engine which could operate with the coolant leaving the engine at 300°F (150°C) and returning to it at 280°F (138°C) could drive a double effect absorption chiller of reasonable cost, producing 70% more cooling power from any given level of reject heat. Operation of an engine under these conditions is perfectly possible in theory, using a mixture of water and ethylene glycol or propylene glycol, but many detailed issues such as lubricant deterioration, local hot spots and optimal coolant circulation remain to be worked out.

In summary, although there are many steps that could be taken to convert the current marginal economic performance of modular cogeneration systems to clear-cut desirability, these steps are a clear prerequisite to further progress and they are not being taken at the current time.

4. MODEL FACILITY DEFINITION AND SIMULATION

4.1 Introduction

A spreadsheet model of a modular cogeneration system was constructed for the sixteen-building system modeled by analysts at Oak Ridge National Laboratory (ORNL)¹. The main difference between the ORNL system and ours is that ORNL always employed a central heat and power system with a district heating and cooling (DHC) system to transport the heat and chilled water to the buildings. Our approach assumes that the DHC system either does not exist or is so decrepit that it requires major repairs, equivalent to a complete re-construction, an option which is examined here. In most of the studies to follow, however, instead of a central cogenerator, smaller-scale "modular" cogenerators are placed in the larger buildings. Heat produced by these cogenerators is used to meet heating and hot water loads, and with the assistance of absorption chillers, to meet cooling loads as well. Heat is not transported between buildings, however, and this means that buildings too small to warrant their own cogenerators are not served by cogenerated heat. In contrast to heat, electricity is easily shipped from building to building, and so on the electrical side it doesn't matter where the cogenerators are physically located.

The approach to assessing energy produced and used to meet heating, cooling, and electrical loads is to use the national-average values for commercial buildings contained in DOE's 1994 Office of Building Technologies Core Data Book² ("OBT"). These annual loads are broken down into hourly rates by means of a piecewise load-duration curve for electrical energy use and piecewise heating- and cooling-load profiles for the buildings.

4.2 Description of Site

The site analyzed by ORNL is a generic facility used for the training of personnel, such as a college campus or a military base. Its buildings have a total floor area of 399,249 ft². Seven large buildings, each with a floor area of 41,520 ft², make up 73% of the floor area of the site, with nine smaller buildings composing the remainder.

4.3 Energy Use Intensities

Energy use intensities were derived from OBT, using 1992 data. Total commercial floor space in that year was 66.1×10^9 ft² [OBT, Table 1.3.3]. Total primary energy use in commercial buildings was 13.07 quads (1 quad = 10^{15} Btu), while site energy use (net of power-plant losses in electricity generation) was 6.79 quads [OBT, Table 1.3.1].

The site energy use was disaggregated [OBT, Table 1.3.2], with total site energy and energy per square foot as follows:

- o Space and Water Heating used 2.69 quads, 97% of which was in the form of gaseous and liquid fuels.
- o Space Cooling (referred to in charts below as A/C or AC) used 0.27 quads, more than 96% electricity.
- o Non-AC Electricity Demands (about half of which was lighting) used 2.56 quads.
- o Other Fuel Demands (cooking, laundry, and other commercial uses) totaled 1.26 quads.

From these values, the heating and cooling loads were determined under the following assumptions:

- o Heating is accomplished largely by boilers with an aggregate seasonal efficiency of 70%. OBT, Table 5.1.6 shows average commercial gas and oil space heating efficiencies for existing stock (1986) of 70% for oil and 71% for natural gas, with new equipment installed that year averaging 71% and 72% for oil and gas, respectively. The actual space and water heating load is then 2.69×0.70 or 1.88 quads.
- o Cooling is accomplished largely by electric-driven chillers having an aggregate Seasonal Energy Efficiency Ratio of 10.36. [OBT Table 5.1.6, 1986 stock]. (New equipment installed in that year had an average SEER of 10.58.) The coefficient of performance (COP) corresponding to this is $10.36/3.415=3.03$, which translates to an annual cooling load of $0.27 \times 3.03 = 0.82$ quads.

Table 4-1 presents these values translated into energy intensities (annual energy per unit floor area). The "other fuels" category reported by OBT is assumed to be independent of whether there is a central heat and power system, modular cogenerators, or individual-building boilers and electric-powered chillers. It is therefore dropped from the remainder of this analysis.

Load Category	Total (10^{15} Btu/yr)	Intensity (Btu/ft ² /yr)
Space and Water Heating	1.88	28,400
Space Cooling	0.82	12,400
Non-AC Electric	2.56	38,700 (11.33 kWh/ft ² /yr)
Note: Intensities are obtained by dividing loads by commercial floor area of 66.1 billion ft ² . In the case of electricity, conversion from Btu to kWh is also carried out.		

Table 4-1: Annual Heating, Cooling, and non-AC Electrical Loads and Energy Intensities for U.S. Commercial Buildings, 1992.

4.4 Cogenerators and Chillers

The analysis is based on a particular choice of commercially available cogenerator, the ISI unit described in Chapter 2, and on the Yazaki ten-ton single-effect absorption chiller described in Chapter 3. Their characteristics may be summarized as:

- o Cogenerator:
 - Electric Capacity 120 kW
 - Electric Efficiency 0.38
 - Thermal Capacity 165 kW_t or 563,000 Btu/h
 - Thermal Efficiency 0.52
- o Absorption Chiller:
 - Cooling Capacity 10 tons or 120,000 Btu/h
 - Coefficient of Performance 0.65
 - Thermal Input 185,000 Btu/h @ 200 F

The thermal input to a chiller is slightly less than one-third of the output from the cogenerator. Therefore a cogenerator could be mated to anywhere from zero to three chillers. The relative magnitudes of heating and cooling loads, together with economic tradeoffs, will dictate the optimal number of chillers to use within this constraint.

4.5 Site Characterization in Terms of Energy Inputs

The site described above is now characterized in terms of the energy inputs required. The energy intensities are translated to annual and average hourly energy inputs required by the whole site, a single large building, the seven large buildings together, and by the aggregate "rest of site." Table 4-2 presents the results:

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	11339 MBtu	1179 MBtu	8254 MBtu	3085 MBtu
Heating, Hourly	1294 kBtuh	135 kBtuh	942 kBtuh	352 kBtuh
Cooling, Annual	4951 MBtu	515 MBtu	3604 MBtu	1347 MBtu
Cooling, Hourly	565 kBtuh	58.8 kBtuh	411 kBtuh	154 kBtuh
Non-AC Elec Annual	4524 MWh	471 MWh	3293 MWh	1231 MWh
Non-AC Elec Hourly	516 kW	53.8 kW	376 kW	140 kW
Note: MBtu = 10 ⁶ Btu; Btuh = Btu/h				

Table 4-2: Annual and Average Hourly Loads for Space/Water Heating, Space Cooling, and Electric Power Not Used for Space Cooling.

4.6 Electric Load Duration Curve

In order to set up the spreadsheet analysis, it is necessary to make an estimate of the variability of the thermal and electrical loads over the course of the year. In the electric case, this is achieved by means of a load-duration curve. Such a curve plots electrical load against the number of hours in which the load is greater than the given value. This gives a monotonic function starting with a y-value equal to the peak load at zero hours and declining to the minimum load encountered during the year at 8760 hours. Although this curve is in reality a smooth function, for the purpose

of this analysis it is convenient to present it in a piecewise-constant fashion, with four pieces each representing an averaged load over some subset of the hours during the year. As a baseline, we will use the curve plotted in Figure 4-1. This assumes five load levels: a peak load equal to 5 times the base load, encountered for a negligible number of hours; a near-peak load equal to 4 times the base load, encountered for 10% of the year; moderate loads equal to 3 and 2 times the base load, encountered for 20% and 30% of the year; and the base load, encountered for 40% of the year. This approximates the general shape of a typical utility load-duration curve. Under this assumption, the base load will equal one-half the average hourly load for the year as given in Table 4-2, with the other steps proportionate to this.

Figure 4-1: Electric Load-Duration Curve Used in Analysis

4.7 Heating and Cooling Load Curves

The heating and cooling loads in this national-average site are expected to be moderate in nature, such as might be encountered in the states bordering the North-South divide, e.g. Virginia, Kentucky, Missouri, Kansas. As a baseline, we have taken the heating and cooling loads to be spread over 5 months each, with the remaining 2 months as a shoulder season having no heating or cooling load. Within the heating and the cooling periods, we have assumed three load levels in the ratio 1:2:3, building up and then down in stepwise fashion 1:2:3:2:1 over the 5-month season. In addition, a narrow peak existing for a negligible number of hours can be assumed at the top of the distribution. This peak will govern the maximum capacity required to meet the load at all times, but will not affect energy calculations. For the purpose of this analysis, we assume this peak to rise to 4 times the lowest step. Because of the five-month duration of the pattern for either load, the hourly load for the lowest step can be calculated as follows:

$$(2)(730)(X) + (2)(730)(2X) + (1)(730)(3X) = 8760 \text{ (Average Hourly Load)}$$

where X is the hourly load for the lowest step (with 2X and 3X the higher-step loads), 730 is the average number of hours per month, and the first two terms have an additional factor of two because there are two steps at each of these levels. This yields:

$$\text{Hourly Load for the Lowest Step} = 1.333 \text{ Average Hourly Load.}$$

4.8 Optimal Installation for a Large Building

We now focus on the heating and cooling needs of a single large building on the site. Because we cannot ship heat or chilled water from building to building, we need to match the thermal generation capacity of a cogenerator as well as we can to the needs of a building.

We would like to perform cooling in the large buildings using absorption chillers mated to the cogenerator. Because the COP of the chiller is less than one, the average thermal input to chillers required to cool the building will be greater than the cooling load cited above in Table 2. In fact, the average thermal input needed to cool a large building with absorption chillers will be 58.8/0.65 or 90.5 kBtu/h.

Using the average thermal inputs for heating and cooling, respectively, of 135 and 90.5 kBtu/h, the steps of the heating and cooling load curves are constructed by multiplying these numbers by 1.33, 2.67, and 4.00 and plotted in Figure 2. Also plotted in the figure are the thermal output of a cogenerator and the thermal input requirement of 1, 2, and 3 chillers.

Figure 4-2: Yearly Plot of Thermal Inputs Needed to Heat and Cool One Large Building. Months 1-5, Heating Load. Months 7-11, Thermal Input Needed to Meet Load with Absorption Chillers.

From this figure we see that, under the assumptions described above, one cogenerator can meet the heating load of the building, except for the short-duration peak which can be met with an auxiliary boiler, as discussed in detail below. (Backup boilers in each building can also carry the heating load in case of cogenerator failure). The cooling load can be met by two chillers in all but the extreme peak situations. Here it might be argued that short-term unmet loads could be acceptable. Alternatively, when a peak-day load is anticipated, the chillers could be run in a control strategy that would overcool the building the previous night and thus provide some thermal storage.

If we do put one cogenerator in each large building, then the site as a whole will have a capacity of seven times 120 kW, or 840 kW. The average electric demand of the site is 516 kW. From the discussion of the electric load-duration curve, the four values of electrical load encountered are 0.5, 1.0, 1.5, and 2.0 times this average value, or 258, 516, 774, and 1032 kW. (A small additional load will be needed to air-condition the smaller buildings that don't have cogenerators.) Thus, the cogenerators can meet the site's electrical needs 90% of the year, and most of its needs the remaining time. It appears that the seven cogenerators are reasonably well matched to the system load profile.

For these reasons, in the analysis to follow, we will assume as a base case that each large building has one cogenerator and two absorption chillers.

4.9 Heating and Cooling the Buildings

The heating load inputs for the seven large buildings are 1.33, 2.67, and 4.00 times 942 kBtu/h for the three levels of heating load. The heat inputs required to meet the cooling load are 1.33, 2.67, and 4.00 times $411/0.65$, with the divisor 0.65 representing the COP of the chillers.

Having decided to heat and cool the large buildings with cogenerators and absorption chillers, we need to know how we will heat and cool the smaller buildings. We assume this is done with individual-building boilers and electrically-driven air conditioners. Therefore, we need to know the electric load due to this demand, which is not included in the "non-AC electric load." The average AC load for the rest of the site, as shown in Table 4-2, is 154 kBtu/h. Assuming this load is met by average equipment with an SEER of 10.36, the average electrical load is 14.9 kW. The loads for the three cooling-load steps are then 1.33, 2.67, and 4 times this value, or 20, 40, and 60 kW.

4.10 Control Strategy

Several control strategies are possible for the cogenerators. Four of these are:

- o Run flat out at all times and sell excess power offsite, e.g. to the local utility.
- o Run to meet the thermal load of the site, using as much of the electrical energy onsite as possible, selling the rest offsite. Purchase any shortfall from the local utility.
- o Run to meet the electrical load of the site, using what thermal energy is available. If excess heat is produced, throw it away. If not enough heat is obtained from the cogenerators, use the boilers for the remainder.
- o Run to meet the larger of the electrical and thermal loads. If the thermal load is larger, sell excess electric power offsite. If the electrical load is larger, throw away the excess heat.

The first of these strategies would maximize the utilization of the cogenerator, and is in fact the strategy that many independent power producers seek to pursue.

The second strategy appears to be suboptimal, in that it would involve shutting down the cogenerators for much of the year or running them at a low level. It is rejected on the basis that it would often require the site to purchase electricity even while cogenerators were sitting idle.

The third strategy should in general be better than the second because electrical energy is more valuable than heat. Thus, controlling on electrical needs should be better than controlling on thermal needs.

The fourth strategy does everything that the third strategy does, but in addition permits additional heat to be gained from the cogenerators for use when needed for space heating or cooling, without the need to fire up backup boilers.

The fourth strategy was selected for the initial analysis because it does better than the second in making the site self-sufficient, while requiring less power to be sold than strategy 1, to a perhaps unwilling customer. Tradeoffs between strategies 1, 3, and 4 need to be analyzed in greater detail, but meaningful results would probably require a more detailed hour-by-hour simulation, which is beyond the scope of this analysis.

4.11 Spreadsheet Analysis of System Operation

The spreadsheet analysis is based on the assumption that the electrical load (net of air conditioning) and the thermal loads of the buildings are statistically independent. That is, there is as much chance of a peak electrical load occurring during a high thermal demand period as during one of low thermal demand. This permits the entire year to be broken down into a 4 X 7 array of

conditions, each holding for a small fraction of the year. The spreadsheet will compute the electrical and thermal demands and outputs of interest for each of these conditions, then add them to get an annual picture of the performance of the modular cogeneration system.

For ease of following nomenclature, electrical quantities are denoted by the letter E, heats by H, and fuels by F. Energy rates in kW or kBtu/h have a prime after the letter, while integrated energy values in MWh or MBtu do not have the prime. Specific quantities within categories are denoted by subscripts.

Inputs to the spreadsheet are as follows:

Global constants: Cogenerator electric capacity in kW (E'_{capacity})
 Cogenerator heat/electric ratio $R_{h/e}$

The spreadsheet then calculates the cogenerator thermal capacity

H'_{capacity} in kBtu/h using the formula $H'_{\text{capacity}} = 3.415 E'_{\text{capacity}} R_{h/e}$

Electrical descriptors (one set of values for each of 4 loads):

Fraction of year at this load (f_e)
 Whole-site non-AC electrical load ($E'_{\text{non-AC}}$), kW

Thermal descriptors (one set of values for each of 7 conditions):

Fraction of year at this condition (f_h)
 Cogenerated buildings heat load (H'_{CgB}), kBtu/h
 Rest of buildings heat load (H'_{RoB}), kBtu/h
 Rest of buildings AC electric load ($E'_{\text{RoB-AC}}$), kW

Given these $2 + 2 \times 4 + 4 \times 7 = 38$ inputs, the spreadsheet proceeds to calculate the following numbers for each of the 28 blocks:

E'_{demand} Site electric demand, in kW, equal to $E'_{\text{non-AC}} + E'_{\text{RoB-AC}}$

H'_{demand} Site heat demand, in kBtu/h, equal to $H'_{\text{CgB}} + H'_{\text{RoB}}$

E'_{cogen} Cogenerated electric power, in kW, equal to the greater of E'_{demand} and $H'_{\text{CgB}}/(3.415 R_{h/e})$, up to the limit E'_{capacity} , i.e. $\min\{\max[E'_{\text{demand}}, H'_{\text{CgB}}/(3.415 R_{h/e})], E'_{\text{capacity}}\}$.

H'_{cogen} Cogenerated heat, in kBtu/h, equal to $3.415 E'_{\text{cogen}} R_{h/e}$.

H'_{used} Useful cogenerated heat, in kBtu/h, equal to the lesser of H'_{CgB} and H'_{cogen} .

Each of these quantities is then multiplied by the number of hours in the block, i.e. $8760 f_c f_h$, to obtain an integrated energy value. For example, the total electric energy used for the block E_{demand} is equal, in kWh, to $8760 f_c f_h E'_{\text{demand}}$. The spreadsheet divides this by 1000 to report MWh. Each block thus contains ten quantities, as follows:

E'_{demand} , kW	E_{demand} , MWh
H'_{demand} , kBtu/h	H_{demand} , MBtu
E'_{cogen} , kW	E_{cogen} , MWh
H'_{cogen} , kBtu/h	H_{cogen} , MBtu
H'_{used} , kBtu/h	H_{used} , Mbtu

Finally, the spreadsheet adds the values of the five right-hand quantities for all 28 blocks, to get annual totals displayed at the bottom. In addition, the amount of electricity that must be purchased is found by adding $E_{\text{demand}} - E_{\text{cogen}}$ for those blocks for which this quantity is positive. Similarly, $E_{\text{cogen}} - E_{\text{demand}}$ added for those blocks for which this quantity is positive yields the amount of electricity that can be sold. The spreadsheet also calculates H_{boilers} , the amount of heat that must be supplied by on-site boilers. This could occur in the cogenerated buildings if the cogenerator's thermal output were insufficient to meet the load at any time, although in the base case this does not happen. The rest of the site must always be heated with boilers. In general, the sum of these two heats is given by $H_{\text{demand}} - H_{\text{cogen}}$.

Not shown on the spreadsheet, but easily calculated, is the fuel F_{cogen} required to run the cogenerator. This will equal, in MBtu, either 3.415 times E_{cogen} divided by the electrical efficiency (0.38), or H_{cogen} divided by the thermal efficiency (0.52). The fuel F_{boilers} needed to fire the boilers is just H_{boilers} divided by the boiler efficiency. We will take this efficiency to be 0.80. F_{total} is the sum of the fuel used by cogenerators and boilers ($F_{\text{cogen}} + F_{\text{boilers}}$).

4.12 District Heating Cogeneration System

In addition to the modular cogeneration systems or the case of local boilers and utility electricity, military bases can be (and often are) served by district heating systems. In these systems pressurized hot water or steam is produced in a central facility and is shipped through insulated pipes to the various buildings. Older systems were often constructed around a central boiler, but most recent installations get heat from a cogeneration plant which also generates electricity, and in regions with appreciable air conditioning load, there will also be a large absorption chiller driven off the cogenerator when there is cooling load, with chilled water shipped around the base in a separate set of insulated pipes. With such a system, even the heating and cooling loads of the smaller buildings can be supplied through cogenerated heat, allowing an improvement in fuel efficiency compared to the modular systems, which are limited to the larger buildings.

A spreadsheet describing such a system is included in Appendix B and the results are included in the discussions below. The treatment was similar to that for the modular systems with the

following exceptions: 1) All Rest of Buildings Heating and AC Electric Loads (RoB Ht Ld and RoB AC Elec Ld) were set to zero, since heated and chilled water now supply heating and cooling to these buildings; 2) These thermal loads were added to those in the "cogenerating buildings"; and 3) All thermal energy supplied to the district piping system equaled demand divided by 0.8, corresponding to an 80% efficiency in the piping system. The result, as can be seen in the spreadsheet or in the summary tables, is a system which makes better use of its reject heat, but one for which the first costs are higher, as will be discussed in the next chapter.

4.13 Base Case Results

The spreadsheet for the base case with two absorption chillers per cogenerator is displayed as Table B-1 in the Appendix and summarized in the fourth column of Table 4-3. For this base case, the annual electricity used on the site was 4652 MWh. The cogenerators produced 4972 MWh. Because of time mismatches between production and consumption, 181 MWh had to be bought and 502 MWh were available to be sold. It is worth noting that about half this amount (229 MWh) was available (net sales - purchases) during the periods of highest thermal demand in the heating and cooling seasons. Even though we have posited independence of the thermal and non-AC related electrical demands on the site, offsite electrical and thermal demands are expected to be positively correlated due to the presence of heat pumps, resistance heating, and electric-powered air conditioners offsite. An offsite utility might look with favor on a cogenerator that has so much of its available power at just such times.

The other salient result is that, of 23 345 MBtu of heat cogenerated, 13 790 MWh was used, or 59% of the total. This is a very respectable utilization factor for cogenerated heat in a buildings-related application.

It was also desired to study the effect of using fewer than two chillers per cogenerator. Spreadsheets for a system identical to the base case, but with fewer chillers per cogenerator, are shown in Figures B-2 and B-3 of the Appendix. Table 4-3 compares the salient results for the three cases, along with a comparison case in which there is no cogeneration, all electricity is purchased and all heating is done with on-site boilers. The demands for electricity and heat in this case will be the same as for the cogeneration case with no chillers.

Finally, the results for the DHC system are presented in the fifth column of Table 4-3. It is clear that the ability to transport thermal energy allows substantial improvements in system efficiency - 78% of cogenerated thermal energy is used, a very high overall efficiency. Fuel consumption is higher than for the other cases, but this is because more electricity is sold back to the utility, resulting in less fuel being consumed off site.

4.14 Primary Energy Comparisons

We now compare the primary energy for energy under each of the five cases shown in Table 4-3. Primary energy of fuel is rated at the energy content of the fuel in MBtu. Primary energy of electricity is obtained by multiplying the net purchased electricity (purchases minus sales) by the factor 3.415 to convert MWh to MBtu and by 3.159 to account for power-plant and transmission losses. [OBT Table 1.1.1] The primary energy totals for each system are shown in Row 12 of Table 3. It can be seen that the cogenerating systems save 31% to 34% of the primary energy used by the non-cogenerating system, with the greatest savings for the system with the most chillers. The effect of chillers on primary energy savings is not large in percentage terms, however. For the DHC system, primary resource consumption is substantially lower than for the other cases studied, since now the off-site fuel saved by electricity sales is included in the accounting.

4.15 Demand calculations.

In addition to the spreadsheet calculations of various modes of energy production just presented, assessment of the comparative economics of these energy supply systems requires knowledge of the peak thermal and electric demands they will make, since this determines the required capacities of the cogenerators, chillers and boilers. In this section we derive these peak demands, again using a simple spreadsheet model. (Note that although "kW" and "Btu/hour" were used in the previous discussion, they always referred to average power over some extended time period. In this discussion we refer to the peak power called for during a month or some similar period.)

The calculation is presented in Table 4-4. The first column consists of titles, to be discussed below. The four central columns indicate the peak power or required capacity for one of the seven large buildings, for one of the nine small buildings, the site totals (derived differently for different quantities as discussed below) and the units for that line. The next column indicates how many ten-ton absorption chillers are associated with each cogeneration unit at the large buildings. To keep the amount of calculation reasonable, we assume that the nine small buildings are identical.

Cogen (y/n): Chillers/cogen.	No	Yes 0	Yes 1	Yes 2	Yes DHC
Annual Energy Flows					
1. E_{demand} , MWh	5 000	5 000	4 744	4 652	4 520
2. H_{demand} , MBtu	11 333	11 333	15 400	16 872	23 684
3. E_{cogen} , MWh	0	5 137	4 945	4 972	5 527
4. H_{cogen} , MBtu	0	24 123	23 219	23 345	25 954
5. H_{used} , MBtu (% of H_{cogen})	0	8 252 (34%)	12 319 (53%)	13 790 (59%)	20 119 (78%)
6. E_{bought} , MWh	5 000	264	201	181	225
7. E_{sold} , MWh	0	401	401	502	1 232
8. $H_{boilers}$, MBtu	11 333	3 081	3 081	3 081	3 564
9. F_{cogen} , MBtu	0	46 138	44 440	44 683	49 641
10. $F_{boilers}$, MBtu	14 166	3 851	3 851	3 851	4 455
11. F_{total} , MBtu	14 166	48 785	48 291	48 534	54 096
12. $E_{primary}$, MBtu	68 100	47 260	46 130	45 070	43 239

Table 4-3: Annual Energy Quantities for the Model Facility for Various Numbers of Chillers for Each Cogenerator and for the Use of District Heating and Cooling.

The heating demands are developed in the upper block of the table, and of course do not depend on how many absorption chillers are present. The heating load is assumed to have the basic shape shown in Figure 4-2 and discussed above, with five temporal components of equal length, here taken to be months. To make the loads consistent with the total annual energy consumption (as explained above), the (period) average load during the first and fifth steps was taken as 1.333 times the (annual) average load, the (period) average loads during the second and fourth periods was twice that and the (period) average load during the third, central period was three times the first step. However, to calculate demand, we also assume that during each period there is an additional load, of height equal to the first step but of negligible duration. Pictorially, for each building, each demand period has the line indicated in Fig. 4-2 added to it, and although fuel consumption in meeting this load will be negligible, the capacity of the equipment must be adequate to ensure that it can be met.

These "spikes" represent both the one cold night that may show up in an otherwise temperate period in an average year, and the likelihood that every few years there will be an exceptionally cold winter. We also assume such spikes exist in the month before and the month after the first and last non-zero heat loads, labeled as months "6" and "12" in Figure 4-2.

This concept then allows the "Annual Peaks" for individual "large" and "small" buildings to be derived from the annual energy data. This "Annual Energy" is taken from Table 4-2 and inserted into the upper block of this table. Then, for a given building, the

$$\begin{aligned}\text{Annual Peak} &= 4 * (\text{First period average load}) \\ &= 4 * (4/3) * (\text{Annual average load}) \\ &= 4 * (\text{Annual Energy}) / (1.314 * n),\end{aligned}$$

where "n" is the number of months in the heating season (here, five, but variable in later analysis) and the Annual Peak is in thousands of Btu per hour while the annual energy is in millions of Btu.

The resulting peaks give accurate specifications for boilers and cogeneration systems for single buildings, but for the district system we must add the loads together, and here the diversity of the peak demands is important. If they were to all occur at the same time, the correct answer would be the sum of the individual peaks, or $7*718 + 9*209 = 6907$ kBtuh. On the other hand, if the "spike" loads were truly of negligible duration and were not correlated with each other, only the five period loads of non-zero duration would add together coherently, and all the individual building spikes would occur at different times, so only one representative of the largest of these would contribute. In this case, the system peak demand would equal $7*(3/4)*718 + 9*(3/4)*209 + (1/4)*718 = 5360$ kBtuh. Because neither of these extreme cases is likely to be correct, we incorporate a "Diversity Factor" which interpolates linearly between them, and for these studies leave it set at 50%. The result is the 6130 kBtuh total site peak demand shown in the table.

Annual peak cooling demand (in kBtuh) is calculated in a completely analogous way in the next section of the table, including the same diversity calculation for the total site cooling demand. The required capacity of chillers (other than the modular ten-ton absorption units) is then calculated for the case of no modular absorption chillers for large and small buildings and for the whole site by simple conversion at 12 kBtuh per ton. Thus peak demand that must be supplied by a central chiller in the DHC case is 223 tons, which, when increased to compensate for 20% thermal transmission losses, requires a 280 ton absorption chiller. Similarly, large buildings require 26 tons of electric chilling capacity and small buildings require eight tons. If ten-ton absorption chillers are installed in the large buildings, their capacity requirements drop accordingly, but since the buildings are not connected thermally in this case, there is no change in the small building demands and the total site demand is not meaningful.

In the next section of Table 4-4 the non-AC electric demand is calculated from the total annual non-AC electric energy in Table 4-2, assuming the load duration curve shown in Figure 4-1. As explained above, the height of each step must be one-half the annual average power, here 258kW.

As for the heating and cooling loads, we assume that the load duration curve is topped by a spike of negligible duration and energy, but the same height as one step. Again, these spikes arise more or less independently in the individual buildings. The non-AC electric demand for the entire site is calculated by summing the individual building demands for the sections of the load with significant energy consumption and adding the spikes using a 50% diversity factor, calculated just as for heating and cooling.

In the next section, the total electric demand for individual buildings and the entire site is calculated by adding together the non-AC electric demands discussed in the previous paragraph and the electric demand required to meet the cooling demands developed in the paragraph before that, still assuming an SEER of 10.36. Again, the loads corresponding to non-zero energy blocks are simply summed, adding together in each cooling period the peak non-AC electric load and the corresponding electric load for AC. However, the spikes in non-AC and AC based electric demand are completely uncorrelated, so here the diversity factor is taken as zero. The result is a peak demand of 1175 kW in the five months when there is no cooling demand whatsoever, and for shoulder months where the non-AC demand spike is greater than the AC demand spike. Moving into the cooling season, the peak load increases as shown, mitigated by the presence of seven, fourteen or twenty-one absorption chillers.

Finally, in the bottom block of the table, the power provided by the cogeneration units is subtracted off to leave the peak power required from the utility, against which demand charges will be levied. We will see below that it is economically advantageous to include one or more "extra" generation units to shave peak load; the calculation shown in the table is thus for nine cogenerators, although the extra two are not assumed to provide any thermal energy, since thermal demands in the buildings they occupy are probably already met. The final upshot is that with, for example, one absorption chiller for each of the first seven cogenerators, there is one month with a peak utility load of 236 kW, two months with utility peaks of 163 kW and nine months with peak loads of 95 kW.

	Large Building	Small Building	Total for Site (1)	Units	Number of
# of Buildings:	7	9			10 ton
Heating Demand:	Diversity	Factor =	50%		Absorption
5 Month Season					Chillers per
Annual Energy:	1179	343	11339	MBtu	cogen unit
Annual Peak:	718	209	6130	kBtuh	
Cooling Demand:	Diversity	Factor =	50%		
5 Month Season					
Annual Energy:	515	150	4951	MBtu	
Annual Peak:	314	91	2677	kBtuh	
Capacity	26.1	7.6	223	tons with	0
Requirement	16.1	7.6		tons	1
	6.1	7.6		tons	2
	0.0	7.6		tons	3
Electric Demand with EER= 10.36 Btu/Wh, DF= 50%					
There are	2.0	2.0	2.0	1.0	months
when P(AC)=	40.2	112.9	185.6	258.4	0
(in kW)	40.2	40.2	107.9	180.6	1
	40.2	40.2	40.2	102.8	2
	40.2	40.2	40.2	40.2	3
Non-AC Electric:	Large	Small	Total		DF= 50%
Annual Energy	471	136	4524	MWh	
Peak Demand:	134	39	1175	kW for	5 months
Total Electric Demand DF= 0%					
There are	2	2	2	1	months
when P(tot)=	1175	1248	1321	1394	0
(in kW)	1175	1175	1243	1316	1
	1175	1175	1175	1238	2
	1175	1175	1175	1175	3
Utility Demand with 9 120 kW cogenerators:					
There are	2	2	2	1	months
when P(tot)=	95	168	241	314	0 and
(in kW)	95	95	163	236	1 5
	95	95	95	158	2 with
	95	95	95	95	3 95
1 See discussion of diversity in text.					

Table 4-4: Development of Peak Thermal and Electrical Demands for the Model Facility.

4.16 Comparative Emissions of Pollutants

It is useful to evaluate the total impact which the implementation of cogeneration can make on total pollution emissions. For this purpose three scenarios from Table 4-3 have been selected. This includes the baseline in which there is no cogeneration, the case of cogeneration with a single chiller, and the case of cogeneration integrated with district heating. Included in the comparison are emissions from the off-site utility, emissions from the engine, and emissions from the on-site boiler used to provide heating. To estimate the utility emissions an oil-fired boiler with an electrostatic precipitator was assumed. For particulates it was simply assumed that the boiler just meets the current EPA New Source Performance Standard limit of 0.03 lb/MMBtu. Emission factors for other pollutants were taken from EPA AP 42, 1995. In the case of the engine a spark-ignited gas engine with a three way catalyst for emissions control was assumed. Emission factors were as listed in Table 2-5. The on site boiler was assumed to be fired with natural gas and again emission factors were taken from EPA AP 42. Table 4-5 below provides a summary of the emission factors used in this comparison in common units.

Emission Factors per unit of fuel energy input				
		utility	on-site boiler	engine
particulates	lb/MMBtu	.03	0	0
NO _x	lb/MMBtu	.447	.133	.324
CO	lb/MMBtu	.0334	.033	.105
hydrocarbons	lb/MMBtu	.00695	.0055	.322

Table 4-5: Emission Factors Used in Comparing Total Amounts of Pollution Produced by Three Scenarios.

Table 4-6, below lists the results of the comparison. Negative numbers for particulates in the two cogeneration scenarios result from the sale of more electric power back to the utility than was purchased from it, leading it to generate less electricity. Also, while the total amount of emissions is important, facilities must consider the total amount of emissions produced on site. Table 4-7 below is a modification of Table 4-6 in which off-site utility emissions are not considered.

		baseline-no cogeneration	cogeneration with 1 chiller	cogeneration integrated with district heating
particulates	tons/year	.75	-.03	-.15
NO _x	tons/year	12.16	7.00	6.08
CO	tons/year	1.07	2.36	2.51
hydrocarbons	tons/year	.21	7.16	7.97

Table 4-6: Comparison of Total Amount of Pollutant Emissions with Three Selected Scenarios

		baseline-no cogeneration	cogeneration with 1 chiller	cogeneration integrated with district heating
particulates	tons/year	0	0	0
NO _x	tons/year	.94	7.40	8.39
CO	tons/year	.23	2.40	2.68
hydrocarbons	tons/year	.039	7.17	8.00

Table 4-7: Comparison of Total Amount of On-Site Emissions with Three Selected Scenarios

These calculations indicate that the cogeneration systems enjoy a substantial advantage with respect to NO_x when total emissions are considered and because they burn only gas, with particulates. However, the incomplete burning characteristic of internal combustion engines leads to significant increases in CO and hydrocarbons. (The hydrocarbons are largely unburned methane.) Which pollutants are most significant will depend on local conditions. However, when only on-site emissions are considered, cogeneration's advantages with respect to NO_x emissions are no longer apparent. At this time the environmental permitting process described in Chapter 2 is the only legally significant descriptor of acceptable emissions, but many cogenerators view the EPA's failure to account for reduced utility emissions a major institutional barrier to increased energy efficiency.

5. COMPARATIVE ECONOMIC ANALYSIS FOR THE MODEL FACILITY

5.1 Introduction

In this chapter we combine the technical simulation results for the model facility derived in the previous chapter with realistic comparative capital and operating costs to determine the relative economic merit of the various systems being investigated. Using the simplest case of local boilers and purchased utility electricity as a starting point, we calculate both the additional capital investment and the annual savings associated with the various modular cogeneration schemes and with the district heating and cooling (DHC) plant. For each case we then calculate two "figures of merit": a simple payback, which is simply the incremental capital divided by the annual savings, and the twenty-year return on investment (ROI), which is the effective interest being paid on the capital investment by the annual savings.

We will see that the results are somewhat marginal. The modular cogeneration systems show a modest 5% ROI. (Since all calculations are in constant 1995 dollars, inflation must be added to this before comparing it to alternative investments.) The DHC system is comparable under the most favorable assumptions, and is sometimes not viable. However, bear in mind that these are results for national average energy quantities. Far more meaningful results will be presented in the following two chapters, where this analysis is applied to the climates of particular Navy divisions. Even then we would caution against using this or any similar study to determine specific investment decisions; choices about what energy system will be best can only be made in the context of site-specific engineering studies. Work such as is presented here can be used to help decide where such engineering studies should be carried out first, and to establish technical needs requiring research and development, and we will point to these results as they emerge.

5.2 Economic Assumptions

The simplicity of the ROI approach allows us to base the analysis on one economic assumption: we use a study life of twenty years. This period is a sufficiently long period to expect capital intensive projects to pay for themselves, and is appropriate for a large, stable institution such as the Navy. The ROI then represents the return generated by the additional capital needed to install a more energy efficient system, return realized as annual savings in fuel and electric bills. If "K" is the additional capital, "A" the annual operating savings and "n" the number of years (here, 20), then

$$K/A = [1 - (1 + \text{ROI})^{-n}] / \text{ROI}.$$

This transcendental equation must be solved iteratively for ROI, but this is accomplished automatically by spreadsheet subroutines. The ROI is of course the return on the investment over and above that needed to pay off the original capital.

Because the annual savings are largely lowered electric costs, they can be expected to increase more or less with inflation. The ROI is calculated using the annual savings in 1995 dollars, and hence represents a constant dollar return. An expected rate of inflation (perhaps 2% for electricity) should be added before the ROI is compared with other investments not discussed in this study. More importantly, the ROI is primarily suggested as a means of comparing results within this study.

The other economic assumptions are displayed in Table 5-1. Electricity costs include service, demand and energy charges, and are proportional to those of Gulf Power, to be discussed below. However, both the energy and the demand charges have been scaled up so that the average cost of electric energy (that is, the total electric bill divided by the total kilowatt-hours delivered) comes out equal to the national average cost of electricity in the commercial sector, 7.46 ¢/kWh¹. We assume in this chapter that power can be sold back to the utility for one-half this rate, or 3.73 ¢/kWh.

Electricity Costs: Gulf Power (Pensacola)	
Energy:	\$0.0398 /kWh
Demand:	11.61 /kW-mnth
Ratchet:	1 months
Service:	\$227 /month
Purchases	\$0.0373 /kWh
Fuel Cost:	
Gas:	\$0.474 /therm
	= \$4.74 /MBtu
Service:	\$50 /month
Economics:	
Inflation:	Use constant 1995 dollars
Study duration:	20 years

Fuel costs refer only to natural gas, and we use the national average rate of \$4.74/MBtu², with an added monthly service charge of \$50, which has a negligible impact on the economics.

Table 5-1: Economic Assumptions for Model Facility.

5.3 Equipment Costs

The portfolio of available equipment is displayed in Table 5-2. The 120kW units are the ISI spark-ignited natural gas machines discussed in Chapter 2. Both the capital equipment cost and the O&M are manufacturer's prices, and the O&M charge includes regular replacement or rebuilding of the units as they age.

	Equipment (\$1000's)	Installation (\$1000's)	Overhead & Profit	— Cooling Tower — Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
210 kBtuh	5.9	3.4	2.1			11.5	0.5
720 kBtuh	14.2	6.8	4.2			25.3	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
280 ton AC(1):	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
8 ton	9.3	1.6	1.8	11	2.0	14.7	0.8
16 ton	13.4	2.8	2.7	Inc.		19.0	0.9
26 ton	18.1	3.2	3.6	Inc.		24.9	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0
1) Capacity incremented to cover 20% losses in DHC system.							

Table 5-2: Equipment Costs

Any generator that is to run when there is no or low thermal demand must have a radiator to eliminate the thermal energy; since this can be done at engine temperatures (180-190°F), the radiator will have a lower unit cost than the cooling towers associated with air conditioning. Its capacity is nonetheless measured in "tons", as for all the cooling towers*.

The 775 kW cogenerator, used in the DHC system, is also a spark-ignited reciprocating engine, albeit much larger. It is typical of units available from Detroit Diesel, Waukeshaw or several other manufacturers. The installed cost, derived from DOE sources³ and updated to mid-1995 dollars⁴ is consistent with those used in the ORNL study cited previously⁵.

Three different sizes of boilers are needed to suit the various configurations. The installed capital costs are derived from estimating manuals⁶ and the O&M costs, principally for cleaning, are based on estimates of one to four person-days per year, consistent with the cleanliness of natural gas.

* "Tons" refers to the capacity a compression chiller with a COP of about 3.0 could have with this cooling tower dissipating all the reject thermal energy, so one ton of heat dissipation capacity equals 12,000 Btuh*(1+1/3.0) or 16,000 Btuh.

The ten ton absorption chillers are the Yazaki units discussed in Chapter 3. The capital costs are from Yazaki, with estimated installation expenses⁶ added. The 280 ton absorption chiller, used in the DHC system, is priced completely from estimating manuals. Three different sizes of compression chillers are needed to fit the various configurations, and their capital costs are also broken out from estimating manuals as indicated.

Finally, the district heating system costs are far too uncertain to assign a specific number to, depending as they do on many site-specific factors. Here we are only considering the costs of piping and associated heat exchangers, since the energy sources have been itemized. High cost could arise because of difficult, rocky terrain or because of many pre-existing infrastructure components (gas and telephone lines or roads) that must be avoided. If the system is replacing a deteriorated but existing district heating system, costs may be lowered because the trenches must be dug to remove old pipe, and perhaps some of it may be salvageable, but the installation of the cooling water circuits will still be costly. The amount of speculation that can go on in the absence of a particular site is endless and expensive, so rather than attempt to work up any detailed roster of costs for particular systems, we draw on previous work to determine a range, where most district heating and cooling distribution systems can be expected to have installed capital costs lying within that range.

The previous work, a recent BNL study⁷, examined several district heating and cooling system configurations and found that the cost of a system delivering hot water was \$2.60-7.00/MBtu, which would correspond to a capital cost for this 11340 MBtu/year system of \$295-794k. (Capital costs were annualized at 10% per year in that study.) In the same study, for a system delivering 4950 MBtu of cold water per year, the cost of adding the cold water piping was found to be \$6.80-17.60/MBtu of delivered chilled water, corresponding here to an additional capital cost of \$337-871k. These costs (for delivering chilled water) may seem high, but they are realistic. The basic problem is that there is only a ten degree temperature swing as the chilled water travels through the system. Consequently, three to five times as much water must be moved per MBtu as in the case of hot water distribution. Combining these uncertainties following the methods of the earlier study⁸ we find that capital costs will likely range between \$780k and \$1515k, and we work out the economic consequences of being at both ends of this range in the analysis to follow.

These piping expenses are substantial amounts of money, and to further validate them we examined the system defined in the ORNL report⁹. A figure in the report showed the rough layout, and assuming that the buildings were separated by distances comparable to their sizes, we laid out a very rough distribution network and found about 6000 feet of pipe trench was needed, with four times that much pipe. Our costs from the previous paragraph then imply a unit cost of \$130-250 per foot of trench, consistent with figures from estimation manuals⁶ when the need for insulation, drainage, expansion sections and the other complexities of DHC are taken into account.

5.4 Analysis for Boilers and Utility Electricity

The first case examined was that of local boilers in each building and utility electricity. It is certainly the system with lowest capital cost, and the equipment is described in Table 5-3. Each large building gets a large (720 kBtuh) boiler, and we here simplify the model facility by assuming that each of the nine small buildings are identical and can be served by one 210 kBtuh boiler. Capital and variable (O&M) costs are taken from Table 5-2 by multiplying by the number of boilers in each case. Fuel costs are found by multiplying the fuel use indicated in Table 4-3 (broken out by building type as in Appendix B) by the natural gas price in Table 5-1.

Cooling is supplied by a single compression chiller for each building, sized to meet the cooling demands developed in Table 4-4; again the nine small buildings are treated as if they were identical.

The annual cost of electricity is developed in detail. First the monthly service charge from Table 5-1 is multiplied by twelve (months) and entered as a fixed annual amount. Then the "Total Electric Demands" for each month from Table 4-4 are multiplied times the demand charges in Table 5-1 and entered in Table 5-3 under "Demand"; this is the annual cost. The "Non-AC Annual Electric Energy" (Here, 4524 MWh) is taken from Table 4-2 or 4-4 and is added to the electric energy required by the compression chillers, derived by dividing the total Annual Cooling Energy from Table 4-2 or 4-4 (Here, 4951 MBtu) by the national average seasonal energy efficiency rating (SEER) of 10.36. This sum is then multiplied by the energy charge to calculate the annual total spent on energy charges (here, \$199k).

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effci
Boilers:				
9 210 kBtuh	103	4.5	18.3	80%
7 720 kBtuh	177	4.2	48.9	80%
Compression Chillers				
9 8 ton	132	7.2		
7 26 ton	174	7.0		
Electricity				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	171	199	373	0.0746
Totals:				
Capital outlay:		\$586 k		
Annual Outlay:		\$463 k		

Table 5-3: Boilers and Utility Electricity

These three quantities are then summed to give the total annual electric bill (Here, \$373k). This total is then divided by the total energy delivered to derive the average cost of a kilowatt-hour, including all demand and fixed charges. It is this number that we set to the national average cost of electricity, 7.46 ¢/kWh by adjusting the energy and demand charges for the model facility in Table 5-1.

The various quantities are then separately totaled to give the one-time capital outlay (here \$586k) and the annual operating costs (here \$463k). These are not the total cost of operating the energy plant for the model facility. They only include components which will be replaced if the

modular cogeneration system or the DHC system are employed instead of the boiler/utility electricity system. Items such as thermal and electric distribution within each building are completely omitted since they will be the same, or nearly the same. These costs will serve as a meaningful basis for comparison between the systems discussed in this report; because of the many omissions, they should not be used for comparison of these systems with other conceptual designs which may have included more or less detail in their calculations.

5.5 Analysis for Modular Cogeneration

A similar analysis for modular cogeneration is presented in Table 5-4. Many quantities are treated just as they were in Section 5.4, and will not be described in detail again. Here each of the seven large buildings has one 120 kW cogenerator, while two other 120 kW units are on site somewhere but are not assumed to produce useful thermal energy. These two additional units are included because the analysis reported just below indicates that under the assumptions of Table 5-1, the system pays substantial demand charges to the utility if it has only seven generation units. Because these units are used at very low load factors and are not assumed to cogenerate, their variable O&M charges are taken as one-half those used in the first seven units, presented in Table 5-2. Their capital charges are not reduced.

The thermal output of the cogenerators is not adequate to meet the peak heating demands of the large buildings (Table 4-4), but in contrast to the situation with boilers and utility electricity (Section 5.4), the large buildings now need only the smaller 210 kBtuh boilers, so capital costs for boilers are somewhat reduced. There are no absorption chillers, and the system is served by the same set of compression chillers as in the boilers and utility electricity case.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effc.
Cogenerators:				
9 120 kW	990	112	226	38%
Boilers:				
16 210 kBTuh	183	8	18	80%
Absorption Chillers:				
0 10 tons	0	0		0.65
Compression Chillers:				
9 8 ton	132	7		3.03
7 26 ton	174	7		3.03
Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	20.9	3.8	27.4	0.104
- Sales:			(15.0)	(Income)
Totals:				
Capital outlay:		\$1,479 k		
Annual Outlay:		391 k		
Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$893 k		
Annual Savings:		72 k		
Simple Payback:		12.3 years		
Return on Investment:		5.1%		

Table 5-4: Modular Cogen, No Absorption Chillers.

Electricity accounting is performed as it was for the case of boilers and utility purchases, except that now the demand is obtained from the lowest rectangle in Table 4-4, where the demand met by the nine cogenerators has been subtracted out. The result, shown in Table 5-4, when totaled and divided by purchased energy, is that the purchased energy costs 10.4 ¢/kWh. This dramatic increase (from 4.74 ¢/kWh) is due to the low load factor of the residual purchases. The total capital and total annual outlays are summed and presented as before.

In the lowest section they are compared to the case of boilers. The "incremental capital outlay" is the amount by which "total capital" just above exceeds the "total capital" for the case of boilers. The "annual savings" are the amount by which the "annual outlay" for the case of boilers exceeds the "annual outlay" just above. "Simple payback" is just the incremental capital divided by the savings, since the ROI is the constant dollar interest rate obtained when the savings are treated as levelized payments on a debt the size of the incremental capital. Thus the raw capital, with no interest, would be returned in 15.5 years, and an agency which invested an extra \$1479k to build this system would see a net return on its investment of 2.5% over twenty years.

As mentioned above, two extra generators are included in the system, giving a total of nine. These could either be located in one of the seven large buildings as spares, or elsewhere on site. They could perhaps be located in one of the smaller buildings and provide useful thermal energy there, but we have not assumed this, since their presence can be justified solely on the basis of electrical savings. This is demonstrated in Table 5-5, where the results of calculations for this system with seven through eleven cogeneration units are displayed. For each case we show the total cost of purchased electricity and the incremental capital and annual savings relative to the case of boilers and purchased electricity, and the derived simple payback, as explained just above. The simple payback is shortest for nine generators, although the differences are small, and we have found that this choice seems optimal or nearly optimal for all the systems examined in this report.

# Cogenerators:	7	8	9	10	11
Incremental Capital (\$k):	673	783	893	1003	1113
Electric Purchases (\$k):	68	47	27	13	7
Annual Savings (\$k):	53	63	72	80	78
Simple Payback (years):	12.6	12.5	12.3	12.5	14.2

Table 5-5: Economic Performance versus Number of Cogenerators

We then examined a system with seven ten-ton Yazaki chillers included, as shown in Table 5-6. The absorption chillers allowed a reduction in the compression chillers required to meet peak cooling loads in the large buildings, so the associated capital increment is less than bare cost of the absorption units. O&M costs increase somewhat, but the cost of purchased electricity drops by nearly \$7k, and fuel costs go down \$8k. The overall result is that the capital cost of the system has increased by \$145k, while operating costs have decreased by \$12k. Looking at the system as a whole, this has resulted in an insignificant increase in the simple pay back and a tiny decrease in the ROI. Looking only at the additional chillers, one can easily calculate from Tables 5-5 and 5-6 that their incremental capital costs were \$145k, and that they saved about \$12k per year, giving a simple payback of 12 years and offering an ROI of 5.6%. Absorption chillers, at these prices and in this national average/model facility case, seem to be an investment comparable to the modular cogeneration system itself - an investment a careful planner will find worth making, but not a terribly exciting one.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators:				
9 120 kW	990	112	218	38%
Boilers:				
16 210 kBtuh	183	8	18	80%
Absorption Chillers:				
7 10 tons	187	4		0.65
Compression Chillers:				
9 8 ton	132	7		3.03
7 16 ton	133	6		3.03
Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	16.5	1.3	20.5	0.078
- Sales:			(15.0)	(Income)
Totals:				
Capital outlay:		\$1,625 k		
Annual Outlay:		378 k		
Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$1,039 k		
Annual Savings:		85 k		
Simple Payback:		12.3 years		
Return on Investment:		5.2%/year		

Table 5-6: Modular Cogen with One Absorption Chiller.

Note that these calculations are for the only small absorption chiller available in the U.S> today, available at what we consider to be a high price compared to what is possible. Calculations similar to those above, but based on a 25% reduction in the cost of the chiller unit indicate that payback periods would be reduced to six to seven years and ROI's increased to 12-14%, making the chillers a much more interesting investment. This kind of price reduction could probably be brought about without technical breakthroughs, simply by hard bargaining for large numbers of chillers. It is certainly possible if development money is directed at cost reduction.

We also examined the case where two absorption chillers are added for each cogenerator, and the results are displayed in Table 5-7. The incremental savings at the bottom of the table indicate that this system is somewhat less attractive than the system with one absorption chiller per cogen unit. A careful look, however, indicates that the second absorption chiller is a very bad investment under these conditions. The capital outlay has increased by \$157k, while the annual outlay has also increased! Not only do the chillers not save money, but their small maintenance costs outweigh their electricity savings, making them undesirable even if capital costs were zero.

Under the assumptions used here, of national average thermal and electric loads and prices and the equipment costs enumerated above, modular cogeneration does appear to be a

desirable option, and systems with one absorption chiller per cogeneration unit appear to be optimal. As we cautioned above, this result should only be used to indicate that these systems are worthy of further study; the regional studies to be presented in the next two chapters will further refine our assessments of where and under what circumstances modular cogeneration should be pursued at the level of engineering studies.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators:				
9 120 kW	990	112	219	38%
Boilers:				
16 210 kBTuh	183	8	18	80%
Absorption Chillers:				
14 10 tons	373	7		0.65
Compression Chillers:				
16 8 ton	235	13		3.03
0 16 ton	0	0		3.03
Electricity - purchases				
Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
2.7	14.0	0.5	17.3	0.086
- Sales:			(15.0)	(Income)
Totals:				
Capital outlay:		\$1,782 k		
Annual Outlay:		379 k		
Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$1,195 k		
Annual Savings:		84 k		
Simple Payback:		14.2 years		
Return on Investment:		3.5%		

Table 5-7: Modular Cogen with Two Absorption Chillers

5.6 Analysis for District Heating and Cooling System

Before proceeding to regional studies, we briefly examine an obvious competitor to modular cogeneration, centralized cogeneration with "district heating and cooling" (DHC), a system of insulated pipes to distribute heated and chilled water around the base. We have discussed the equipment costs and given a brief description of the DHC system above. Again, because the cost of the piping system depends so strongly on many local variables, we work out the economics for two

systems, one near the upper limit of expected piping costs, the other near the lower limit. The results are in Table 5-8.

The large capital requirements of the DHC piping system result in substantial capital outlays in both cases. At the low end of the piping cost spectrum, the capital outlay is comparable to that for the modular cogeneration system with one chiller per cogen unit, but at the high end of the cost spectrum it is nearly 50% higher. The annual outlay is quite similar to that of the modular system, so the overall comparison, either in terms of simple payback or ROI, favors the modular system slightly over the low-cost DHC system and greatly over the high-cost DHC system.

We would like to emphasize that we do not regard this comparison as a demonstration that "modular cogeneration is better than DHC"; such categorical statements are meaningless for systems as individual and complex as energy supply systems. We have demonstrated, we believe, that on the basis of national average statistics, in bases where the

installation or major overhaul of a DHC system is being studied, a conceptual study of a competitive modular cogeneration system will be worth carrying out.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerator:				
1 775 kW	485	90	235	38%
0 120 kW	0	0	0	38%
Boilers:				
1 5000 kBtuh	104	2	21	80%
Absorption Chiller:				
1 280 tons	354	2		0.65
DHC Pipe, etc.:				
max:	1515	15		80%
min:	780	8		80%
Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	55.8	9.0	67.5	0.300
- Sales:			(46.0)	(Income)
Totals:		Max	Min	
Capital outlay:		\$2,458	\$1,723	k
Annual Outlay:		387	380	k
Comparison to Boilers & Utility Electricity:				
		Max	Min	
Incremental Capital Outlay:		\$1,872	\$1,137	k
Annual Savings:		76	83	k
Simple Payback:		25	14	years
Return on Investment:		NA	4%	

Table 5-8: District Heating and Cooling System

In the following chapters, we examine modular cogeneration systems in different climatic and economic regions to see where they are most likely to be advantageous. Because the same factors - fuel and electric prices and thermal loads - will tend to make both DHC and modular cogeneration more or less valuable, and because of the great uncertainty in piping costs, we have not examined DHC systems in all the different regions. However, Table 5-8 indicates that DHC systems and

cogeneration systems can be quite close in value, so we recommend a side-by-side evaluation of both systems at any site where either appears to be promising.

6. MODULAR COGENERATION IN THE NAVY

6.1 Introduction

The preceding analysis of modular cogeneration, using national-average energy-use data for commercial buildings showed that modular cogeneration offered an attractive alternative to conventional boilers and utility electricity. The questions remain whether these results are applicable to military energy-use conditions, and in what climates these technologies will prove most attractive. In this chapter we carry out simulations of the operation of modular cogeneration systems using actual data characterizing Navy activities. In the following chapter we perform an economic analysis based on the results of these simulations. To carry out this program, we made use of data on energy use in the Navy, which were made available to us through the Energy Audit Report (EAR) database.

The Navy maintains the "Navy Energy Works" bulletin board to provide assistance and information to its energy managers. One of the functions of the bulletin board is the EAR system. This microcomputer data system allows energy managers to report energy consumption, cost, and building floor area as required by Federal policy.

Navy energy use by fuel type is collected for each individual shore activity on a monthly basis and reported quarterly. Data are available for each individual activity and also in several aggregated forms. For this analysis, we chose data aggregated by Engineering Field Division (EFD), which is based on geographical area. Altogether about 400 locationally distinct energy-using activities are included in the seven EFD's, some of which may be subdivided into two or more reporting categories.

The Navy's seven EFD's are given the acronyms CHESDIV, LANTDIV, NORTHDIV, SOUTHDIV, WESDIV, SWESTIV, and PACDIV. These are (for the most part) geographically contiguous regions into which the Navy's various activities are grouped. CHESDIV comprises activities mostly in the Washington, DC area, including nearby areas in Maryland and Virginia. LANTDIV includes the Navy's extensive facilities in coastal Virginia as well as a smaller number of activities in surrounding states. It also includes activities on foreign soil in the Atlantic and Mediterranean. NORTHDIV includes New England, the Middle Atlantic states, and the Midwest. SOUTHDIV stretches from South Carolina to Texas, with a major concentration in Florida. WESTDIV activities are mostly in northern California and Washington State. SWESTDIV comprises the extensive range of Navy activities in San Diego and other parts of southern California. PACDIV is composed mainly of Navy activities in Hawaii, Guam, and Japan.

For each of these EFD's, we obtained a data set for calendar 1994 that broke energy use down into categories of facilities. Some of these categories were not buildings-related. These include "cold iron," which is ships at the dock that take power from shore; transmitters; simulators; and miscellaneous. These were not included in the analysis. Another category not included was "GOCO," which means "Government owned, contractor operated" facilities. For most EFD's the

GOCO category was a small fraction of the total, and in one the energy use numbers were so large as to represent a special case.

The remaining categories represented housing and work areas operated by the Navy and the Marine Corps: Navy Housing, Marine Housing, Marine Activity, and Shore Activity. For each of these categories a 12-month summary of energy use by fuel is given, including electricity, natural gas, fuel oils of various types, propane gas, coal, and steam and hot water. The unit cost of each energy input was also given, as well as the total dollar cost of that fuel. The total area of buildings in each category was also given.

In addition to the annual summary, monthly and quarterly breakdowns were also provided. These proved crucial in separating out the space-heating and air-conditioning components of the energy use. Finally, we were also able to obtain a listing of the activities located in each of the EFD's. This allowed us to assess the average size of an activity in terms of its annual energy use and building floor area, to compare with the typical multi building facility used in our earlier analysis. If the average Navy activity were much smaller than this typical multi building facility, we would worry that the results might not be applicable. On the other hand, if the Navy's administrative units were orders of magnitude larger than our typical multi building facility, one could be concerned that the modular cogeneration approach might strike managers as being too incremental to address their larger concerns. In fact, we concluded that the average Navy activity in the EFD's are three to six times as large, in terms of building area, as our typical multi building facility. Because our approach is modular, the results should scale to the Navy's activities without much distortion. Moreover, using a somewhat smaller base than the Navy's average has the advantage that its results are applicable even to smaller-than-average administrative groupings, while at the same time scaling linearly to larger ones, because of the modularity of the approach.

6.2 Annual Summaries

The first step was to summarize the energy-use and pricing information for each of the categories within each EFD, and thereby to obtain EFD-wide averages. These summaries are shown in Tables 6-2-1 through 6-2-7. Each table gives a breakdown of the locations of Navy activities within the EFD. Also, the availability and price of natural gas is brought out, because of our use of a natural-gas fired cogenerator in the analysis.

Within each table, Column 1 is total building area. Column 2 is electricity, in Gwh, delivered to the site, while column 3 converts this to primary energy (fuel at the power plant) using DOE's standard heat rate of 11 000 Btu/kWh. Although primary energy is not an input to our later analyses, which emphasize dollar cost, it does enable us to compare the energy intensities (energy use per unit area) of buildings in the Navy with the national average for commercial buildings. We wanted first to make sure that our numbers were reasonable, and second to see if there were any discernible differences between the Navy and the civilian sector with regard to total primary energy use.

Column 4 gives total fuel use (other than electricity), while column 5 adds fuel to electricity-primary to obtain total primary energy. Columns 6 and 7 give the price of electricity and the average price for fuel paid by each category within the EFD. These fuel prices were obtained by averaging the fuel prices for the individual fuels used, as given in the Navy data set, weighted by energy content of the fuel.

The first four rows of each table give these quantities for each category within the EFD. Row 5 gives the EFD totals. For columns 1-5, these are just the sums of the individual numbers for the categories listed above. The electricity and fuel prices are averages weighted by electricity and fuel energy use, respectively, for each of the four categories.

Row 6 gives the energy-use quantities for an average-sized activity in the EFD, obtained by dividing the Row 5 totals by the number of activities in the listing mentioned above. Row 7 gives energy-use totals per million square feet, so that comparisons between EFD's will not be skewed by the differences in building areas among them. Finally, Row 9 gives national-average values for commercial buildings, per million square feet, as given in the OBT Data Book.

The total primary energy in Gbtu per million square feet (which is the same as kBtu per ft²) is given in Row 7, with the national average value (198 kBtu/ft²) just below it. For four of the EFD's, the Navy's energy-use intensity is much higher than the national average; for two it is about the same; and for one it is less.

Table 6-2-1 Summary of Navy Data for CHESDIV

In CHESDIV, 27 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

DC 7 MD 16 VA 4

In addition, there was one cogeneration activity listed.

Natural gas comprised 49% of fuel use at an average cost of \$5.90/MBtu.

Category	Building Area (10 ⁶ ft ²)	Elec Site (GWh)	Electricity Primary (GBtu)*	Fuel (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	3.74	24	268	80	348	59.88	6.52
Marine Housing	2.41	21	234	255	489	50.95	1.70
Marine Activity	6.27	94	1043	1320 **	2363	48.39	3.41
Shore Activity	30.70	700	7700	4011	11711	56.51	5.50
TOTALS	43.12	840	9244	5668	14912	55.49	4.85
PER ACTIVITY	1.60	31.1	342	210	552	----	----
PER 10 ⁶ ft ²	-----	19.5	217	131	346	----	----
NAT'L.AVG.***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes 24 GBtu of steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

Table 6-2-2: Summary of Navy Data for LANTDIV

In LANTDIV, 83 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

VA 40

NC,WV,MD,KY,PR 13

FOREIGN (ATLANTIC, MEDITERRANEAN) 27

No cogeneration activity was listed.

Natural gas comprised 23% of fuel use at an average cost of \$4.02/MBtu

Category	Building Area (10 ⁶ ft ²)	Elec Site (GWh)	Electricity Primary (GBtu)*	Fuel ** (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	20.85	169	1859	1288	3147	66.71	6.03
Marine Housing	8.38	150	1646	0	1646	63.14	n/a
Marine Activity	23.59	352	3874	2355	6229	50.63	3.30
Shore Activity	79.09	1318	14495	6100	20595	57.20	4.05
TOTALS	131.91	1989	21874	9743	31617	57.29	4.13
PER ACTIVITY	1.59	24.0	264	117	381	----	----
PER 10 ⁶ ft ²	-----	15.1	166	74	240	----	----
NAT'L.AVG.***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes no steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

Table 6-2-3: Summary of Navy Data for NORTHDIV

In NORTHDIV, 51 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

NEW ENGLAND 16

MIDDLE ATLANTIC 22

MIDWEST 13

No cogeneration activity was listed.

Natural gas comprised 50% of fuel use at an average price of \$3.97/MBtu.

Category	Building Area (10 ⁶ ft ²)	Elec Site (GWh)	Electricity Primary (GBtu)*	Fuel ** (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	16.74	113	1238	1444	2682	83.97	4.40
Marine Housing	0.41	4	39	23	62	61.00	4.16
Marine Activity	0.16	2	20	6	26	148.23	5.00
Shore Activity	69.27	978 ^{\$\$}	10758	8340	19098	48.56	3.93
TOTALS	86.58	1097	12055	9813	21868	52.43	4.00
PER ACTIVITY	1.70	21.5	236	192	429	----	----
PER 10 ⁶ ft ²	-----	12.7	139	113	253	----	----
NAT'L.AVG.***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes no steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

^{\$\$}Note 4: Adjusted for anomalous value of electricity use in the fourth quarter. Fourth quarter set equal to base-year (1985) value increased by average increase of other three quarters over their base-year values.

Table 6-2-4: Summary of Navy Data for SOUTHDIIV

In SOUTHDIIV, 94 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

FL 38 GA 9 SC 16 LA 9 TX 6 TN,AL,MS,AR 10

In addition, there was one cogeneration activity listed.

Natural gas comprised 75% of fuel use, at an average price of \$3.39/MBtu.

Category	Building Area (10 ⁶ ft ²)	Elec- Site (GWh)	tricity Primary (GBtu)*	Fuel (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	17.70	193	2126	417	2543	54.07	4.98
Marine Housing	2.96	36	399	85	484	50.54	6.89
Marine Activity	11.76	142	1563	1121	2684	45.95	3.02
Shore Activity	73.39	1429	15718	4691**	20409	48.32	3.80
TOTALS	105.81	1800	19806	6314	26120	48.79	3.78
PER ACTIVITY	1.13	19.1	211	67	278	----	----
PER 10 ⁶ ft ²	-----	17.0	187	60	247	----	----
NAT'L.AVG.***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes 641 GBtu of steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

Table 6-2-5: Summary of Navy Data for WESTDIV

In WESTDIV, 65 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

CA (north) 37 WA 21 AK,ID,NV 4

In addition, there was 1 cogeneration activity listed.

Natural gas comprised 77% of fuel use at an average price of \$2.71/MBtu.

Category	Building Area (10 ⁶ ft ²)	Elec-Site (GWh)	Electricity Primary (GBtu)*	Fuel ** (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	22.40	178	1956	994	2950	52.51	4.98
Marine Housing	none						
Marine Activity	none						
Shore Activity	83.68	1090	11992	6530	18522	47.87	2.91
TOTALS	106.08	1268	13948	7524	21472	48.52	3.18
PER ACTIVITY	1.63	19.5	215	116	330	----	----
PER 10 ⁶ ft ²	-----	12.0	131	71	202	----	----
NAT'L.AVG. ***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes 67 GBtu of steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

Table 6-2-6: Summary of Navy Data for SWESTTDIV

In SWESTDIV, 47 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

CA (south) 43

AZ,NM 3

No cogeneration activity was listed.

Natural gas comprised 77% of fuel use at an average price of \$4.70/MBtu.

Category	Building Area (10 ⁶ ft ²)	Elect-Site (GWh)	ricity Primary (GBtu)*	Fuel (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	17.09	74	815	482	1297	76.92	7.03
Marine Housing	16.04	95	1040	515	1555	90.99	5.73
Marine Activity	35.14	361	3970	1651**	5621	79.21	4.05
Shore Activity	46.11	609	6694	2346**	9040	69.61	4.98
TOTALS	114.38	1139	12519	4994	17513	74.91	4.95
PER ACTIVITY	2.43	24.2	266	106	373	----	----
PER 10 ⁶ ft ²	-----	10.0	109	44	153	----	----
NAT'L.AVG.****	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Marine and Shore Activities include 194 and 839 GBtu of steam and hot water, respectively.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

Table 6-2-7: Summary of Navy Data for PACDIV

In PACDIV, 59 activities were represented in at least one major category with buildings (Navy and Marine housing and shore activities, but excluding ships, GOCO's, simulators, transmitters, and miscellaneous). These were distributed geographically as follows:

HI 23 GUAM 11 JAPAN 19 OTHER 6

No cogeneration activity was listed.

Natural gas comprised less than one percent of fuel used.

Category	Building Area (10 ⁶ ft ²)	Elec- Site (GWh)	Electricity Primary (GBtu)*	Fuel ** (GBtu)	Total Primary (GBtu)	Elec. Price (\$/MWh)	Fuel Price (\$/MBtu)
Navy Housing	19.05	252	2768	756	3524	90.86	6.19
Marine Housing	4.85	41	455	49	504	97.97	12.71
Marine Activity	26.33	343	3771	579	4350	138.58	4.80
Shore Activity	41.79	656	7218	2103	9321	95.64	5.50
TOTALS	92.02	1292	14212	3487	17699	106.18	5.63
PER ACTIVITY	1.56	21.9	241	59	300	----	----
PER 10 ⁶ ft ²	-----	14.0	154	38	192	----	----
NAT'L.AVG.***	-----	12.9	142	59	198	74.57	4.84

*Note 1: Site electricity converted to primary electricity using a power-plant heat rate of 11,000 Btu/kWh.

**Note 2: Includes no steam and hot water.

***Note 3: National average energy-use values in kWh/ft² or kBtu/ft². Electricity price and average of oil and gas price, respectively, in \$/MWh and \$/MBtu (not per square foot).

6.3 Seasonal Breakdowns

In order to use the Navy data in an analysis similar to that performed on the typical multi-building facility using national-average data, we needed to know specifically what the space-heating and air-conditioning loads were for the Navy buildings. Because these were not broken out separately, we decided to make use of the fact that these two loads are seasonally dependent. The simplifying assumption was made that the seasonal variation in fuel use was due to space heating demands, while the seasonal variation in electricity use was due to space cooling demands. The calendar quarter with the lowest fuel use was taken to represent a fuel-use baseload (consisting of various forms of process heat and hot water) while anything above that in other quarters was taken to represent space heating. The first test of this assumption was whether the maximum fuel use always occurred in the winter quarter while the minimum was in the summer. It turned out that this was true for all of the EFD's. Similarly, for electricity, the highest use was always in the summer quarter, while the lowest was in either the winter or spring quarter.

Tables 6-3-1 through 6-3-7 show the quarterly breakdowns of electricity and fuel use. For fuels, natural gas, fuel oils, and other fuels are shown separately. Following each table, a 14-step process of pulling out the seasonal loads is shown. In lines 1-3, electricity use for air conditioning is obtained by subtracting four times the minimum quarterly electricity use from the annual use. This is then converted to an air-conditioning load (line 4) by multiplying by the national-average SEER of 10.36 Btu/Wh. Line 5 gives the building area (from Tables 6-2-1 through 6-2-7). Line 6 shows the air-conditioning load per square foot of building area. Line 7 obtains the non-AC electricity use as Line 2 divided by Line 5.

Lines 8-14 deal with fuel use in an analogous way. Fuel uses other than space heat are called "process heat." They are taken as the minimum quarterly fuel use multiplied by four (line 9), and subtracted from total fuel use (line 8) to obtain space-heat fuel use (line 10). The space heat load is then obtained by multiplying by an assumed average boiler efficiency of 0.7. Finally, the space-heat load per unit area is obtained by dividing this by the building square footage (line 12). The process heat load and load per square foot are shown in lines 13 and 14.

For the special case of CHESDIV and LANTDIV, a combined analysis is shown following Table 6-3-2. It was judged reasonable to combine these two EFD's because the building area for CHESDIV was much less than for the other EFD's and because they are in the same geographical region. It was also the case that the space heating intensities for CHESDIV and LANTDIV were quite different, for unknown reasons. This was the only real anomaly encountered in the procedure, and it was judged better to strike an average by combining the two EFD's.

Table 6-3-1. Quarterly Breakdowns of Electricity and Fuel Use in CHESDIV

	Electricity (GWh)					Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	7	5	24	168	204	31 9	53	347 19 12	896 590 117	2074
3Q	5	5	19	169	198	7 6	13	123 2 3	288 492 96	1030
4Q	7	7	30	191	235	1 3	8	95 7 2	155 238 183	692
1Q	5	5	22	173	205	14 9	182	114 585 9	202 545 206	1866
Yr.	24	22	95	701	842	80	256	1318	4008	5662

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Note: Other fuel in Shore Activity is 99% coal.

Table 6-3-1a: Extraction of Heating and Cooling Loads for CHESDIV

1. Total Electric	842 GWh
2. Non-AC Electric 198 X 4	792 GWh
3. AC Electric [1]-[2]	50 GWh
4. AC Load [3] X 10.36	518 GBtu
5. Bldg. Area	43.12 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	12000 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	18.4 kWh/ft ²
8. Total Fuel	5662 GBtu
9. Process Heat Fuel 692 X 4	2768 GBtu
10. Space Heat Fuel [8]-[9]	2894 GBtu
11. Space Heat Load [10] X 0.7	2026 GBtu
12. Space Heat Load/ft ² [11]/[5]	47000 Btu/ft ²
13. Process Heat Load [9] X 0.7	1938 GBtu
14. Process Heat Load/ft ² [13]/[5]	44900 Btu/ft ²

Table 6-3-2: Quarterly Breakdowns of Electricity and Fuel Use in LANTDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	42	51	72	312	477	257 188 15		410 1 438	1603 599 250	3761
3Q	41	29	86	311	467	213 78 9		210 4 280	718 412 100	2024
4Q	48	39	106	363	556	191 34 5		137 4 274	644 290 91	1670
1Q	38	30	89	332	489	221 64 12		249 11 338	748 520 125	2288
Yr.	169	149	353	1318	1989	1287		2356	6100	9743

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Note: No fuel used in Marine Housing.

Note: Other fuel in Marine Activity and Shore Activity is 98% coal.

Table 6-3-2a: Extraction of Heating and Cooling Loads in LANTDIV

1. Total Electric	1989 GWh
2. Non-AC Electric 467 X 4	1868 GWh
3. AC Electric [1]-[2]	121 GWh
4. AC Load [3] X 10.36	1254 GBtu
5. Bldg. Area	131.91 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	9 500 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	14.2 kWh/ft ²
8. Total Fuel	9743 GBtu
9. Process Heat Fuel 1670 X 4	6680 GBtu
10. Space Heat Fuel [8]-[9]	3063 GBtu
11. Space Heat Load [10] X 0.7	2144 GBtu
12. Space Heat Load/ft ² [11]/[5]	16300 Btu/ft ²
13. Process Heat Load [9] X 0.7	4676 GBtu
14. Process Heat Load/ft ² [13]/[5]	35400 Btu/ft ²

Table 6-3-2c: Extraction of Heating and Cooling Loads in CHESDIV and LANTDIV Combined

1. Total Electric	842 + 1989	2831 GWh
2. Non-AC Electric	792 + 1868	2660 GWh
3. AC Electric	50 + 121	171 GWh
4. AC Load	518 + 1254	1772 GBtu
5. Bldg. Area	43.12 + 131.91	175.03 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]		10 100 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]		15.2 kWh/ft ²
8. Total Fuel	5662 + 9743	15405 GBtu
9. Process Heat Fuel	2768 + 6680	9448 GBtu
10. Space Heat Fuel	2894 + 3063	5957 GBtu
11. Space Heat Load	2026 + 2144	4170 GBtu
12. Space Heat Load/ft ² [11]/[5]		23 800 Btu/ft ²
13. Process Heat Load	1938 + 4676	6614 GBtu
14. Process Heat Load/ft ² [13]/[5]		37 800 Btu/ft ²

Table 6-3-3: Quarterly Breakdowns of Electricity and Fuel Use in NORTHDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	30	1		245	276	451 358	15	4	2155 1555 25	4563
3Q	27	1	1	235	264	117 158	5	1	592 1030 3	1906
4Q	29	1	1	260	291	36 59	2		412 536 3	1048
1Q	26	1		238*	265	135 129	2		984 1039 4	2293
Yr.	112	4	2	978	1096	1443	24	5	8338	9810

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

*Note: The value reported, 533 GWh, was not consistent either with other quarters of the referenced year nor with baseline values from 1985. A corrected value increasing the baseline by the average of the percentage increase of the other three quarters from baseline was substituted as more representative of an average year, regardless of whether the stated value was in error or represented an "unusual event."

Table 6-3-3a: Extraction of Heating and Cooling Loads in NORTHDIY

1. Total Electric	1096 GWh
2. Non-AC Electric 264 X 4	1056 GWh
3. AC Electric [1]-[2]	40 GWh
4. AC Load [3] X 10.36	414 GBtu
5. Bldg. Area	86.58 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	4 800 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	12.2 kWh/ft ²
8. Total Fuel	9810 GBtu
9. Process Heat Fuel 1048 X 4	4192 GBtu
10. Space Heat Fuel [8]-[9]	5618 GBtu
11. Space Heat Load [10] X 0.7	3933 GBtu
12. Space Heat Load/ft ² [11]/[5]	45 400 Btu/ft ²
13. Process Heat Load [9] X 0.7	2934 GBtu
14. Process Heat Load/ft ² [13]/[5]	33 900 Btu/ft ²

Table 6-3-4: Quarterly Breakdowns of Electricity and Fuel Use in SOUTHDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	39	8	31	319	397	6 190	0 35	35 344 1	244 1261 264	2380
3Q	49	9	36	375	469	1 71	0 13	2 222	163 595 192	1259
4Q	64	12	44	392	512	0 55	0 11	1 237	152 491 190	1137
1Q	41	7	32	343	423	1 92	0 24	1 278	132 811 197	1536
Yr.	193	36	143	1429	1801	416	83	1121	4692	6312

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Note: Other fuel in Shore Activity is 76% steam and hot water and 24% coal.

Table 6-3-4a: Extraction of Heating and Cooling Loads in SOUTHDIIV

1. Total Electric	1801 GWh
2. Non-AC Electric 397 X 4	1588 GWh
3. AC Electric [1]-[2]	213 GWh
4. AC Load [3] X 10.36	2207 GBtu
5. Bldg. Area	105.81 X10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	20 900 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	15.0 kWh/ft ²
8. Total Fuel	6312 GBtu
9. Process Heat Fuel 1137 X 4	4548 GBtu
10. Space Heat Fuel [8]-[9]	1764 GBtu
11. Space Heat Load [10] X 0.7	1235 GBtu
12. Space Heat Load/ft ² [11]/[5]	11 700 Btu/ft ²
13. Process Heat Load [9] X 0.7	3184 GBtu
14. Process Heat Load/ft ² [13]/[5]	30 100 Btu/ft ²

Table 6-3-5: Quarterly Breakdowns of Electricity and Fuel Use in WESTDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	44			276	320	53 290 2			258 1193 465	2261
3Q	42			270	312	71 129 2			209 899 300	1610
4Q	47			269	316	70 136 2			261 704 157	1330
1Q	45			275	320	71 167 1			245 1522 318	2324
Yr.	178			1090	1268	994			6531	7525

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Note: Marine Housing and Marine Activity are not represented in this division.

Note: Other fuel in Shore Activity is 92% coal.

Table 6-3-5a: Extraction of Heating and Cooling Loads in WESTDIV

1. Total Electric	1268 GWh
2. Non-AC Electric 312 X 4	1248 GWh
3. AC Electric [1]-[2]	20 GWh
4. AC Load [3] X 10.36	207 GBtu
5. Bldg. Area	106.08 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	2 000 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	11.8 kWh/ft ²
8. Total Fuel	7525 GBtu
9. Process Heat Fuel 1330 X 4	5320 GBtu
10. Space Heat Fuel [8]-[9]	2205 GBtu
11. Space Heat Load [10] X 0.7	1544 GBtu
12. Space Heat Load/ft ² [11]/[5]	14 600 Btu/ft ²
13. Process Heat Load [9] X 0.7	3724 GBtu
14. Process Heat Load/ft ² [13]/[5]	35 100 Btu/ft ²

Table 6-3-6: Quarterly Breakdowns of Electricity and Fuel Use in SWESTDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	19	21	82	146	268	181	199	17 495 115	4 434 316	1761
3Q	18	23	87	151	279	130	98	12 260 45	4 428 278	1255
4Q	19	29	106	157	311	71	61	8 212 41	2 318 139	852
1Q	18	22	86	154	280	100	156	8 381 59	3 308 110	1125
Yr.	74	95	361	608	1138	482	514	1653	2344	4993

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Note: Other fuels in Marine Activity are 75% steam and hot water and 25% propane gas.

Note: Other fuels in Shore Activity are more than 99% steam and hot water.

Table 6-3-6a: Extraction of Heating and Cooling Loads in SWESTDIV

1. Total Electric	1138 GWh
2. Non-AC Electric 268 X 4	1072 GWh
3. AC Electric [1]-[2]	66 GWh
4. AC Load [3] X 10.36	684 GBtu
5. Bldg. Area	114.38 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	6 000 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	9.4 kWh/ft ²
8. Total Fuel	4993 GBtu
9. Process Heat Fuel 852 X 4	3408 GBtu
10. Space Heat Fuel [8]-[9]	1585 GBtu
11. Space Heat Load [10] X 0.7	1110 GBtu
12. Space Heat Load/ft ² [11]/[5]	9 700 Btu/ft ²
13. Process Heat Load [9] X 0.7	2386 GBtu
14. Process Heat Load/ft ² [13]/[5]	20 800 Btu/ft ²

Table 6-3-7: Quarterly Breakdowns of Electricity and Fuel Use in PACDIV

Electricity (GWh)						Fuels (GBtu)				
	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total	Navy Housg.	Marine Housg.	Marine Act'y.	Shore Act'y.	Total
2Q	54	9	63	158	284	253	23	220	643	1167,
						19		1	8	
3Q	61	10	86	155	312	139	9	116	493	785
						18		1	1	8
4Q	72	12	117	178	379	129	5	99	468	725
						16		1	7	
1Q	65	11	77	165	318	165	13	138	467	810
						17		2	1	7
Yr.	252	42	343	656	1293	756	50	578	2103	3487

Note: First line under fuels is fuel oils of all kinds; second line is natural gas; third line is all other fuels.

Table 6-3-7a: Extraction of Heating and Cooling Loads in PACDIV

1. Total Electric	1293 GWh
2. Non-AC Electric 284 X 4	1136 GWh
3. AC Electric [1]-[2]	157 GWh
4. AC Load [3] X 10.36	1627 GBtu
5. Bldg. Area	92.02 X 10 ⁶ ft ²
6. AC Load/ft ² [4]/[5]	17 700 Btu/ft ²
7. Non-AC Electric/ft ² [2]/[5]	12.3 kWh/ft ²
8. Total Fuel	3487 GBtu
9. Process Heat Fuel 725 X 4	2900 GBtu
10. Space Heat Fuel [8]-[9]	587 GBtu
11. Space Heat Load [10] X 0.7	411 GBtu
12. Space Heat Load/ft ² [11]/[5]	4 500 Btu/ft ²
13. Process Heat Load [9] X 0.7	2030 GBtu
14. Process Heat Load/ft ² [13]/[5]	22 000 Btu/ft ²

To evaluate the reasonableness of the numbers obtained in this way, we can do two things. First, we can compare the intensities (loads per square foot) with national-average values. Second, we can see whether the space heating intensities are higher in cold regions than in warm ones, and whether the reverse is true for air conditioning. The table below summarizes the space heating and space cooling intensities for the EFD's, arranged in approximate order from most northerly to most southerly.

	Heating Btu/ft ²	Cooling Btu/ft ² kWh/ft ²	Non-AC Electric Btu/ft ²	Process Heat
NORTHDIV	45 400	4 800	12.2	33 900
WESTDIV	14 600	2 000	11.8	35 100
CHESDIV/LANTDIV	23 800	10 100	15.2	37 800
SWESTDIV	9 700	6 000	9.4	20 800
PACDIV	4 500	17 700	12.3	22 000
SOUTHDIV	11 700	20 900	15.0	30 100
NAVY AVERAGE	18 200	10 200	12.9	30 700
NATIONAL AVG. (COMML. BLDGS.)	28 400	12 400	11.3	13 300

From this table it can be seen that the heating loads are more or less in line with geographical region, with NORTHDIV having the highest and PACDIV (which includes Hawaii and Guam) having the lowest. SOUTHDIV and PACDIV have the highest air-conditioning loads, while NORTHDIV and WESTDIV have the lowest. The Navy appears to have lower heating loads on average than the nation as a whole. (This may be because the Navy's facilities are preferentially located in more southerly locales.) The air-conditioning loads are somewhat lower than the national average also, and this may give cause for concern about the method used. It is plausible, though, that the average Navy facility is not as well air conditioned as the average commercial building.

Non-AC electric use was quite similar in all the EFD's, and the Navy average was not very different from the national average. For process heat, however, the Navy's usage greatly exceeded that of the average commercial building. This should not be surprising, since the Navy must have many uses of energy that would be more akin to industrial than to commercial in the civilian sector. It also helps to explain why the Navy's energy intensity is generally higher than the national average for commercial buildings.

6.4 Loads in the Typical Multibuilding Facility

The next step in the analysis is to relate the loads per square foot developed in the preceding section to the typical multibuilding facility. This was done in the same fashion that Table 5-2 was developed in the preceding analysis for national-average heating, cooling, and electrical loads. These per-square-foot loads, and also the process-heat load, were multiplied by the number of square feet for the whole site (399250), one large building (41520), seven large buildings (290640), and the smaller buildings that composed the rest of the site (108610). Average hourly loads were then obtained by dividing these values by 8760 hours per year. Tables 6-4-1 through 6-4-6 show the results for the EFD's, with CHESDIV and LANTDIV combined. (Hourly loads are expressed in kBtu/h and kW, while annual loads are in Mbtu/h and Mwh, so the divisor is actually 8760/1000 or 8.76.)

The other piece of information necessary for the analysis is the length of the heating, cooling, and shoulder seasons for each EFD. The shoulder season was defined as the number of hours between 60 F and 70 F in a major city located in the EFD's geographical area. For the EFD's along the Atlantic seaboard, this was equal to a nearly uniform 2.5 months. The western EFD's had longer shoulder seasons, ranging from 4 to 5 months. The remainder of the year was then divided between heating and cooling seasons, using weather data as a guide. The lengths of each season used in the analysis for each EFD are shown below the tables.

Table 6-4-1: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in CHESDIV/LANTDIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	9502 MBtu	988 MBtu	6916 MBtu	2586 MBtu
Heating, Hourly	1085 kBtuh	113 kBtuh	789 kBtuh	296 kBtuh
Cooling, Annual	4032 MBtu	419 MBtu	2933 MBtu	1099 MBtu
Cooling, Hourly	460 kBtuh	48 kBtuh	335 kBtuh	125 kBtuh
Non-AC Elec Annual	6069 MWh	631 MWh	4417 MWh	1652 MWh
Non-AC Elec Hourly	693 kW	72 kW	504 kW	189 kW
Proc. Heat Annual	15092 MBtu	1569 MBtu	10983 MBtu	4109 MBtu
Proc. Heat Hourly	1723 kBtuh	179 kBtuh	1254 kBtuh	469 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 2.5 months. Heating Season = 6 months. Cooling Season = 3.5 months.

Table 6-4-2: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in NORTHDIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	18126 MBtu	1885 MBtu	13195 MBtu	4931 MBtu
Heating, Hourly	2069 kBtuh	215 kBtuh	1506 kBtuh	563 kBtuh
Cooling, Annual	1916 MBtu	199 MBtu	1393 MBtu	523 MBtu
Cooling, Hourly	219 kBtuh	23 kBtuh	159 kBtuh	60 kBtuh
Non-AC Elec Annual	4871 MWh	507 MWh	3546 MWh	1325 MWh
Non-AC Elec Hourly	556 kW	58 kW	405 kW	151 kW
Proc. Heat Annual	13535 MBtu	1407 MBtu	9853 MBtu	3682 MBtu
Proc. Heat Hourly	1545 kBtuh	161 kBtuh	1125 kBtuh	420 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 2.5 months. Heating Season = 7 months. Cooling Season = 2.5 months.

Table 6-4-3: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in SOUTH DIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	4671 MBtu	486 MBtu	3400 MBtu	1271 MBtu
Heating, Hourly	533 kBtuh	55 kBtuh	388 kBtuh	145 kBtuh
Cooling, Annual	8344 MBtu	868 MBtu	6074 MBtu	2270 MBtu
Cooling, Hourly	953 kBtuh	99 kBtuh	693 kBtuh	260 kBtuh
Non-AC Elec Annual	5989 MWh	623 MWh	4360 MWh	1629 MWh
Non-AC Elec Hourly	684 kW	71 kW	498 kW	186 kW
Proc. Heat Annual	12017 MBtu	1250 MBtu	8748 MBtu	3269 MBtu
Proc. Heat Hourly	1372 kBtuh	143 kBtuh	999 kBtuh	373 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 2.5 months. Heating Season = 3.5 months. Cooling Season = 6 months.

Table 6-4-4: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in WESTDIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	5829 MBtu	606 MBtu	4213 MBtu	1586 MBtu
Heating, Hourly	665 kBtuh	69 kBtuh	484 kBtuh	181 kBtuh
Cooling, Annual	798 MBtu	83 MBtu	581 MBtu	217 MBtu
Cooling, Hourly	91 kBtuh	9 kBtuh	66 kBtuh	25 kBtuh
Non-AC Elec Annual	4711 MWh	490 MWh	3430 MWh	1281 MWh
Non-AC Elec Hourly	538 kW	56 kW	392 kW	146 kW
Proc. Heat Annual	14014 MBtu	1457 MBtu	10201 MBtu	3813 MBtu
Proc. Heat Hourly	1600 kBtuh	166 kBtuh	1164 kBtuh	435 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 4 months. Heating Season = 6 months. Cooling Season = 2 months.

Table 6-4-5: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in SWSTDIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	3873 MBtu	403 MBtu	2819 MBtu	1054 MBtu
Heating, Hourly	442 kBtuh	46 kBtuh	322 kBtuh	120 kBtuh
Cooling, Annual	2396 MBtu	249 MBtu	1744 MBtu	652 MBtu
Cooling, Hourly	274 kBtuh	28 kBtuh	199 kBtuh	75 kBtuh
Non-AC Elec Annual	3753 MWh	390 MWh	2732 MWh	1021 MWh
Non-AC Elec Hourly	428 kW	45 kW	312 kW	116 kW
Proc. Heat Annual	8304 MBtu	864 MBtu	6045 MBtu	2259 MBtu
Proc. Heat Hourly	948 kBtuh	99 kBtuh	690 kBtuh	258 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 5 months. Heating Season = 5 months. Cooling Season = 2 months.

Table 6-4-6: Annual and Average Hourly Loads for Space Heating, Space Cooling, Electric Power Not Used for Space Cooling, and Process Heat for the Typical Multibuilding Facility in PACDIV.

	Whole Site 399250 ft ²	One Large Building 41520 ft ²	Seven Large Buildings 290640 ft ²	Rest of Site 108610 ft ²
Heating, Annual	1797 MBtu	187 MBtu	1308 MBtu	489 MBtu
Heating, Hourly	205 kBtuh	21 kBtuh	149 kBtuh	56 kBtuh
Cooling, Annual	7067 MBtu	735 MBtu	5144 MBtu	1923 MBtu
Cooling, Hourly	807 kBtuh	84 kBtuh	587 kBtuh	220 kBtuh
Non-AC Elec Annual	4911 MWh	511 MWh	3575 MWh	1336 MWh
Non-AC Elec Hourly	561 kW	58 kW	408 kW	153 kW
Proc. Heat Annual	8784 MBtu	913 MBtu	6394 MBtu	2390 MBtu
Proc. Heat Hourly	1003 kBtuh	104 kBtuh	730 kBtuh	273 kBtuh

Note: MBtu = 10⁶ Btu; Btuh = Btu/h

Shoulder Season = 5 months. Heating Season = 1 month. Cooling Season = 6 months.

6.5 Spreadsheet Input Data

The next step was to prepare inputs to the spreadsheet for each EFD. It was decided to analyze cases with no chillers and with one chiller per cogenerator. In addition, because of the large amount of "process heat" used by the Navy, we wanted to determine the impact of meeting part of this load through cogeneration. The difficulty here is that most process heat in industrial applications is needed at temperatures far too high for cogenerators to supply. We have no direct information on the Navy's situation in this regard. Nevertheless, it seems reasonable to assume that at least a small fraction of this heat could be met by cogeneration. As a benchmark, therefore, we analyzed a hypothetical situation where 20% of the process heat in the cogenerated buildings could be met by cogenerated heat. (This would correspond to about 14% of all process heat, since we are not assuming that heat produced in one building can be transported to another, and therefore none of the process heat in non-cogenerated buildings is accessible to being served by cogeneration.) The four situations analyzed are therefore:

- No chillers, no process heat via cogeneration.
- One chiller per cogenerator, no process heat via cogeneration.
- No chillers, 20% of process heat in cogenerated buildings met by cogeneration.
- One chiller per cogenerator, 20% of process heat in cogenerated buildings met by cogeneration.

In addition, a case with no cogeneration was run on the spreadsheet, as a test to make sure that the numbers agree with the original input data for heat and electricity demands.

The inputs were calculated as follows:

Electricity. The whole-base non-AC electric load was taken from the appropriate table from 3.1 through 3.6, and then the hourly loads for the four steps were computed as 0.5, 1.0, 1.5, and 2.0 times this average load.

Process Heat. For analyses where no process heat is met by cogeneration, the whole-base hourly process heat load was taken from the appropriate table from 3.1 through 3.6 and added to the "RoB heat load" for all heating, cooling, and shoulder cases. Where 20% of the cogenerated-building process heat was to be met by cogenerated heat, 20% of the "7 large buildings" process heat load was added to the "CgB heat load" for all heating, cooling, and shoulder cases, and a like amount was subtracted from the "RoB heat load" amount used in the case immediately above. For example, in CHESDIV/LANTDIV, where no process heat is met by cogeneration, 1723 kBtu/h is added to the "RoB heat load." Where 20% of cogenerated-building process heat is met by cogeneration, 20% of 1254, or 251 kBtu/h is added to the CgB heat load, while 1723-251 or 1472 kBtu/h is added to the RoB heat load, over and above whatever is there because space heating and cooling.

Space Heating. The fraction of the year in the shoulder season is the number of months divided by 12. For the three space heating levels, the fractions of the year are 0.4, 0.4, and 0.2 times the number of months divided by 12. A "low step multiplier" M is calculated in the same way as described in the section on heating and cooling load curves in the preceding analysis. This number, when multiplied by the average hourly heating load, gives the hourly heating load during the lowest heating-load step. The second and third steps are then 2 and 3 times this. If N_h is the number of months in the heating season, and H_{avg} is the average hourly heating load, then in order to have the annual heating load in the analysis equal the actual annual heating load, we must have

$$730 N_h M H_{avg} (0.4 \times 1 + 0.4 \times 2 + 0.2 \times 3) = 8760 H_{avg}$$

which yields

$$M = 6.667 / N_h$$

The cogenerated-building (CgB) and rest-of-buildings (RoB) heat loads for the low, medium, and high heating steps are then calculated by multiplying the average hourly loads for the 7 large buildings and rest of site from the appropriate table from 3.1 - 3.6 by M, 2M, and 3M, respectively, and then adding in any process heat load as described in the preceding section.

Space Cooling. The "low-step multiplier" M is calculated for cooling the same as for heating, but using the number of months in the cooling season. If there are no chillers, the RoB AC electrical load is calculated by multiplying M by the all-base average cooling load from one of the Tables 3.1 - 3.6 and dividing by the average SEER (10.36 Btu/Wh). If there are chillers, then a heat input for the cooling steps is calculated as the lesser of the 7 buildings cooling load and the total chiller capacity. Any excess cooling load is then met electrically as discussed immediately above, with an SEER of 10.36.

Calculations of Inputs. Because the process is somewhat involved, we have summarized the calculations of the actual input data used in the spreadsheets in detail. These calculations, and the spreadsheets themselves, are presented in Appendix B of this report.

6.6 Results of Simulations

The salient energy quantities for each situation analyzed are given in Tables 6-5-1 through 6-5-6. The first thing that leaps from these tables is that much more of the cogenerated heat is used in CHESDIV/LANTDIV, NORTHDIV, and SOUTHDIV than in the more westerly divisions. In NORTHDIV, about half the cogenerated heat is used even without chillers or a process-heat hookup. In CHESDIV/LANTDIV and SOUTHDIV, one has to use chillers and serve process heat in order to achieve similar levels of utilization.

Of course, the primary criterion is not heat utilization but cost savings. The economic analysis in Chapter 7 details the consequences of the various choices for each of the EFD's studied.

6.7 Demand Calculations for Navy EFD's

In addition to deriving energy utilization through the simulation spreadsheets, it is also necessary to derive peak thermal and electrical demands to determine the sizes and types of equipment that must be installed. This was carried out for each EFD, using data from Tables 6-5-1 through 6-5-5, following the methods described in Section 4.15 closely. The lengths of the heating and cooling seasons, given in Table 6-4-1 through 6-4-6, vary significantly between EFD's, and had a strong influence on the peak demands as they were entered into the demand spreadsheets.

Because they are somewhat tedious, the demand spreadsheets are included in Appendix B, after the energy utilization spreadsheets, rather than reproduced here. The resulting demands are used in Chapter 7 as part of the economic evaluation of EFD's.

Table 6-5-1: Annual Energy Quantities for the Typical Multibuilding Facility in CHESDIV/LANTDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used (MBtu)	Heat from Boilers (MBtu)
0	0	6 459	5 585	969	94	24 599	26 224	6 912	17 687
1	0	6 271	5 472	893	94	27 586	25 697	9 899	17 687
0	20%	6 459	5 641	969	150	24 599	26 487	9 102	15 497
1	20%	6 271	5 528	893	150	27 586	25 960	12 089	15 497

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 6459 MWh (all bought) and heat demand is 24599 MBtu (all from boilers).

Table 6-5-2: Annual Energy Quantities for the Typical Multibuilding Facility in NORTHDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used (MBtu)	Heat from Boilers (MBtu)
0	0	5 056	5 410	292	646	31 649	25 405	12 821	18 828
1	0	4 937	5 327	256	646	33 528	25 015	14 710	18 828
0	20%	5 056	5 517	292	753	31 649	25 907	14 554	17 095
1	20%	4 937	5 438	256	757	33 538	25 536	16 443	17 095

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 5056 MWh (all bought) and heat demand is 31649 MBtu (all from boilers).

Table 6-5-3: Annual Energy Quantities for the Typical Multibuilding Facility in SOUTHDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used	Heat from Boilers (MBtu)
0	0	6 797	5 729	1 095	26	16 687	26 899	3 399	13 289
1	0	6 454	5 535	946	26	22 159	25 992	8 870	13 289
2	0	6 265	5 518	870	124	25 178	25 913	11 890	13 289
0	20%	6 797	5 743	1 095	41	16 687	26 969	5 151	11 537
1	20%	6 454	5 550	946	41	22 159	26 062	10 622	11 537
2	20%	6 265	5 578	870	183	25 178	26 193	13 642	11 537

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 6797 MWh (all bought) and heat demand is 16687 MBtu (all from boilers).

Table 6-5-4: Annual Energy Quantities for the Typical Multibuilding Facility in WESTDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used	Heat from Boilers (MBtu)
0	0	4 790	4 595	221	26	19 840	21 578	4 239	15 601
1	0	4 734	4 551	209	26	20 728	21 371	5 128	15 601
0	20%	4 790	4 619	221	50	19 840	21 691	6 280	13 560
1	20%	4 734	4 575	209	50	20 728	21 484	7 169	13 560

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 4790 MWh (all bought) and heat demand is 19840 MBtu (all from boilers).

Table 6-5-5: Annual Energy Quantities for the Typical Multibuilding Facility in SWESTDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used	Heat from Boilers (MBtu)
0	0	3 981	3 957	41	18	12 175	18 581	2 819	9 356
1	0	3 872	3 863	26	18	13 905	18 140	4 550	9 356
0	20%	3 981	3 966	41	26	12 175	18 621	4 028	8 147
1	20%	3 872	3 874	26	28	13 905	18 190	5 759	8 147

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 3981 MWh (all bought) and heat demand is 12175 MBtu (all from boilers).

Table 6-5-6: Annual Energy Quantities for the Typical Multibuilding Facility in PACDIV.

Chil-lers per Cogen.	Process Heat by Cogen.*	Elect. Demnd (MWh)	Elect. Cogen. (MWh)	Elect. Bought (MWh)	Elect. Sold (MWh)	Heat Demnd (MBtu)	Cogen. Heat (MBtu)	Cogen. Heat Used	Heat from Boilers (MBtu)
0	0	5 597	5 192	456	41	10 582	24 334	1 305	9 277
1	0	5 273	4 955	358	41	15 735	23 268	6 458	9 277
2	0	5 123	4 981	313	172	18 118	23 391	8 841	9 277
0	20%	5 597	5 189	456	48	10 582	24 366	2 584	7 998
1	20%	5 273	4 962	358	48	15 735	23 300	7 737	7 998
2	20%	5 123	5 021	313	212	18 118	23 577	10 120	7 998

*Percent of process heat in cogenerated buildings only.

If no cogenerators, electric demand is 5597 MWh (all bought) and heat demand is 10582 MBtu (all from boilers).

7. Economics of Modular Cogeneration in the Navy

7.1 Introduction

In Chapter 6 we analyzed available data on Navy energy use in the seven Engineering Field Divisions (EFD's) and used the results to simulate the operation of modular cogeneration systems installed in our "model facility" with energy demands typical of each EFD. In this chapter we extend the economic analysis of Chapter 5 to these regional studies to project expected economic performance in the different EFD's. We then compare the results of these different studies, and find that the economic performance of modular cogeneration is essentially driven by two factors: the ratio of electric prices to gas prices and the availability of a load to make use of the reject heat.

We did not carry out an economic assessment of the model facility using the characteristics derived in Chapter 6 for PACDIV because of the lack of availability of gas and the extremely diverse entities that were averaged together to derive the statistics.

7.2 CHESDIV/LANTDIV

As discussed in Chapter 6, CHESDIV and LANTDIV are combined into one equivalent EFD with energy-weighted average characteristics. The economic parameters used are shown in the lower left box of Figure 7-1. We were unable to obtain actual rates for electricity purchased by the Navy since they are negotiated by special contract and Navy officials were hesitant to release the terms of the contract without approval. (This also meant that published utility rates would be inaccurate.) We do, however, have the average price paid for electricity, \$0.0568/kWh, an energy-weighted average from Tables 6-2-1 and 6-2-2. The service, energy and demand charges were initially taken to be those of Gulf Power (shown in Figure 7-7, below) but the energy and demand charges were then scaled up so that overall average cost of electricity in the case of boilers and utility electricity came out equal to that average price for CHESDIV and LANTDIV. The result is the rate structure shown. As before and throughout this section, we assume that power sold back to the utility commands a price equal to one-half the average cost of power from the utility. The cost of gas is also an energy-weighted average of the CHESDIV and LANTDIV gas costs shown in Tables 6-2-1 and 6-2-2.

The thermal and electric demands discussed in Section 6.7 and presented in Appendix B are different from the national average and require equipment in somewhat different sizes. The equipment is listed in the upper table in Figure 7-1; the costs have been derived from different entries in the same sources as Table 5-2. Here and in succeeding EFD's the equipment changes are relatively minor.

We do analyze the possibility of meeting some process heat load through cogeneration in the EFD studies, but have included no capital costs for any process heat boilers, since we have no knowledge of what they are, and in any event, they will presumably not change when cogeneration is introduced. Even in the case where 20% of the process heat in the buildings equipped with cogenerators is met by those cogenerators, we take no credit for the removal of

boilers due to the uncertainty in what that credit should be. This results in a very slightly conservative bias in the value derived for modular cogeneration, which we will ignore in our assessments.

In the lower right table in Figure 7-1 the economics for the baseline case, boilers and utility electricity, are displayed. The capital cost are quite similar to the national average figures of Chapter 5, while the annual operating expenses are somewhat higher, due in part to the presence of the process heat load. These capital and operating costs will serve as the baseline against which various modular cogeneration options will be evaluated.

Figure 7-2 presents two economic summary tables, one for modular cogeneration with no absorption chillers and one for the case where each cogenerator has a single absorption chiller attached to it. The economics are not promising in either case. For the "no absorption chiller" case, an investment of \$844k has shifted the bulk of annual outlays from electricity to fuel (gas), but has still resulted in an increase in annual expenses. Adding one absorption chiller makes the situation slightly less bad, but does not turn it around. The incremental capital outlay of \$140k for the absorption units has lowered annual outlays by \$6k, corresponding to a 23 year payback, so even if the cogeneration were being installed for some other reason, the absorption units would be a marginal (although not money-losing) investment. We will compare these results with those from other EFD's at the end of this chapter to attempt to isolate the factors leading to this lack of economic practicality.

Figure 7-3 presents the results for the case where 20% of the process heat consumed in the buildings with cogenerators can be provided by cogenerated thermal energy, as explained in Chapter 6. The situation is similar to the case of no process heat, although not quite as negative.

7.3 NORTHDIV

Figure 7-4 presents the background economic tables for NORTHDIV. Here we use actual electric rates for a large commercial customer of the Philadelphia Electric Company¹. The gas price is the NORTHDIV average from Table 6-2-3. Again the equipment sizes have been adjusted slightly to accommodate the demands calculated for NORTHDIV and presented in Appendix B as discussed in Section 6.7. The resulting economic analysis for boilers and utility electricity is presented in the lower right table of Figure 7-4. Although the average cost of electricity for this scenario came out greater than the average value for NORTHDIV reported in Table 6-2-3, it was decided to use the actual PECO rates rather than to adjust them to give the reported average because many Navy facilities must be paying them and it was thought advisable to use as much "real-world" data as possible.

Figure 7-4 reveals that in this case modular cogeneration is a very promising technology. For the case of no absorption chillers, very large savings pay back the incremental capital in less than three years, offering a very attractive return on investment. However, comparison with the one absorption chiller per cogenerator case indicates that absorption chillers are not a very good investment here,

either, at current prices: the \$142k initial capital investment results in only a \$5k decrement in annual expenses and a thirty year payback. Of course the shorter cooling season contributes to the poor economy of these capital-intensive items.

Figure 7-6 presents the economics for the case where some process heat is served by cogeneration. As might be expected, all the economics improve somewhat, although not strikingly, since the thermal loads were already fairly large. In either case, modular cogeneration is clearly worth in-depth examination in NORTHDIV.

7.4 SOUTHDIV

The background tables for SOUTHDIV are presented in Figure 7-7. Again, actual electric rates for Gulf Power are used²; they assure us that several Naval bases use these "large commercial" rate structures. As before, the equipment costs are broken out above and the economics of boilers and utility electricity summarized in the lower right hand table. The low cost of electric power is balanced by the low cost of gas from Table 6-2-4, and the result is an annual outlay (for the baseline system) which is 36% lower than in NORTHDIV.

Figure 7-8 shows that when fuel and electricity is inexpensive, capital-intensive systems like cogeneration are less attractive. Although the systems are not a loss, they take so long to pay for themselves as to be fairly uninteresting. However, with the long southern cooling system, if the cogeneration system goes in, the absorption chiller is a reasonable option: its incremental cost of \$145k results in an \$11k decrease in operating expenses, corresponding to a 13 year simple payback or a 4.8% return on investment over twenty years.

Figure 7-9 shows that, as for the previously-examined systems, the addition of the process heat loads makes modular cogeneration somewhat more attractive, but not enormously so. Finally, Figure 7-10 shows what happens if we add a second absorption chiller to each cogeneration unit. For both the case with no process heat and that with process heat load being served by cogeneration, the addition of a second absorption chiller, which costs \$152k, actually increases the annual outlay by \$1-2k! The electricity savings are so small that they are outweighed by maintenance on the chillers.

7.5 WESTDIV

The treatment of WESTDIV begins in Figure 7-11. We use electric rates from Pacific Gas and Electric³. Some Navy facilities receive Western Area Power Authority (WAPA) power at considerably lower rates, but many facilities are on the PG&E large commercial schedule, and our results should be taken as applying to them. The very low gas price is the WESTDIV average from Table 6-2-5. Because both heating and cooling loads are low, the equipment requirements are also, and the capital outlay for boilers and compression chillers is much smaller than in the cases already discussed.

Figure 7-12 shows the economics of modular cogeneration for WESTDIV with and without absorption chillers, and here, as in NORTHDIV, the systems are clearly very attractive. Since loads are not large, the high electric rates and low gas price must be the primary influence. Interestingly, the absorption chillers are not completely unreasonable: a \$112k capital investment results in \$7k per year savings, a 17 year payback and a 1.7% return on investment over twenty years. The addition of process heat load in Figure 7-13 produces only marginal improvement in the overall economics.

7.6 SWESTDIV

Finally, the economic background materials for SWESTDIV are presented in Figure 7-14. Relatively expensive electricity is purchased from San Diego Gas and Electric⁴, and gas prices, taken from Table 6-2-6, are considerably higher than for WESTDIV. The boilers are smaller than in WESTDIV, but the chillers are significantly larger, leading to a capital outlay more comparable to the previously studied EFD's than to WESTDIV.

As for WESTDIV, modular cogeneration appears to be an attractive investment in SWESTDIV. With or without absorption chillers or process heat, the simple paybacks are eight to ten years and the returns on investment attractive. Absorption chillers are not so attractive, saving only about \$3k per year for a fifty-year payback.

7.7 Conclusions

The following table summarizes our results in a way that may prove helpful. Of the variables contributing to the value of cogeneration technologies, the prices of gas and electricity and the ability to actually use the cogenerated thermal energy seemed most likely to be relevant. Accordingly, for each EFD we calculated the "electricity-to-gas price ratio" by dividing the overall average cost of electricity (calculated in the "Economics of Boilers and Utility Electricity" tables) by the cost of gas (from the "Economic Parameters" tables) and multiplying the resulting ratio by 293 kWh/MBtu to remove the energy units. Then for each EFD we chose the scenario which was most attractive (had the shortest simple payback period) and calculated the ratio H_{used}/H_{cogen} for that case from the simulation spreadsheet data in Appendix B. (The numbers are in the summary at the bottom of each spreadsheet.) We also recorded the payback time for each case (from the tables in this chapter) and calculated its inverse. The results are presented in Table 7-1:

Quantity: Division	Electricity-to- Gas Price Ratio	$H_{\text{used}}/$ H_{cogen}	Payback Time (years)	Inverse Payback (1/yards)
CHESDIV/ LANTDIV	3.6	47%	176	0.01
NORTHDIV	8.0	56%	2.8	0.36
SOUTHDIV	4.7	41%	42	0.02
WESTDIV	11.3	29%	3.3	0.30
SWESTDIV	5.7	22%	8.3	0.12

Table 7-1: Electricity to fuel price ratios, thermal energy use and payback times for modular cogeneration.

The electricity-to-gas price ratio and the inverse payback time are highly correlated, with $r=0.86$ and $r^2=0.75$. This means that three-fourths of the variation in results among regions is associated with differences in this ratio.

The next most important variable may be the fraction of cogenerated heat that can be utilized. Of the two divisions that gave attractive results, NORTHDIV achieved a 2.8-year payback with a fuel price ratio of about 8, while WESTDIV had a slightly longer payback (3.3 years) despite a fuel price ratio that was 40% higher. The difference is probably due to the fact that in NORTHDIV, with its high heating loads, 56% of the cogenerated heat was utilized, while in WESTDIV only 29% of the heat was used.

In short, it appears that even at current prices, there is a significant value to modular cogeneration in NORTHDIV, WESTDIV and SWESTDIV. As previously discussed, these areas are likely to prove attractive for central cogeneration with district heating and cooling, also, and detailed comparative studies should be carried out at particular sites before conclusions are drawn.

	Equipmen (\$1000's)	Installatio (\$1000's)	Overhead & Profit	---- Cooling Tower -- Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
150 kBtuh	5.3	3.1	1.9			10.3	0.5
500 kBtuh	11.1	6.3	3.5			20.8	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
325 ton AC(1)	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
10 ton	10.1	2.1	2.0	11	2.0	16.2	0.8
20 ton	14.7	2.9	2.9	Inc.		20.5	0.9
30 ton	19.8	3.4	3.9	Inc.		27.1	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0
1) Capacity incremented to cover 20% losses in DHC system.							

Equipment Costs

Electricity Costs:	CHESDIV/LANTDIV Average
Energy:	\$0.0300 /kWh
Demand:	8.75 /kW-mnth
Ratchet:	1 months
Service:	\$227 /month
Purchases	\$0.0284 /kWh
Fuel Cost:	
Gas:	\$0.465 /therm
	= \$4.65 /MBtu
Service:	\$50 /month
Economics:	
Inflation:	Use constant 1995 dollars
Study duration:	20 years

Economic Parameters

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Boilers:				
9 150 kBtuh	92	4.5	15.0	80%
7 500 kBtuh	146	4.2	40.2	80%
Process			87.7	80%
Compression Chillers				
9 8 ton	146	7.2		3.03
7 26 ton	190	7.0		3.03
Electricity				
Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
2.7	170	194	367	0.0568
Totals:				
Capital outlay:	\$574 k			
Annual Outlay:	\$532 k			

Economics for Boilers and Utility Electricity

Figure 7-1: Equipment, Economic Assumptions and Baseline System Costs for CHESDIV/LANTDIV

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	240	38%	Cogenerators: 9 120 kW	990	112	235	38%
Boilers: 9 150 kBtuh & Process	92	5	103	80%	Boilers: 9 150 kBtuh & Process	92	5	103	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 10 ton	146	7		3.03	Compression Chillers 9 10 ton	146	7		3.03
7 30 ton	190	7		3.03	7 30 ton	144	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	47.7	24.0	74.4	0.077	2.7	45.3	21.7	69.8	0.072
- Sales:			(2.7)	(Income)	- Sales:			(2.7)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,418 k			Capital outlay:		\$1,558 k		
Annual Outlay:		545 k			Annual Outlay:		539 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$844 k			Incremental Capital Outlay:		\$984 k		
Annual Savings:		(13) k			Annual Savings:		(6) k		
Simple Payback:		NA years			Simple Payback:		NA years		
Return on Investment:		NA			Return on Investment:		NA		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-2: Economics of Modular Cogeneration, with no process heat, for CHESDIV/LANTDIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	242	38%	Cogenerators: 9 120 kW	990	112	238	38%
Boilers: 9 150 kBtuh & Process	92	5	90	80%	Boilers: 9 150 kBtuh & Process	92	5	90	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 10 ton	146	7		3.03	Compression Chillers: 9 10 ton	146	7		3.03
7 30 ton	190	7		3.03	7 30 ton	144	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	47.7	24.0	74.4	0.077	2.7	45.3	21.7	69.8	0.072
- Sales:			(4.3)	(Income)	- Sales:			(4.3)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,418 k			Capital outlay:		\$1,558 k		
Annual Outlay:		533 k			Annual Outlay:		527 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$844 k			Incremental Capital Outlay:		\$984 k		
Annual Savings:		(1) k			Annual Savings:		6 k		
Simple Payback:		NA years			Simple Payback:		175.8 years		
Return on Investment:		NA			Return on Investment:		NA		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-3: Economics of Modular Cogeneration, with 20% process heat, for CHESDIV/LANTDIV.

	Equipmen (\$1000's)	Installatio (\$1000's)	Overhead & Profit	---- Cooling Tower -- Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
240 kBtuh	5.9	3.4	2.1			11.4	0.5
820 kBtuh	15.4	7.3	4.6			27.3	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
325 ton AC(1):	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
6 ton	6.3	1.3	1.3	11	2.0	10.9	0.8
10 ton	10.1	2.1	2.0	Inc.		14.2	0.9
20 ton	14.7	2.9	2.9	Inc.		20.5	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0
1) Capacity incremented to cover 20% losses in DHC system.							

Equipment Costs

Electricity Costs:	NORTHDIV - PECO
Energy:	\$0.0690 /kWh
Demand:	12.76 /kW-mnth
Ratchet:	1 months
Service:	\$287 /month
Purchases	\$0.0543 /kWh
Fuel Cost:	
Gas:	\$0.397 /therm
=	\$3.97 /MBtu
Service:	\$50 /month
Economics:	
Inflation:	Use constant 1995 dollars
Study duration:	20 years

Economic Parameters

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Boilers:				
9 240 kBtuh	103	4.5	24.5	80%
7 820 kBtuh	191	4.2	65.5	80%
Process			67.1	80%
Compression Chille				
9 6 ton	98	7.2		3.03
7 20 ton	144	7.0		3.03
Electricity				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
3.4	197	349	549	0.1086
Totals:				
Capital outlay:	\$536 k			
Annual Outlay:	\$729 k			

Economics for Boilers and Utility Electricity

Figure 7-4: Equipment, Economic Assumptions and Baseline System Costs for NORTHDIV

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	199	38%	Cogenerators: 9 120 kW	990	112	196	38%
Boilers: 16 240 kBtuh & Process	183	8	93	80%	Boilers: 16 240 kBtuh & Process	183	8	93	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 6 ton	98	7		3.03	Compression Chillers: 9 6 ton	98	7		3.03
7 20 ton	144	7		3.03	7 10 ton	99	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
3.4	23.4	8.5	35.3	0.121	3.4	21.2	6.1	30.7	0.105
- Sales:			(35.1)	(Income)	- Sales:			(35.1)	(Income)
Totals:		Capital outlay: \$1,415 k Annual Outlay: 427 k			Totals:		Capital outlay: \$1,557 k Annual Outlay: 422 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$879 k			Incremental Capital Outlay:		\$1,021 k		
Annual Savings:		302 k			Annual Savings:		307 k		
Simple Payback:		2.9 years			Simple Payback:		3.3 years		
Return on Investment:		34.3%			Return on Investment:		29.9%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-5: Economics of Modular Cogeneration, with no process heat, for NORTHDIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	203	38%	Cogenerators: 9 120 kW	990	112	200	38%
Boilers: 16 240 kBtuh & Process	183	8	85	80%	Boilers: 16 240 kBtuh & Process	183	8	85	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers 9 6 ton	98	7		3.03	Compression Chillers 9 6 ton	98	7		3.03
7 20 ton	144	7		3.03	7 10 ton	99	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
3.4	23.4	8.5	35.3	0.121	3.4	21.2	6.1	30.7	0.105
- Sales:			(40.9)	(Income)	- Sales:			(40.9)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,415 k			Capital outlay:		\$1,557 k		
Annual Outlay:		416 k			Annual Outlay:		411 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$879 k			Incremental Capital Outlay:		\$1,021 k		
Annual Savings:		313 k			Annual Savings:		318 k		
Simple Payback:		2.8 years			Simple Payback:		3.2 years		
Return on Investment:		35.5%			Return on Investment:		31.0%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-6: Economics of Modular Cogeneration, with 20% process heat, for NORTHDIV.

	Equipmen (\$1000's)	Installatio (\$1000's)	Overhead & Profit	---- Cooling Tower -- Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
125 kBtuh	5.0	3.0	1.8			9.9	0.5
425 kBtuh	8.0	4.2	2.4			14.7	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
325 ton AC(1):	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
11 ton	10.1	2.1	2.0	Inc.		14.2	0.8
27 ton	19.1	3.4	3.7	Inc.		26.2	0.9
37 ton	23.7	3.9	4.6	Inc.		32.2	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0
1) Capacity incremented to cover 20% losses in DHC system.							

Equipment Costs

Electricity Costs:	SOUTH DIV - Gulf Power	
Energy:	\$0.0294	/kWh
Demand:	8.57	/kW-mnth
Ratchet:	1	months
Service:	\$227	/month
Purchases	\$0.0274	/kWh
Fuel Cost:		
Gas:	\$0.339	/therm
	=	\$3.39 /MBtu
Service:	\$50	/month
Economics:		
Inflation:	Use constant 1995 dollars	
Study duration:	20 years	

Economic Parameters

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Boilers:				
9 125 kBtuh	89	4.5	5.4	80%
7 425 kBtuh	103	4.2	14.4	80%
Process			50.9	80%
Compression Chillers				
9 11 ton	128	7.2		3.03
7 37 ton	225	7.0		3.03
Electricity				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	169	200	372	0.0547
Totals:				
Capital outlay:	\$545 k			
Annual Outlay:	\$465 k			

Economics for Boilers and Utility Electricity

Figure 7-7: Equipment, Economic Assumptions and Baseline System Costs for SOUTH DIV

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	180	38%	Cogenerators: 9 120 kW	990	112	174	38%
Boilers: 9 125 kBtuh & Process	89	5	56	80%	Boilers: 9 125 kBtuh & Process	89	5	56	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers 9 11 ton	128	7		3.03	Compression Chillers: 9 11 ton	128	7		3.03
7 37 ton	225	7		3.03	7 27 ton	184	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed	Demand	Energy	Total	Average	Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)	(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
2.7	64.1	27.2	94.1	0.086	2.7	60.1	22.9	85.7	0.078
- Sales:			(0.7)	(Income)	- Sales:			(0.7)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,432 k			Capital outlay:		\$1,577 k		
Annual Outlay:		460 k			Annual Outlay:		448 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$887 k			Incremental Capital Outlay:		\$1,032 k		
Annual Savings:		6 k			Annual Savings:		17 k		
Simple Payback:		161.3 years			Simple Payback:		60.8 years		
Return on Investment:		NA			Return on Investment:		NA		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-8: Economics of Modular Cogeneration, with no process heat, for SOUTH DIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	180	38%	Cogenerators: 9 120 kW	990	112	174	38%
Boilers: 9 125 kBtuh & Process	89	5	49	80%	Boilers: 9 125 kBtuh & Process	89	5	49	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 11 ton	128	7		3.03	Compression Chillers: 9 11 ton	128	7		3.03
7 37 ton	225	7		3.03	7 27 ton	184	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
2.7	64.1	27.2	94.1	0.086	2.7	60.1	22.9	85.7	0.078
- Sales:			(1.1)	(Income)	- Sales:			(1.1)	(Income)
Totals:		Capital outlay: \$1,432 k			Totals:		Capital outlay: \$1,577 k		
		Annual Outlay: 453 k					Annual Outlay: 441 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$887 k			Incremental Capital Outlay:		\$1,032 k		
Annual Savings:		13 k			Annual Savings:		24 k		
Simple Payback:		68.7 years			Simple Payback:		42.4 years		
Return on Investment:		NA			Return on Investment:		NA		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-9: Economics of Modular Cogeneration, with process heat, for SOUTH DIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effc.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effc.
Cogenerators: 9 120 kW	990	112	173	38%	Cogenerators: 9 120 kW	990	112	175	38%
Boilers: 9 125 kBtuh & Process	89	5	56	80%	Boilers: 9 125 kBtuh & Process	89	5	49	80%
Absorption Chillers: 14 10 tons	373	7		0.65	Absorption Chillers: 14 10 tons	373	7		0.65
Compression Chillers: 9 6 ton	128	7		3.03	Compression Chillers: 9 11 ton	128	7		3.03
7 16 ton	149	6		3.03	7 16 ton	139	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed	Demand	Energy	Total	Average	Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)	(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
2.7	60.1	20.6	83.5	0.088	2.7	60.1	20.6	83.5	0.088
- Sales:			(0.7)	(Income)	- Sales:			(1.1)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,729 k			Capital outlay:		\$1,719 k		
Annual Outlay:		449 k			Annual Outlay:		443 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$1,185 k			Incremental Capital Outlay:		\$1,175 k		
Annual Savings:		16 k			Annual Savings:		22 k		
Simple Payback:		73.0 years			Simple Payback:		52.8 years		
Return on Investment:		NA			Return on Investment:		NA		

No Process Heat

20% Process Heat

Figure 7-10: Economics of Modular Cogeneration, two absorption chillers per cogen, for SOUTH DIV.

	equipment (\$1000's)	Installation (\$1000's)	Overhead & Profit	---- Cooling Tower -- Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
90 kBtuh	4.3	2.6	1.6			8.5	0.5
310 kBtuh	6.3	3.6	2.0			11.9	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
325 ton AC(1)	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
3.1 ton	3.2	0.7	0.6	Inc.		4.4	0.8
10.1 ton	7.6	1.6	1.5	Inc.		10.7	0.9
10.1 ton	7.6	1.6	1.5	Inc.		10.7	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0

1) Capacity incremented to cover 20% losses in DHC system.

Equipment Costs

Electricity Costs:	WESTDIV - PG&E
Energy:	\$0.0645 /kWh
Demand:	12.72 /kW-mnth
Ratchet:	1 months
Service:	\$310 /month
Purchases	\$0.0523 /kWh
Fuel Cost:	
Gas:	\$0.271 /therm
	= \$2.71 /MBtu
Service:	\$50 /month
Economics:	
Inflation:	Use constant 1995 dollars
Study duration:	20 years

Economic Parameters

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Boilers:				
9 90 kBtuh	77	4.5	5.4	80%
7 310 kBtuh	83	4.2	14.4	80%
Process			47.5	80%
Compression Chillers				
9 3.1 ton	40	7.2		3.03
7 10.1 ton	75	7.0		3.03
Electricity				
Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
3.7	188	309	501	0.1046
Totals:				
Capital outlay:	\$274 k			
Annual Outlay:	\$591 k			

Economics for Boilers and Utility Electricity

Figure 7-11: Equipment, Economic Assumptions and Baseline System Costs for WESTDIV

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	116	38%	Cogenerators: 9 120 kW	990	112	115	38%
Boilers: 9 90 kBtuh & Process	77	5	53	80%	Boilers: 9 90 kBtuh & Process	77	5	53	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 3.1 ton 7 10.1 ton	40 75	7 7		3.03 3.03	Compression Chillers: 9 3.1 ton 0 10.1 ton	40 0	7 0		3.03 3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
3.7	15.6	3.4	22.8	0.103	3.7	14.3	2.6	20.7	0.094
- Sales:			(1.4)	(Income)	- Sales:			(1.4)	(Income)
Totals:		Capital outlay: \$1,181 k Annual Outlay: 321 k			Totals:		Capital outlay: \$1,293 k Annual Outlay: 314 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$907 k			Incremental Capital Outlay:		\$1,019 k		
Annual Savings:		270 k			Annual Savings:		277 k		
Simple Payback:		3.4 years			Simple Payback:		3.7 years		
Return on Investment:		29.6%			Return on Investment:		26.9%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-12: Economics of Modular Cogeneration, with no process heat, for WESTDIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effc.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effc.
Cogenerators: 9 120 kW	990	112	117	38%	Cogenerators: 9 120 kW	990	112	115	38%
Boilers: 9 90 kBtuh & Process	77	5	46	80%	Boilers: 9 90 kBtuh & Process	77	5	46	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers 9 3.1 ton 7 10.1 ton	40 75	7 7		3.03 3.03	Compression Chillers: 9 3.1 ton 0 10.1 ton	40 0	7 0		3.03 3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
3.7	15.6	3.4	22.8	0.103	3.7	14.3	2.6	20.7	0.094
- Sales:			(2.6)	(Income)	- Sales:			(2.6)	(Income)
Totals:		Capital outlay: \$1,181 k Annual Outlay: 313 k			Totals:		Capital outlay: \$1,293 k Annual Outlay: 307 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$907 k			Incremental Capital Outlay:		\$1,019 k		
Annual Savings:		278 k			Annual Savings:		284 k		
Simple Payback:		3.3 years			Simple Payback:		3.6 years		
Return on Investment:		30.4%			Return on Investment:		27.7%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-13: Economics of Modular Cogeneration, with 20% process heat, for WESTDIV.

	Equipment (\$1000's)	Installatio (\$1000's)	Overhead & Profit	---- Cooling Tower -- Capacity (tons)	Cost (\$1000's)	Total Capital	O&M (\$k/year)
Cogenerators:							
120 kW:	105.0			42	5.0	110.0	14.0
775 kW:	470.0			270	15.0	485.0	90.4
Boilers							
75 kBtuh	3.9	2.3	1.4			7.6	0.5
250 kBtuh	7.9	4.5	2.5			14.8	0.6
5000 kBtuh (1)	60.9	28.4	14.9			104.2	2.0
Absorption Chillers							
10 ton AC:	15.8	4.7	4.1	19	2.0	26.7	0.5
325 ton AC(1)	183.2	55.0	47.6	535	68.0	353.8	2.0
Compression AC							
10 ton	9.5	2.0	1.9	Inc.		13.3	0.8
22 ton	16.2	3.2	3.2	Inc.		22.6	0.9
32 ton	21.2	3.7	4.2	Inc.		29.0	1.0
DHC System:							
MaxCapCost:						1515.0	15.0
MinCapCost:						780.0	8.0
1) Capacity incremented to cover 20% losses in DHC system.							

Equipment Costs

Electricity Costs:	SWESTDIV - SDGE
Energy:	\$0.0546 /kWh
Demand:	11.90 /kW-mnth
Ratchet:	1 months
Service:	\$160 /month
Purchases	\$0.0455 /kWh
Fuel Cost:	
Gas:	\$0.470 /therm
	= \$4.70 /MBtu
Service:	\$50 /month
Economics:	
Inflation:	Use constant 1995 dollars
Study duration:	20 years

Economic Parameters

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Boilers:				
9 75 kBtuh	68	4.5	6.2	80%
7 250 kBtuh	104	4.2	16.6	80%
Process			48.8	80%
Compression Chillers				
9 10 ton	120	7.2		3.03
7 32 ton	203	7.0		3.03
Electricity				
Fixed	Demand	Energy	Total	Average
(k\$/year)	(k\$/year)	(k\$/year)	(k\$/year)	(\$/kWh)
1.9	143	217	362	0.0909
Totals:				
Capital outlay:	\$495 k			
Annual Outlay:	\$457 k			

Economics for Boilers and Utility Electricity

Figure 7-14: Equipment, Economic Assumptions and Baseline System Costs for SWESTDIV

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	169	38%	Cogenerators: 9 120 kW	990	112	164	38%
Boilers: 9 75 kBtuh & Process	68	5	55	80%	Boilers: 9 75 kBtuh & Process	68	5	55	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers: 9 10 ton	120	7		3.03	Compression Chillers: 9 10 ton	120	7		3.03
7 32 ton	203	7		3.03	7 22 ton	158	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
1.9	1.4	0.0	3.4	0.082	1.9	0.4	0.0	2.3	0.056
- Sales:			(0.8)	(Income)	- Sales:			(0.8)	(Income)
Totals:		Capital outlay: \$1,381 k Annual Outlay: 357 k			Totals:		Capital outlay: \$1,523 k Annual Outlay: 354 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$886 k			Incremental Capital Outlay:		\$1,028 k		
Annual Savings:		100 k			Annual Savings:		103 k		
Simple Payback:		8.9 years			Simple Payback:		10.0 years		
Return on Investment:		9.4%			Return on Investment:		7.7%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-15: Economics of Modular Cogeneration, with no process heat, for SWESTDIV.

	Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.		Capital (\$k)	Variable (\$k/year)	Fuel (\$k/year)	@ effic.
Cogenerators: 9 120 kW	990	112	169	38%	Cogenerators: 9 120 kW	990	112	165	38%
Boilers: 9 75 kBtuh & Process	68	5	48	80%	Boilers: 9 75 kBtuh & Process	68	5	48	80%
Absorption Chillers: 0 10 tons	0	0		0.65	Absorption Chillers: 7 10 tons	187	4		0.65
Compression Chillers 9 10 ton	120	7		3.03	Compression Chillers: 9 10 ton	120	7		3.03
7 32 ton	203	7		3.03	7 22 ton	158	6		3.03
Electricity - purchases					Electricity - purchases				
Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)	Fixed (k\$/year)	Demand (k\$/year)	Energy (k\$/year)	Total (k\$/year)	Average (\$/kWh)
1.9	1.4	0.0	3.4	0.082	1.9	0.4	0.0	2.3	0.056
- Sales:			(1.2)	(Income)	- Sales:			(1.2)	(Income)
Totals:					Totals:				
Capital outlay:		\$1,381 k			Capital outlay:		\$1,523 k		
Annual Outlay:		350 k			Annual Outlay:		347 k		
Comparison to Boilers & Utility Electricity:					Comparison to Boilers & Utility Electricity:				
Incremental Capital Outlay:		\$886 k			Incremental Capital Outlay:		\$1,028 k		
Annual Savings:		107 k			Annual Savings:		110 k		
Simple Payback:		8.3 years			Simple Payback:		9.4 years		
Return on Investment:		10.4%			Return on Investment:		8.6%		

No Absorption Chillers

One Absorption Chiller per Cogenerator

Figure 7-16: Economics of Modular Cogeneration, with 20% process heat, for SWESTDIV.

References for Chapter 2:

1. L. J. Kostrzewa and K. Davidson, "Packaged Cogeneration", ASHRAE J., Feb. 1988, p. 22.
2. T. Y. Lee and S. deMonsabert, "Users Guide for Small Packaged Cogeneration System (PCS) Applications", TM #: M-73-87-06, Naval Civil Engineering Laboratory, Port Hueneme CA 93043, 1987.
3. Thomas Register of Industrial Companies.
4. H. W. Brown and F. S. Stuber, "Reliability of Natural Gas Cogeneration Systems", Gas Research Institute, 8600 Bryn Mawr Ave, Chicago IL 60631, GRI 93/0020 (1992).
5. Brown & Stuber, op. cit., p. 4-5.
6. C. S. Weaver and S. H. Turner, "Dual Fuel Natural Gas/Diesel Engines: Technology, Performance and Emissions", in *Alternative Fuels in CI and Heavy Duty Engines*, SP-1027, Society of Automotive Engineers, Warrendale PA (1994).
7. D. T. Blizzard, F. S. Schaub and J. G. Smith, "Development of the Cooper-Bessemer CleanBurn Gas-Diesel (Dual-Fuel) Engine", Trans. ASME, Vol 114, p. 480 (July 1992).
8. M. E. Crane and S. R. King, "Emission Reductions Through Precombustion Chamber Design in a natural Gas, Lean Burn Engine", Trans. ASME, Vol 114, p. 466 (July 1992).
9. G. E. Doughty, S. R. Bell and K. C. Midkiff, "Natural Gas Fueling of a Caterpillar 3406 Diesel Engine", J. Engineering for Gas Turbines and Power, Vol 114, p. 459 (July 1992).
10. South Coast Air Quality Management District, *Rule 1110.2 - Emissions From Gaseous and Liquid Fueled Internal Combustion Engines*, 1990.
11. South Coast Air Quality Management District, telephone conversation.
12. Maryland Department of the Environment, telephone conversation.
13. New York State Department of Environmental Conservation, telephone conversation.
14. Texas Natural Resource Conservation Commission, *Technical Guidance Package for Combustion Section Sources - Reciprocating Engines*, March 1995.
15. Texas Natural Resource Conservation Commission, telephone conversation.
16. Commonwealth of Virginia State Air Pollution Control Board, *Regulations For the Control and Abatement of Air Pollution*, January 1992.
17. Commonwealth of Virginia State Air Pollution Control Board, telephone conversation.
18. J. J. White, J. N. Carroll, C. T. Hare and J. G. Lourenco, "Emission Control Strategies for Small Utility Engines", SAE Paper No. 911807
19. Creamer, K. S., and Saunders, J.H. Evaluation of a catalytic converter for a 3.73 kW natural gas engine. Society of Automotive Engineers paper 930221, 1993.

20. Rao, V.D.N., Cikanek, H.A., and Horrocks, R.W. Diesel particulate control system for Ford 1.8L Sierra Turbo-Diesel to meet 1997-2003 particulate standards. Society of Automotive Engineers paper 940458, 1994.
21. Pataky, G.M., Baumgard, K. J., Gratz, L. D., Bagley, S. t., Leddy, D. G., and Johnson, J. H. Effects of an oxidation catalytic converter on regulated and unregulated diesel emissions. Society of Automotive Engineers paper 940243, 1994.
22. Cartellieri, W., Kriegler, W., and Schweinzer, F. Strategies to meet worldwide heavy-duty diesel emission standards. Proc. Instn. Mech. Engrs. 206, 161-171 (1992).
23. Ozturk, S., McKinnon, D.K., Puliafito, J. L., Irigo, B., and Sans, J. International experience using diesel catalytic converters for urban buses. Society of Automotive Engineers paper 940238, 1994.
24. McKinnon, D.L. Seven years experience with diesel particulate filter systems in nonroad applications, Society of Automotive Engineers paper 940234, 1994.
25. P. Zelanka, W. Kriegler, P. L. Herzog and W. P. Cartellieri, "Ways Toward the Clean Heavy Duty Diesel", SAE paper No. 900602, in *Diesel Particulate Emissions*, Johnson, Baines and Clerk, eds., Soc. Automotive Eng., Warrendale PA (1992).
26. S. H. Turner and C. S. Weaver, "Dual-Fuel Natural Gas/Diesel Engines: Technology, Performance and Emissions", GRI-94-0094, Gas Research Institute, Chicago (1994).
27. Brezonie, M. Lowering emissions in mine engines, Diesel Progress 72-73, September 1993.
28. Urban, C. M., Dietzmann, H. E., and Fanick, E.R. Emission control technology for stationary natural gas engines. Journal of Engineering for Gas Turbines and Power, V. 111, pp 369-374, American Society of Mechanical Engineers (July 1989).
29. Weaver, C.S. and McGregor, B. Emission control technology for locomotive engines. Society of Automotive Engineers paper 940453, 1994.
30. Heimrich, M.J. Diesel NO_x catalytic converter development: a review. in Heavy Duty Engines: A Look at the Future, American Society of Mechanical Engineers, ICE-Vol. 22 (1994).
31. Anon. Exhaust after treatment system developed for Caterpillar engines, Diesel and Gas Turbine Worldwide (June 1995).

References for Chapter 3:

1. R. S. Means Co, "Means Mechanical Cost Data", 19th ed., 157-240, Kingston MA 02364-0800 (Oct. 1995).
2. R. S. Means Co., *ibid*, A8.8-130.
3. R. W. Leigh, H. S. Isaacs, J. Kirley and A. Ravve, "Capital Cost Reductions in Absorption Chillers", ASHRAE Transactions 1989, Vol. 95, Pt. 1.
4. ASHRAE 1989 Handbook of Fundamentals (I-P Edition), American Society of Heating, Refrigerating and Air-conditioning Engineers, 1791 Tullie Circle NE, Atlanta GA 30329 (1989)

References for Chapter 4:

1. J. A. Shonder and H. A. McLain, "Energy Savings Potential for Cogeneration in the United States", CADDET Energy Efficiency Newsletter (PO Box 17, 6130 AA, Sittard, The Netherlands) No. 3 (Sept. 1995).
2. U.S. Department Of Energy, Office of Building Technologies "Core Databook", Washington DC (June 1994).

References for Chapter 5

1. U.S. DOE, Office of Building Technologies, op. Cit.
2. U.S. DOE, Office of Building Technologies, op. Cit.
3. C. L. Segaser, "Internal Combustion Engines", Oak Ridge National Laboratory, Oak Ridge TN, ANL/CES/TE 77-1 (1977); C.L.Segaser, "Conventional A-C Generators and Engine Generator Sets", ORNL ANL/CES/TE 78-1 (1978); C.L.Segaser, "Heat Recovery Equipment for Engines", ORNL, ANL/CES/TE 77-4 (1977).
4. U.S. Dept. Of Commerce, Statistical Abstract of the United States - 1994, Table 753, Washington DC (1995), and current updates.
5. J. A. Shonder, private communication
6. R.S.Means Co, Inc., "Means Mechanical Cost Data - 1996", Kingston MA 02364 (1995).
7. R. W. Leigh and M. Piraino, "Increased Use of Reject Heat from Electric Generation", BNL-60174, Brookhaven National Laboratory, Upton NY 11973 (1994).
8. To find the range $A_1 - A_2$, the sum of two ranges $B_1 - B_2$ and $C_1 - C_2$, let $A_{1,2} = A_{ave} \pm \Delta$, where $A_{ave} = (B_1 + B_2)/2 + (C_1 + C_2)/2$ and $\Delta = ((B_2 - B_1)^2 + (C_2 - C_1)^2)^{1/2}/2$. See the previous reference for a detailed explanation.
9. J. A. Shonder and H.A.McClain, op.cit.

References for Chapter 7

1. PECO (Philadelphia Electric Company), Philadelphia PA, rate card supplied by facsimile.
2. Gulf Power Co., Pensacola, telephone conversation.
3. PG&E (Pacific Gas and Electric), San Francisco CA, rate cards supplied by facsimile.
4. San Diego Gas and Electric (SDGE), San Diego CA, rate cards supplied by facsimile.

Appendix A

Cogeneration Simulation Spreadsheets

for

Model Facility

with

National Average Energy Loads

COGEN ELEC. CAP., kW			840		HEAT/ELEC. RATIO, nd		1.375			
frac. of Year Elec. nd			0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW			258		516		774		1032	
SHOULDER										
fY heat, nd	0.166667		258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh	0		0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh	0		258	151	516	226	774	226	840	123
RoB AC Elec Ld, kW	0		1211	707	2423	1061	3634	1061	3944	576
			0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat, nd	0.166667		258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh	1256		1725	1007	1725	756	1725	504	1725	252
RoB Ht Ld, kBtuh	469		267	156	516	226	774	226	840	123
RoB AC Elec Ld, kW	0		1256	734	2423	1061	3634	1061	3944	576
			1256	734	1256	550	1256	367	1256	183
HEATING, MED										
fY heat, nd	0.166667		258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh	2512		3450	2015	3450	1511	3450	1007	3450	504
RoB Ht Ld, kBtuh	938		535	312	535	234	774	226	840	123
RoB AC Elec Ld, kW	0		2512	1467	2512	1100	3634	1061	3944	576
			2512	1467	2512	1100	2512	734	2512	367
HEATING, HIGH										
fY heat, nd	0.083333		258	75	516	113	774	113	1032	75
CgB Ht Ld, kBtuh	3768		5175	1511	5175	1133	5175	756	5175	378
RoB Ht Ld, kBtuh	1407		802	234	802	176	802	117	840	61
RoB AC Elec Ld, kW	0		3768	1100	3768	825	3768	550	3944	288
			3768	1100	3768	825	3768	550	3768	275
COOLING, LOW										
fY heat, nd	0.166667		331	193	589	258	847	247	1105	161
CgB Ht Ld, kBtuh	0		0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh	0		331	193	589	258	840	245	840	123
RoB AC Elec Ld, kW	73		1554	908	2766	1211	3944	1152	3944	576
			0	0	0	0	0	0	0	0
COOLING, MED										
fY heat, nd	0.166667		404	236	662	290	920	269	1178	172
CgB Ht Ld, kBtuh	0		0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh	0		404	236	662	290	840	245	840	123
RoB AC Elec Ld, kW	146		1897	1108	3109	1362	3944	1152	3944	576
			0	0	0	0	0	0	0	0
COOLING, HIGH										
fY heat, nd	0.083333		477	139	735	161	993	145	1251	91
CgB Ht Ld, kBtuh	0		0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh	0		477	139	735	161	840	123	840	61
RoB AC Elec Ld, kW	219		2240	654	3451	756	3944	576	3944	288
			0	0	0	0	0	0	0	0
EACH BLOCK			WHOLE SYSTEM							
Edemand	kW	MWh/yr	5000 MWh/yr				Ebought	264	MWh/yr	
Hdemand	kBtuh	MBtu/yr	11333 MBtu/yr				Esold	401	MWh/yr	
Ecogen	kW	MWh/yr	5137 MWh/yr				Hboilers	3081	MBtu/yr	
Hcogen	kBtuh	MBtu/yr	24123 MBtu/yr							
Hused	kBtuh	MBtu/yr	8252 MBtu/yr							

Cogen Heat Cap., kBtuh

3944.325 BASE CASE, NO CHILLERS

COGEN ELEC. CAP., kW			840		HEAT/ELEC. RATIO, nd		1.375			
frac. of Year Elec. nd			0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW			258		516		774		1032	
SHOULDER										
fY heat, nd 0.166667			258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh 0			0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh 0			258	151	516	226	774	226	840	123
RoB AC Elec Ld, kW 0			1211	707	2423	1061	3634	1061	3944	576
			0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat, nd 0.166667			258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh 1256			1725	1007	1725	756	1725	504	1725	252
RoB Ht Ld, kBtuh 469			267	156	516	226	774	226	840	123
RoB AC Elec Ld, kW 0			1256	734	2423	1061	3634	1061	3944	576
			1256	734	1256	550	1256	367	1256	183
HEATING, MED										
fY heat, nd 0.166667			258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh 2512			3450	2015	3450	1511	3450	1007	3450	504
RoB Ht Ld, kBtuh 938			535	312	535	234	774	226	840	123
RoB AC Elec Ld, kW 0			2512	1467	2512	1100	3634	1061	3944	576
			2512	1467	2512	1100	2512	734	2512	367
HEATING, HIGH										
fY heat, nd 0.083333			258	75	516	113	774	113	1032	75
CgB Ht Ld, kBtuh 3768			5175	1511	5175	1133	5175	756	5175	378
RoB Ht Ld, kBtuh 1407			802	234	802	176	802	117	840	61
RoB AC Elec Ld, kW 0			3768	1100	3768	825	3768	550	3944	288
			3768	1100	3768	825	3768	550	3768	275
COOLING, LOW										
fY heat, nd 0.166667			278	162	536	235	794	232	1052	154
CgB Ht Ld, kBtuh 843			843	492	843	369	843	246	843	123
RoB Ht Ld, kBtuh 0			278	162	536	235	794	232	840	123
RoB AC Elec Ld, kW 20			1305	762	2517	1102	3728	1089	3944	576
			843	492	843	369	843	246	843	123
COOLING, MED										
fY heat, nd 0.166667			323	189	581	254	839	245	1097	160
CgB Ht Ld, kBtuh 1295			1295	756	1295	567	1295	378	1295	189
RoB Ht Ld, kBtuh 0			323	189	581	254	839	245	840	123
RoB AC Elec Ld, kW 65			1517	886	2728	1195	3940	1150	3944	576
			1295	756	1295	567	1295	378	1295	189
COOLING, HIGH										
fY heat, nd 0.083333			395	115	653	143	911	133	1169	85
CgB Ht Ld, kBtuh 1295			1295	378	1295	284	1295	189	1295	95
RoB Ht Ld, kBtuh 0			395	115	653	143	840	123	840	61
RoB AC Elec Ld, kW 137			1855	542	3066	672	3944	576	3944	288
			1295	378	1295	284	1295	189	1295	95
EACH BLOCK			WHOLE SYSTEM							
Edemand	kW	MWh/yr	4744 MWh/yr				Ebought	201 MWh/yr		
Hdemand	kBtuh	MBtu/yr	15400 MBtu/yr				Esold	401 MWh/yr		
Ecogen	kW	MWh/yr	4945 MWh/yr				Hboilers	3081 MBtu/yr		
Hcogen	kBtuh	MBtu/yr	23219 MBtu/yr							
Hused	kBtuh	MBtu/yr	12319 MBtu/yr							

Cogen Heat Cap., kBtuh

3944.325 BASE CASE, 1 CHILLER PER COGEN

COGEN ELEC. CAP., kW			840		HEAT/ELEC. RATIO, nd		1.375			
frac. of Year Elec.	nd		0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW			258		516		774		1032	
SHOULDER										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld,	kBtuh	0	0	0	0	0	0	0	0	0
RoB Ht Ld,	kBtuh	0	258	151	516	226	774	226	840	123
RoB AC Elec Ld,	kW	0	1211	707	2423	1061	3634	1061	3944	576
			0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld,	kBtuh	1256	1725	1007	1725	756	1725	504	1725	252
RoB Ht Ld,	kBtuh	469	267	156	516	226	774	226	840	123
RoB AC Elec Ld,	kW	0	1256	734	2423	1061	3634	1061	3944	576
			1256	734	1256	550	1256	367	1256	183
HEATING, MED										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld,	kBtuh	2512	3450	2015	3450	1511	3450	1007	3450	504
RoB Ht Ld,	kBtuh	938	535	312	535	234	774	226	840	123
RoB AC Elec Ld,	kW	0	2512	1467	2512	1100	3634	1061	3944	576
			2512	1467	2512	1100	2512	734	2512	367
HEATING, HIGH										
fY heat,	nd	0.083333	258	75	516	113	774	113	1032	75
CgB Ht Ld,	kBtuh	3768	5175	1511	5175	1133	5175	756	5175	378
RoB Ht Ld,	kBtuh	1407	802	234	802	176	802	117	840	61
RoB AC Elec Ld,	kW	0	3768	1100	3768	825	3768	550	3944	288
			3768	1100	3768	825	3768	550	3768	275
COOLING, LOW										
fY heat,	nd	0.166667	278	162	536	235	794	232	1052	154
CgB Ht Ld,	kBtuh	843	843	492	843	369	843	246	843	123
RoB Ht Ld,	kBtuh	0	278	162	536	235	794	232	840	123
RoB AC Elec Ld,	kW	20	1305	762	2517	1102	3728	1089	3944	576
			843	492	843	369	843	246	843	123
COOLING, MED										
fY heat,	nd	0.166667	298	174	556	244	814	238	1072	157
CgB Ht Ld,	kBtuh	1686	1686	985	1686	738	1686	492	1686	246
RoB Ht Ld,	kBtuh	0	359	210	556	244	814	238	840	123
RoB AC Elec Ld,	kW	40	1686	985	2611	1144	3822	1116	3944	576
			1686	985	1686	738	1686	492	1686	246
COOLING, HIGH										
fY heat,	nd	0.083333	318	93	576	126	834	122	1092	80
CgB Ht Ld,	kBtuh	2529	2529	738	2529	554	2529	369	2529	185
RoB Ht Ld,	kBtuh	0	539	157	576	126	834	122	840	61
RoB AC Elec Ld,	kW	60	2529	738	2705	592	3916	572	3944	288
			2529	738	2529	554	2529	369	2529	185
EACH BLOCK			WHOLE SYSTEM							
Edemand	kW	MWh/yr	4652 MWh/yr				Ebought	181 MWh/yr		
Hdemand	kBtuh	MBtu/yr	16872 MBtu/yr				Esold	502 MWh/yr		
Ecogen	kW	MWh/yr	4972 MWh/yr				Hboilers	3081 MBtu/yr		
Hcogen	kBtuh	MBtu/yr	23345 MBtu/yr							
Hused	kBtuh	MBtu/yr	13790 MBtu/yr							

Cogen Heat Cap., kBtuh

3944.325 BASE CASE, 2 CHILLERS PER COGEN

COGEN ELEC. CAP., kW			775		HEAT/ELEC. RATIO, nd		1.375			
frac. of Year Elec.	nd		0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW			258		516		774		1032	
SHOULDER										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh		0	0	0	0	0	0	0	0	0
RoB Ht Ld, kBtuh		0	258	151	516	226	774	226	775	113
RoB AC Elec Ld, kW		0	1211	707	2423	1061	3634	1061	3639	531
			0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh		2156	2156	1259	2156	944	2156	630	2156	315
RoB Ht Ld, kBtuh		0	459	268	516	226	774	226	775	113
RoB AC Elec Ld, kW		0	2156	1259	2423	1061	3634	1061	3639	531
			2156	1259	2156	944	2156	630	2156	315
HEATING, MED										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh		4312	4312	2518	4312	1889	4312	1259	4312	630
RoB Ht Ld, kBtuh		0	775	453	775	339	775	226	775	113
RoB AC Elec Ld, kW		0	3639	2125	3639	1594	3639	1063	3639	531
			3639	2125	3639	1594	3639	1063	3639	531
HEATING, HIGH										
fY heat,	nd	0.083333	258	75	516	113	774	113	1032	75
CgB Ht Ld, kBtuh		6468	6468	1889	6468	1417	6468	944	6468	472
RoB Ht Ld, kBtuh		0	775	226	775	170	775	113	775	57
RoB AC Elec Ld, kW		0	3639	1063	3639	797	3639	531	3639	266
			3639	1063	3639	797	3639	531	3639	266
COOLING, LOW										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh		1449	1449	846	1449	635	1449	423	1449	212
RoB Ht Ld, kBtuh		0	309	180	516	226	774	226	775	113
RoB AC Elec Ld, kW		0	1449	846	2423	1061	3634	1061	3639	531
			1449	846	1449	635	1449	423	1449	212
COOLING, MED										
fY heat,	nd	0.166667	258	151	516	226	774	226	1032	151
CgB Ht Ld, kBtuh		2897	2897	1692	2897	1269	2897	846	2897	423
RoB Ht Ld, kBtuh		0	617	360	617	270	774	226	775	113
RoB AC Elec Ld, kW		0	2897	1692	2897	1269	3634	1061	3639	531
			2897	1692	2897	1269	2897	846	2897	423
COOLING, HIGH										
fY heat,	nd	0.083333	258	75	516	113	774	113	1032	75
CgB Ht Ld, kBtuh		4346	4346	1269	4346	952	4346	635	4346	317
RoB Ht Ld, kBtuh		0	775	226	775	170	775	113	775	57
RoB AC Elec Ld, kW		0	3639	1063	3639	797	3639	531	3639	266
			3639	1063	3639	797	3639	531	3639	266
EACH BLOCK			WHOLE SYSTEM							
Edemand	kW	MWh/yr	4520 MWh/yr				Ebought	225 MWh/yr		
Hdemand	kBtuh	MBtu/yr	23684 MBtu/yr				Esold	1232 MWh/yr		
Ecogen	kW	MWh/yr	5527 MWh/yr				Hboilers	3564 MBtu/yr		
Hcogen	kBtuh	MBtu/yr	25954 MBtu/yr							
Hused	kBtuh	MBtu/yr	20119 MBtu/yr							

Cogen Heat Cap., kBtuh

3639 BASE CASE, DHC COGEN & ABS. CHILLER

Appendix B

Cogeneration Simulation Spreadsheets

for

Model Facility

with

Navy EFD - Specific Energy Loads

Appendix B: Input Data and Spreadsheet Analyses for Navy EFD's

CHESDIV/LANTDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 693 kW

Low step = 0.5 X above = 346 kW

2nd step = 1.0 X above = 693 kW

3rd step = 1.5 X above = 1040 kW

4th step = 2.0 X above = 1386 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

1723 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 1254 kBtuh = 251 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 2.5

HEATING SEASON: Months in season = 6.0

Low step multiplier = 6.667/months in season = 1.111

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.208	0	0	0
Low	0.200	877	329	0
Medium	0.200	1753	658	0
High	0.100	2630	987	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

CHESDIV/LANTDIV SPREADSHEET INPUTS

COOLING: Months in season = 3.5

Low step multiplier = 6.667/months in season = 1.905

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.117	460	X 1.905	X 1/10.36	= 85
Med	0.117	460	X 1.905	X 2/10.36	= 169
High	0.058	460	X 1.905	X 3/10.36	= 254

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	638	238	638	982	238	23
Med	1276	476	840	1292	912	88
High	1915	714	840	1292	1789	173

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

COGEN ELEC. CAP., kW		0	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		346	693			1040		1386		
SHOULDER										
fY heat,	nd	0.208	346	252	693	379	1040	379	1386	253
CgB Ht Ld, kBtuh	0	1723	1256	1723	942	1723	628	1723	314	
RoB Ht Ld, kBtuh	1723	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	877	2929	2053	2929	1539	2929	1026	2929	513	
RoB Ht Ld, kBtuh	2052	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, MED										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	1753	4134	2897	4134	2173	4134	1449	4134	724	
RoB Ht Ld, kBtuh	2381	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, HIGH										
fY heat,	nd	0.1	346	121	693	182	1040	182	1386	121
CgB Ht Ld, kBtuh	2630	5340	1871	5340	1403	5340	936	5340	468	
RoB Ht Ld, kBtuh	2710	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, LOW										
fY heat,	nd	0.117	431	177	778	239	1125	231	1471	151
CgB Ht Ld, kBtuh	0	1723	706	1723	530	1723	353	1723	177	
RoB Ht Ld, kBtuh	1723	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	85	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, MED										
fY heat,	nd	0.117	515	211	862	265	1209	248	1555	159
CgB Ht Ld, kBtuh	0	1723	706	1723	530	1723	353	1723	177	
RoB Ht Ld, kBtuh	1723	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	169	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, HIGH										
fY heat,	nd	0.058	600	122	947	144	1294	131	1640	83
CgB Ht Ld, kBtuh	0	1723	350	1723	263	1723	175	1723	88	
RoB Ht Ld, kBtuh	1723	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	254	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	6459			Ebought MWh/yr	6459				
Hdemand kBtuh	MBtu/yr	24599			Esold MWh/yr	0				
Ecogen kW	MWh/yr	0			Hboilers MBtu/yr	24599				
Hcogen kBtuh	MBtu/yr	0								
Hused kBtuh	MBtu/yr	0								

Cogen Heat Cap., kBtuh 0 CHESDIV/LANTDIV, NO COGEN

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		346		693		1040		1386	
SHOULDER									
fY heat,	nd	0.208	346	252	693	379	1040	379	1386
CgB Ht Ld, kBtuh	0	1723	1256	1723	942	1723	628	1723	
RoB Ht Ld, kBtuh	1723	346	252	693	379	840	306	840	
RoB AC Elec Ld, kW	0	1625	1184	3254	1779	3944	1437	3944	
		0	0	0	0	0	0	0	
HEATING, LOW									
fY heat,	nd	0.2	346	242	693	364	1040	364	1386
CgB Ht Ld, kBtuh	877	2929	2053	2929	1539	2929	1026	2929	
RoB Ht Ld, kBtuh	2052	346	242	693	364	840	294	840	
RoB AC Elec Ld, kW	0	1625	1139	3254	1710	3944	1382	3944	
		877	615	877	461	877	307	877	
HEATING, MED									
fY heat,	nd	0.2	346	242	693	364	1040	364	1386
CgB Ht Ld, kBtuh	1753	4134	2897	4134	2173	4134	1449	4134	
RoB Ht Ld, kBtuh	2381	373	262	693	364	840	294	840	
RoB AC Elec Ld, kW	0	1753	1229	3254	1710	3944	1382	3944	
		1753	1229	1753	921	1753	614	1753	
HEATING, HIGH									
fY heat,	nd	0.1	346	121	693	182	1040	182	1386
CgB Ht Ld, kBtuh	2630	5340	1871	5340	1403	5340	936	5340	
RoB Ht Ld, kBtuh	2710	560	196	693	182	840	147	840	
RoB AC Elec Ld, kW	0	2630	922	3254	855	3944	691	3944	
		2630	922	2630	691	2630	461	2630	
COOLING, LOW									
fY heat,	nd	0.117	431	177	778	239	1125	231	1471
CgB Ht Ld, kBtuh	0	1723	706	1723	530	1723	353	1723	
RoB Ht Ld, kBtuh	1723	431	177	778	239	840	172	840	
RoB AC Elec Ld, kW	85	2024	830	3653	1123	3944	809	3944	
		0	0	0	0	0	0	0	
COOLING, MED									
fY heat,	nd	0.117	515	211	862	265	1209	248	1555
CgB Ht Ld, kBtuh	0	1723	706	1723	530	1723	353	1723	
RoB Ht Ld, kBtuh	1723	515	211	840	258	840	172	840	
RoB AC Elec Ld, kW	169	2418	991	3944	1213	3944	809	3944	
		0	0	0	0	0	0	0	
COOLING, HIGH									
fY heat,	nd	0.058	600	122	947	144	1294	131	1640
CgB Ht Ld, kBtuh	0	1723	350	1723	263	1723	175	1723	
RoB Ht Ld, kBtuh	1723	600	122	840	128	840	85	840	
RoB AC Elec Ld, kW	254	2817	573	3944	601	3944	401	3944	
		0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr	6459			Ebought	MWh/yr	969		
Hdemand kBtuh	MBtu/yr	24599			Esold	MWh/yr	94		
Ecogen kW	MWh/yr	5585			Hboilers	MBtu/yr	17687		
Hcogen kBtuh	MBtu/yr	26224							
Hused kBtuh	MBtu/yr	6912							

Cogen Heat Cap., kBtuh 3944.325 CHESDIV/LANTDIV, NO CHILLERS, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2			0.1		
All Base nonAC Elec Ld, kW		346	693		1040			1386		
SHOULDER										
fY heat,	nd	0.208	346	252	693	379	1040	379	1386	253
CgB Ht Ld, kBtuh	0	1723	1256	1723	942	1723	628	1723	314	
RoB Ht Ld, kBtuh	1723	346	252	693	379	840	306	840	153	
RoB AC Elec Ld, kW	0	1625	1184	3254	1779	3944	1437	3944	719	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	877	2929	2053	2929	1539	2929	1026	2929	513	
RoB Ht Ld, kBtuh	2052	346	242	693	364	840	294	840	147	
RoB AC Elec Ld, kW	0	1625	1139	3254	1710	3944	1382	3944	691	
		877	615	877	461	877	307	877	154	
HEATING, MED										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	1753	4134	2897	4134	2173	4134	1449	4134	724	
RoB Ht Ld, kBtuh	2381	373	262	693	364	840	294	840	147	
RoB AC Elec Ld, kW	0	1753	1229	3254	1710	3944	1382	3944	691	
		1753	1229	1753	921	1753	614	1753	307	
HEATING, HIGH										
fY heat,	nd	0.1	346	121	693	182	1040	182	1386	121
CgB Ht Ld, kBtuh	2630	5340	1871	5340	1403	5340	936	5340	468	
RoB Ht Ld, kBtuh	2710	560	196	693	182	840	147	840	74	
RoB AC Elec Ld, kW	0	2630	922	3254	855	3944	691	3944	346	
		2630	922	2630	691	2630	461	2630	230	
COOLING, LOW										
fY heat,	nd	0.117	369	151	716	220	1063	218	1409	144
CgB Ht Ld, kBtuh	982	2705	1109	2705	832	2705	554	2705	277	
RoB Ht Ld, kBtuh	1723	369	151	716	220	840	172	840	86	
RoB AC Elec Ld, kW	23	1733	710	3362	1034	3944	809	3944	404	
		982	403	982	302	982	201	982	101	
COOLING, MED										
fY heat,	nd	0.117	434	178	781	240	1128	231	1474	151
CgB Ht Ld, kBtuh	1292	3015	1236	3015	927	3015	618	3015	309	
RoB Ht Ld, kBtuh	1723	434	178	781	240	840	172	840	86	
RoB AC Elec Ld, kW	88	2038	835	3667	1128	3944	809	3944	404	
		1292	530	1292	397	1292	265	1292	132	
COOLING, HIGH										
fY heat,	nd	0.058	519	105	866	132	1213	123	1559	79
CgB Ht Ld, kBtuh	1292	3015	613	3015	460	3015	306	3015	153	
RoB Ht Ld, kBtuh	1723	519	105	840	128	840	85	840	43	
RoB AC Elec Ld, kW	173	2437	495	3944	601	3944	401	3944	200	
		1292	263	1292	197	1292	131	1292	66	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	6271		Ebought	MWh/yr	893			
Hdemand	kBtuh	MBtu/yr	27586		Esold	MWh/yr	94			
Ecogen	kW	MWh/yr	5472		Hboilers	MBtu/yr	17687			
Hcogen	kBtuh	MBtu/yr	25697							
Hused	kBtuh	MBtu/yr	9899							

Cogen Heat Cap., kBtuh 3944.325 CHESDIV/LANTDIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		346		693		1040		1386	
SHOULDER									
fY heat,	nd	0.208	346	252	693	379	1040	379	1386
CgB Ht Ld, kBtuh	250	1723	1256	1723	942	1723	628	1723	314
RoB Ht Ld, kBtuh	1473	346	252	693	379	840	306	840	153
RoB AC Elec Ld, kW	0	1625	1184	3254	1779	3944	1437	3944	719
		250	182	250	137	250	91	250	46
HEATING, LOW									
fY heat,	nd	0.2	346	242	693	364	1040	364	1386
CgB Ht Ld, kBtuh	1127	2929	2053	2929	1539	2929	1026	2929	513
RoB Ht Ld, kBtuh	1802	346	242	693	364	840	294	840	147
RoB AC Elec Ld, kW	0	1625	1139	3254	1710	3944	1382	3944	691
		1127	790	1127	592	1127	395	1127	197
HEATING, MED									
fY heat,	nd	0.2	346	242	693	364	1040	364	1386
CgB Ht Ld, kBtuh	2003	4134	2897	4134	2173	4134	1449	4134	724
RoB Ht Ld, kBtuh	2131	427	299	693	364	840	294	840	147
RoB AC Elec Ld, kW	0	2003	1404	3254	1710	3944	1382	3944	691
		2003	1404	2003	1053	2003	702	2003	351
HEATING, HIGH									
fY heat,	nd	0.1	346	121	693	182	1040	182	1386
CgB Ht Ld, kBtuh	2880	5340	1871	5340	1403	5340	936	5340	468
RoB Ht Ld, kBtuh	2460	613	215	693	182	840	147	840	74
RoB AC Elec Ld, kW	0	2880	1009	3254	855	3944	691	3944	346
		2880	1009	2880	757	2880	505	2880	252
COOLING, LOW									
fY heat,	nd	0.117	431	177	778	239	1125	231	1471
CgB Ht Ld, kBtuh	250	1723	706	1723	530	1723	353	1723	177
RoB Ht Ld, kBtuh	1473	431	177	778	239	840	172	840	86
RoB AC Elec Ld, kW	85	2024	830	3653	1123	3944	809	3944	404
		250	102	250	77	250	51	250	26
COOLING, MED									
fY heat,	nd	0.117	515	211	862	265	1209	248	1555
CgB Ht Ld, kBtuh	250	1723	706	1723	530	1723	353	1723	177
RoB Ht Ld, kBtuh	1473	515	211	840	258	840	172	840	86
RoB AC Elec Ld, kW	169	2418	991	3944	1213	3944	809	3944	404
		250	102	250	77	250	51	250	26
COOLING, HIGH									
fY heat,	nd	0.058	600	122	947	144	1294	131	1640
CgB Ht Ld, kBtuh	250	1723	350	1723	263	1723	175	1723	88
RoB Ht Ld, kBtuh	1473	600	122	840	128	840	85	840	43
RoB AC Elec Ld, kW	254	2817	573	3944	601	3944	401	3944	200
		250	51	250	38	250	25	250	13
EACH BLOCK		WHOLE SYSTEM							
Edemand	kW	MWh/yr	6459		Ebought	MWh/yr	969		
Hdemand	kBtuh	MBtu/yr	24599		Esold	MWh/yr	150		
Ecogen	kW	MWh/yr	5641		Hboilers	MBtu/yr	15497		
Hcogen	kBtuh	MBtu/yr	26487						
Hused	kBtuh	MBtu/yr	9102						

Cogen Heat Cap., kBtuh 3944.325 CHESDIV/LANTDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		346	693			1040		1386		
SHOULDER										
fY heat,	nd	0.208	346	252	693	379	1040	379	1386	253
CgB Ht Ld, kBtuh	250	1723	1256	1723	942	1723	628	1723	314	
RoB Ht Ld, kBtuh	1473	346	252	693	379	840	306	840	153	
RoB AC Elec Ld, kW	0	1625	1184	3254	1779	3944	1437	3944	719	
		250	182	250	137	250	91	250	46	
HEATING, LOW										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	1127	2929	2053	2929	1539	2929	1026	2929	513	
RoB Ht Ld, kBtuh	1802	346	242	693	364	840	294	840	147	
RoB AC Elec Ld, kW	0	1625	1139	3254	1710	3944	1382	3944	691	
		1127	790	1127	592	1127	395	1127	197	
HEATING, MED										
fY heat,	nd	0.2	346	242	693	364	1040	364	1386	243
CgB Ht Ld, kBtuh	2003	4134	2897	4134	2173	4134	1449	4134	724	
RoB Ht Ld, kBtuh	2131	427	299	693	364	840	294	840	147	
RoB AC Elec Ld, kW	0	2003	1404	3254	1710	3944	1382	3944	691	
		2003	1404	2003	1053	2003	702	2003	351	
HEATING, HIGH										
fY heat,	nd	0.1	346	121	693	182	1040	182	1386	121
CgB Ht Ld, kBtuh	2880	5340	1871	5340	1403	5340	936	5340	468	
RoB Ht Ld, kBtuh	2460	613	215	693	182	840	147	840	74	
RoB AC Elec Ld, kW	0	2880	1009	3254	855	3944	691	3944	346	
		2880	1009	2880	757	2880	505	2880	252	
COOLING, LOW										
fY heat,	nd	0.117	369	151	716	220	1063	218	1409	144
CgB Ht Ld, kBtuh	1232	2705	1109	2705	832	2705	554	2705	277	
RoB Ht Ld, kBtuh	1473	369	151	716	220	840	172	840	86	
RoB AC Elec Ld, kW	23	1733	710	3362	1034	3944	809	3944	404	
		1232	505	1232	379	1232	253	1232	126	
COOLING, MED										
fY heat,	nd	0.117	434	178	781	240	1128	231	1474	151
CgB Ht Ld, kBtuh	1542	3015	1236	3015	927	3015	618	3015	309	
RoB Ht Ld, kBtuh	1473	434	178	781	240	840	172	840	86	
RoB AC Elec Ld, kW	88	2038	835	3667	1128	3944	809	3944	404	
		1542	632	1542	474	1542	316	1542	158	
COOLING, HIGH										
fY heat,	nd	0.058	519	105	866	132	1213	123	1559	79
CgB Ht Ld, kBtuh	1542	3015	613	3015	460	3015	306	3015	153	
RoB Ht Ld, kBtuh	1473	519	105	840	128	840	85	840	43	
RoB AC Elec Ld, kW	173	2437	495	3944	601	3944	401	3944	200	
		1542	313	1542	235	1542	157	1542	78	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	6271			Ebought	MWh/yr	893			
Hdemand kBtuh	MBtu/yr	27586			Esold	MWh/yr	150			
Ecogen kW	MWh/yr	5528			Hboilers	MBtu/yr	15497			
Hcogen kBtuh	MBtu/yr	25960								
Hused kBtuh	MBtu/yr	12089								

Cogen Heat Cap., kBtuh 3944.325 CHESDIV/LANTDIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

# of Buildings:	Large Building 7	Small Building 9	Total for Site (1)	Units	Number of 10 ton Absorption Chillers per cogen unit	
Heating Demand:	Diversity	Factor =	50%			
6 Month Season						
Annual Energy:	988	287	9502	MBtu		
Annual Peak:	501	146	4281	kBtuh		
Cooling Demand:	Diversity	Factor =	50%			
3.5 Month Season						
Annual Energy:	419	122	4032	MBtu		
Annual Peak:	364	106	3114	kBtuh		
Capacity	30.4	8.9	260	tons with	0	
Requirement	20.4	8.9	na	tons	1	
	10.4	8.9	na	tons	2	
	0.4	8.9	na	tons	3	
Electric Demand with EER		10.36 Btu/Wh,		DF= 50%		
There are	1.4	1.4	1.4	0.7	months	
when P(AC)=	46.7	131.3	216.0	300.6	0	
(in kW)	46.7	53.6	138.2	222.8	1	
	46.7	46.7	60.4	145.0	2	
	46.7	46.7	46.7	67.3	3	
Non-AC Electric:	Large	Small	Total	DF= 50%		
Annual Energy	631	184	6069	MWh		
Peak Demand:	180	52	1577	kW for	7.1 months	
Total Electric Demand					DF= 0%	
There are	1.4	1.4	1.4	0.7	months	
when P(tot)=	1577	1661	1746	1831	0	
(in kW)	1577	1584	1668	1753	1	
	1577	1577	1591	1675	2	
	1577	1577	1577	1597	3	
Utility Demand with	9	120	kW cogenerators:			
There are	1.4	1.4	1.4	0.7	months	
when P(tot)=	497	581	666	751	0	and
(in kW)	497	504	588	673	1	5
	497	497	511	595	2	with
	497	497	497	517	3	497
1 See discussion of diversity in text.						

Demand Table - CHESDIV/LANTDIV

NORTHDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 556 kW

Low step = 0.5 X above = 278 kW

2nd step = 1.0 X above = 556 kW

3rd step = 1.5 X above = 834 kW

4th step = 2.0 X above = 1112 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

1545 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 1125 kBtuh = 225 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 2.5

HEATING SEASON: Months in season = 7.0

Low step multiplier = 6.667/months in season = 0.952

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.209	0	0	0
Low	0.233	1434	535	0
Medium	0.233	2867	1072	0
High	0.117	4301	1608	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

NORTHDIV SPREADSHEET INPUTS

COOLING: Months in season = 2.5

Low step multiplier = 6.667/months in season = 2.667

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.083	219	X 2.667	X 1/10.36	= 56
Med	0.083	219	X 2.667	X 2/10.36	= 113
High	0.042	219	X 2.667	X 3/10.36	= 169

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	424	160	424	652	160	15
Med	848	320	840	1292	328	32
High	1272	480	840	1292	912	88

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

COGEN ELEC. CAP., kW		0	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1		
All Base nonAC Elec Ld, kW		278		556		834		1112		
SHOULDER										
fY heat,	nd	0.209	278	204	556	305	834	305	1112	204
CgB Ht Ld, kBtuh	0	1545	1131	1545	849	1545	566	1545	283	
RoB Ht Ld, kBtuh	1545	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	1434	3514	2869	3514	2152	3514	1434	3514	717	
RoB Ht Ld, kBtuh	2080	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, MED										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	2867	5484	4477	5484	3358	5484	2239	5484	1119	
RoB Ht Ld, kBtuh	2617	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
HEATING, HIGH										
fY heat,	nd	0.117	278	114	556	171	834	171	1112	114
CgB Ht Ld, kBtuh	4301	7454	3056	7454	2292	7454	1528	7454	764	
RoB Ht Ld, kBtuh	3153	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, LOW										
fY heat,	nd	0.083	334	97	612	133	890	129	1168	85
CgB Ht Ld, kBtuh	0	1545	449	1545	337	1545	225	1545	112	
RoB Ht Ld, kBtuh	1545	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	56	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, MED										
fY heat,	nd	0.083	391	114	669	146	947	138	1225	89
CgB Ht Ld, kBtuh	0	1545	449	1545	337	1545	225	1545	112	
RoB Ht Ld, kBtuh	1545	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	113	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
COOLING, HIGH										
fY heat,	nd	0.042	447	66	725	80	1003	74	1281	47
CgB Ht Ld, kBtuh	0	1545	227	1545	171	1545	114	1545	57	
RoB Ht Ld, kBtuh	1545	0	0	0	0	0	0	0	0	
RoB AC Elec Ld, kW	169	0	0	0	0	0	0	0	0	
		0	0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	5056			Ebought	MWh/yr	5056		
Hdemand	kBtuh	MBtu/yr	31649			Esold	MWh/yr	0		
Ecogen	kW	MWh/yr	0			Hboilers	MBtu/yr	31649		
Hcogen	kBtuh	MBtu/yr	0							
Hused	kBtuh	MBtu/yr	0							

Cogen Heat Cap., kBtuh 0 NORTHDIV, NO COGEN

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		278	556			834		1112		
SHOULDER										
fY heat,	nd	0.209	278	204	556	305	834	305	1112	204
CgB Ht Ld, kBtuh	0	1545	1131	1545	849	1545	566	1545	283	
RoB Ht Ld, kBtuh	1545	278	204	556	305	834	305	840	154	
RoB AC Elec Ld, kW	0	1305	956	2611	1434	3916	1434	3944	722	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	1434	3514	2869	3514	2152	3514	1434	3514	717	
RoB Ht Ld, kBtuh	2080	305	249	556	340	834	340	840	171	
RoB AC Elec Ld, kW	0	1434	1171	2611	1599	3916	1599	3944	805	
		1434	1171	1434	878	1434	585	1434	293	
HEATING, MED										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	2867	5484	4477	5484	3358	5484	2239	5484	1119	
RoB Ht Ld, kBtuh	2617	611	498	611	374	834	340	840	171	
RoB AC Elec Ld, kW	0	2867	2341	2867	1756	3916	1599	3944	805	
		2867	2341	2867	1756	2867	1170	2867	585	
HEATING, HIGH										
fY heat,	nd	0.117	278	114	556	171	834	171	1112	114
CgB Ht Ld, kBtuh	4301	7454	3056	7454	2292	7454	1528	7454	764	
RoB Ht Ld, kBtuh	3153	840	344	840	258	840	172	840	86	
RoB AC Elec Ld, kW	0	3944	1617	3944	1213	3944	809	3944	404	
		3944	1617	3944	1213	3944	809	3944	404	
COOLING, LOW										
fY heat,	nd	0.083	334	97	612	133	890	129	1168	85
CgB Ht Ld, kBtuh	0	1545	449	1545	337	1545	225	1545	112	
RoB Ht Ld, kBtuh	1545	334	97	612	133	840	122	840	61	
RoB AC Elec Ld, kW	56	1568	456	2874	627	3944	574	3944	287	
		0	0	0	0	0	0	0	0	
COOLING, MED										
fY heat,	nd	0.083	391	114	669	146	947	138	1225	89
CgB Ht Ld, kBtuh	0	1545	449	1545	337	1545	225	1545	112	
RoB Ht Ld, kBtuh	1545	391	114	669	146	840	122	840	61	
RoB AC Elec Ld, kW	113	1836	534	3141	685	3944	574	3944	287	
		0	0	0	0	0	0	0	0	
COOLING, HIGH										
fY heat,	nd	0.042	447	66	725	80	1003	74	1281	47
CgB Ht Ld, kBtuh	0	1545	227	1545	171	1545	114	1545	57	
RoB Ht Ld, kBtuh	1545	447	66	725	80	840	62	840	31	
RoB AC Elec Ld, kW	169	2099	309	3404	376	3944	290	3944	145	
		0	0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	5056			Ebought	MWh/yr	292		
Hdemand	kBtuh	MBtu/yr	31649			Esold	MWh/yr	646		
Ecogen	kW	MWh/yr	5410			Hboilers	MBtu/yr	18828		
Hcogen	kBtuh	MBtu/yr	25405							
Hused	kBtuh	MBtu/yr	12821							

Cogen Heat Cap., kBtuh 3944.325 NORTHDIV, NO CHILLERS, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2			0.1		
All Base nonAC Elec Ld, kW		278	556		834			1112		
SHOULDER										
fY heat,	nd	0.209	278	204	556	305	834	305	1112	204
CgB Ht Ld, kBtuh	0	1545	1131	1545	849	1545	566	1545	283	
RoB Ht Ld, kBtuh	1545	278	204	556	305	834	305	840	154	
RoB AC Elec Ld, kW	0	1305	956	2611	1434	3916	1434	3944	722	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	1434	3514	2869	3514	2152	3514	1434	3514	717	
RoB Ht Ld, kBtuh	2080	305	249	556	340	834	340	840	171	
RoB AC Elec Ld, kW	0	1434	1171	2611	1599	3916	1599	3944	805	
		1434	1171	1434	878	1434	585	1434	293	
HEATING, MED										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	2867	5484	4477	5484	3358	5484	2239	5484	1119	
RoB Ht Ld, kBtuh	2617	611	498	611	374	834	340	840	171	
RoB AC Elec Ld, kW	0	2867	2341	2867	1756	3916	1599	3944	805	
		2867	2341	2867	1756	2867	1170	2867	585	
HEATING, HIGH										
fY heat,	nd	0.117	278	114	556	171	834	171	1112	114
CgB Ht Ld, kBtuh	4301	7454	3056	7454	2292	7454	1528	7454	764	
RoB Ht Ld, kBtuh	3153	840	344	840	258	840	172	840	86	
RoB AC Elec Ld, kW	0	3944	1617	3944	1213	3944	809	3944	404	
		3944	1617	3944	1213	3944	809	3944	404	
COOLING, LOW										
fY heat,	nd	0.083	293	85	571	125	849	123	1127	82
CgB Ht Ld, kBtuh	652	2197	639	2197	479	2197	319	2197	160	
RoB Ht Ld, kBtuh	1545	293	85	571	125	840	122	840	61	
RoB AC Elec Ld, kW	15	1376	400	2681	585	3944	574	3944	287	
		652	190	652	142	652	95	652	47	
COOLING, MED										
fY heat,	nd	0.083	310	90	588	128	866	126	1144	83
CgB Ht Ld, kBtuh	1292	2837	825	2837	619	2837	413	2837	206	
RoB Ht Ld, kBtuh	1545	310	90	588	128	840	122	840	61	
RoB AC Elec Ld, kW	32	1456	423	2761	602	3944	574	3944	287	
		1292	376	1292	282	1292	188	1292	94	
COOLING, HIGH										
fY heat,	nd	0.042	366	54	644	71	922	68	1200	44
CgB Ht Ld, kBtuh	1292	2837	418	2837	313	2837	209	2837	104	
RoB Ht Ld, kBtuh	1545	366	54	644	71	840	62	840	31	
RoB AC Elec Ld, kW	88	1719	253	3024	334	3944	290	3944	145	
		1292	190	1292	143	1292	95	1292	48	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	4937				Ebought MWh/yr	256			
Hdemand kBtuh	MBtu/yr	33538				Esold MWh/yr	646			
Ecogen kW	MWh/yr	5327				Hboilers MBtu/yr	18828			
Hcogen kBtuh	MBtu/yr	25015								
Hused kBtuh	MBtu/yr	14710								

Cogen Heat Cap., kBtuh 3944.325 NORTHDIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		278		556		834		1112	
SHOULDER									
fy heat,	nd	0.209	278	204	556	305	834	305	1112
CgB Ht Ld, kBtuh		224	1545	1131	1545	849	1545	566	1545
RoB Ht Ld, kBtuh		1321	278	204	556	305	834	305	840
RoB AC Elec Ld, kW	0		1305	956	2611	1434	3916	1434	3944
			224	164	224	123	224	82	224
HEATING, LOW									
fy heat,	nd	0.233	278	227	556	340	834	340	1112
CgB Ht Ld, kBtuh		1658	3514	2869	3514	2152	3514	1434	3514
RoB Ht Ld, kBtuh		1856	353	288	556	340	834	340	840
RoB AC Elec Ld, kW	0		1658	1354	2611	1599	3916	1599	3944
			1658	1354	1658	1015	1658	677	1658
HEATING, MED									
fy heat,	nd	0.233	278	227	556	340	834	340	1112
CgB Ht Ld, kBtuh		3091	5484	4477	5484	3358	5484	2239	5484
RoB Ht Ld, kBtuh		2393	658	537	658	403	834	340	840
RoB AC Elec Ld, kW	0		3091	2524	3091	1893	3916	1599	3944
			3091	2524	3091	1893	3091	1262	3091
HEATING, HIGH									
fy heat,	nd	0.117	278	114	556	171	834	171	1112
CgB Ht Ld, kBtuh		4525	7454	3056	7454	2292	7454	1528	7454
RoB Ht Ld, kBtuh		2929	840	344	840	258	840	172	840
RoB AC Elec Ld, kW	0		3944	1617	3944	1213	3944	809	3944
			3944	1617	3944	1213	3944	809	3944
COOLING, LOW									
fy heat,	nd	0.083	334	97	612	133	890	129	1168
CgB Ht Ld, kBtuh		224	1545	449	1545	337	1545	225	1545
RoB Ht Ld, kBtuh		1321	334	97	612	133	840	122	840
RoB AC Elec Ld, kW	56		1568	456	2874	627	3944	574	3944
			224	65	224	49	224	33	224
COOLING, MED									
fy heat,	nd	0.083	391	114	669	146	947	138	1225
CgB Ht Ld, kBtuh		224	1545	449	1545	337	1545	225	1545
RoB Ht Ld, kBtuh		1321	391	114	669	146	840	122	840
RoB AC Elec Ld, kW	113		1836	534	3141	685	3944	574	3944
			224	65	224	49	224	33	224
COOLING, HIGH									
fy heat,	nd	0.042	447	66	725	80	1003	74	1281
CgB Ht Ld, kBtuh		224	1545	227	1545	171	1545	114	1545
RoB Ht Ld, kBtuh		1321	447	66	725	80	840	62	840
RoB AC Elec Ld, kW	169		2099	309	3404	376	3944	290	3944
			224	33	224	25	224	16	224
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr			5056		Ebought	MWh/yr	292	
Hdemand kBtuh	MBtu/yr			31649		Esold	MWh/yr	753	
Ecogen kW	MWh/yr			5517		Hboilers	MBtu/yr	17095	
Hcogen kBtuh	MBtu/yr			25907					
Hused kBtuh	MBtu/yr			14554					

Cogen Heat Cap., kBtuh 3944.325 NORTHDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		278	556			834		1112		
SHOULDER										
fY heat,	nd	0.209	278	204	556	305	834	305	1112	204
CgB Ht Ld, kBtuh	224	1545	1131	1545	849	1545	566	1545	283	
RoB Ht Ld, kBtuh	1321	278	204	556	305	834	305	840	154	
RoB AC Elec Ld, kW	0	1305	956	2611	1434	3916	1434	3944	722	
		224	164	224	123	224	82	224	41	
HEATING, LOW										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	1658	3514	2869	3514	2152	3514	1434	3514	717	
RoB Ht Ld, kBtuh	1856	353	288	556	340	834	340	840	171	
RoB AC Elec Ld, kW	0	1658	1354	2611	1599	3916	1599	3944	805	
		1658	1354	1658	1015	1658	677	1658	338	
HEATING, MED										
fY heat,	nd	0.233	278	227	556	340	834	340	1112	227
CgB Ht Ld, kBtuh	3091	5484	4477	5484	3358	5484	2239	5484	1119	
RoB Ht Ld, kBtuh	2393	658	537	658	403	834	340	840	171	
RoB AC Elec Ld, kW	0	3091	2524	3091	1893	3916	1599	3944	805	
		3091	2524	3091	1893	3091	1262	3091	631	
HEATING, HIGH										
fY heat,	nd	0.117	278	114	556	171	834	171	1112	114
CgB Ht Ld, kBtuh	4525	7454	3056	7454	2292	7454	1528	7454	764	
RoB Ht Ld, kBtuh	2929	840	344	840	258	840	172	840	86	
RoB AC Elec Ld, kW	0	3944	1617	3944	1213	3944	809	3944	404	
		3944	1617	3944	1213	3944	809	3944	404	
COOLING, LOW										
fY heat,	nd	0.083	293	85	571	125	849	123	1127	82
CgB Ht Ld, kBtuh	876	2197	639	2197	479	2197	319	2197	160	
RoB Ht Ld, kBtuh	1321	293	85	571	125	840	122	840	61	
RoB AC Elec Ld, kW	15	1376	400	2681	585	3944	574	3944	287	
		876	255	876	191	876	127	876	64	
COOLING, MED										
fY heat,	nd	0.083	310	90	588	128	866	126	1144	83
CgB Ht Ld, kBtuh	1516	2837	825	2837	619	2837	413	2837	206	
RoB Ht Ld, kBtuh	1321	323	94	588	128	840	122	840	61	
RoB AC Elec Ld, kW	32	1516	441	2761	602	3944	574	3944	287	
		1516	441	1516	331	1516	220	1516	110	
COOLING, HIGH										
fY heat,	nd	0.042	366	54	644	71	922	68	1200	44
CgB Ht Ld, kBtuh	1516	2837	418	2837	313	2837	209	2837	104	
RoB Ht Ld, kBtuh	1321	366	54	644	71	840	62	840	31	
RoB AC Elec Ld, kW	88	1719	253	3024	334	3944	290	3944	145	
		1516	223	1516	167	1516	112	1516	56	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	4937			Ebought	MWh/yr	256			
Hdemand kBtuh	MBtu/yr	33538			Esold	MWh/yr	757			
Ecogen kW	MWh/yr	5438			Hboilers	MBtu/yr	17095			
Hcogen kBtuh	MBtu/yr	25536								
Hused kBtuh	MBtu/yr	16443								

Cogen Heat Cap., kBtuh 3944.325 NORTHDIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

	Large Building 7	Small Building 9	Total for Site (1)	Units	Number of 10 ton Absorption Chillers per cogen unit
# of Buildings:					
Heating Demand:	Diversity	Factor =	50%		
7 Month Season					
Annual Energy:	1885	548	18126	MBtu	
Annual Peak:	820	238	7000	kBtuh	
Cooling Demand:	Diversity	Factor =	50%		
2.5 Month Season					
Annual Energy:	199	58	1916	MBtu	
Annual Peak:	242	71	2072	kBtuh	
Capacity	20.2	5.9	173	tons with	0
Requirement	10.2	5.9	na	tons	1
	0.2	5.9	na	tons	2
	0.0	5.9	na	tons	3
Electric Demand with EER 10.36 Btu/Wh, DF= 50%					
There are	1.0	1.0	1.0	0.5	months
when P(AC)=	31.1	87.4	143.7	200.0	0
(in kW)	31.1	31.1	65.9	122.2	1
	31.1	31.1	31.1	44.4	2
	31.1	31.1	31.1	31.1	3
Non-AC Electric:	Large	Small	Total	DF= 50%	
Annual Energy	507	147	4871	MWh	
Peak Demand:	145	42	1266	kW for	8.5 months
Total Electric Demand DF= 0%					
There are	1	1	1	0.5	months
when P(tot)=	1266	1322	1378	1434	0
(in kW)	1266	1266	1300	1357	1
	1266	1266	1266	1279	2
	1266	1266	1266	1266	3
Utility Demand with 9 120 kW cogenerators:					
There are	1	1	1	0.5	months
when P(tot)=	186	242	298	354	0 and
(in kW)	186	186	220	277	1 5
	186	186	186	199	2 with
	186	186	186	186	3 186
1 See discussion of diversity in text.					

Demand Table - NORTHDIV

SOUTHDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 684 kW

Low step = 0.5 X above = 342 kW

2nd step = 1.0 X above = 684 kW

3rd step = 1.5 X above = 1026 kW

4th step = 2.0 X above = 1368 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

1372 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 999 kBtuh = 200 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 2.5

HEATING SEASON: Months in season = 3.5

Low step multiplier = 6.667/months in season = 1.905

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.208	0	0	0
Low	0.117	739	276	0
Medium	0.117	1478	552	0
High	0.058	2217	829	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

SOUTHDIV SPREADSHEET INPUTS

COOLING: Months in season = 6.0

Low step multiplier = 6.667/months in season = 1.111

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.200	953	X 1.111	X 1/10.36	= 102
Med	0.200	953	X 1.111	X 2/10.36	= 204
High	0.100	953	X 1.111	X 3/10.36	= 307

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	770	289	770	1185	289	28
Med	1540	578	840	1292	1278	123
High	2310	867	840	1292	2337	226

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

If two chillers per cogenerator, the chillers again meet as much of the cooling load as they can, but now the limit is $2 \times 840 = 1680$ KBtuh of cooling load.

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	770	289	770	1185	289	28
Med	1540	578	1540	2369	578	56
High	2310	867	1680	2585	1497	144

COGEN ELEC. CAP., kW			HEAT/ELEC. RATIO, nd			1.375			
frac. of Year Elec.	nd		0.4		0.3		0.2		0.1
All Base nonAC Elec Ld, kW			342		684		1026		1368
SHOULDER									
fY heat, nd	0.208		342	249	684	374	1026	374	1368
CgB Ht Ld, kBtuh	0		1372	1000	1372	750	1372	500	1372
RoB Ht Ld, kBtuh	1372		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
HEATING, LOW									
fY heat, nd	0.117		342	140	684	210	1026	210	1368
CgB Ht Ld, kBtuh	739		2387	979	2387	734	2387	489	2387
RoB Ht Ld, kBtuh	1648		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
HEATING, MED									
fY heat, nd	0.117		342	140	684	210	1026	210	1368
CgB Ht Ld, kBtuh	1478		3402	1395	3402	1046	3402	697	3402
RoB Ht Ld, kBtuh	1924		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
HEATING, HIGH									
fY heat, nd	0.058		342	70	684	104	1026	104	1368
CgB Ht Ld, kBtuh	2217		4418	898	4418	673	4418	449	4418
RoB Ht Ld, kBtuh	2201		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
COOLING, LOW									
fY heat, nd	0.2		444	311	786	413	1128	395	1470
CgB Ht Ld, kBtuh	0		1372	961	1372	721	1372	481	1372
RoB Ht Ld, kBtuh	1372		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	102		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
COOLING, MED									
fY heat, nd	0.2		546	383	888	467	1230	431	1572
CgB Ht Ld, kBtuh	0		1372	961	1372	721	1372	481	1372
RoB Ht Ld, kBtuh	1372		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	204		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
COOLING, HIGH									
fY heat, nd	0.1		649	227	991	260	1333	234	1675
CgB Ht Ld, kBtuh	0		1372	481	1372	361	1372	240	1372
RoB Ht Ld, kBtuh	1372		0	0	0	0	0	0	0
RoB AC Elec Ld, kW	307		0	0	0	0	0	0	0
			0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		6797			Ebought	MWh/yr	6797	
Hdemand kBtuh	MBtu/yr		16687			Esold	MWh/yr	0	
Ecogen kW	MWh/yr		0			Hboilers	MBtu/yr	16687	
Hcogen kBtuh	MBtu/yr		0						
Hused kBtuh	MBtu/yr		0						

Cogen Heat Cap., kBtuh 0 SOUTHDIV, NO COGEN

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		342		684		1026		1368	
SHOULDER									
fY heat,	nd	0.208	342	249	684	374	1026	374	1368
CgB Ht Ld,	kBtuh	0	1372	1000	1372	750	1372	500	1372
RoB Ht Ld,	kBtuh	1372	342	249	684	374	840	306	840
RoB AC Elec Ld,	kW	0	1606	1170	3212	1756	3944	1437	3944
			0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld,	kBtuh	739	2387	979	2387	734	2387	489	2387
RoB Ht Ld,	kBtuh	1648	342	140	684	210	840	172	840
RoB AC Elec Ld,	kW	0	1606	658	3212	988	3944	809	3944
			739	303	739	227	739	151	739
HEATING, MED									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld,	kBtuh	1478	3402	1395	3402	1046	3402	697	3402
RoB Ht Ld,	kBtuh	1924	342	140	684	210	840	172	840
RoB AC Elec Ld,	kW	0	1606	658	3212	988	3944	809	3944
			1478	606	1478	454	1478	303	1478
HEATING, HIGH									
fY heat,	nd	0.058	342	70	684	104	1026	104	1368
CgB Ht Ld,	kBtuh	2217	4418	898	4418	673	4418	449	4418
RoB Ht Ld,	kBtuh	2201	472	96	684	104	840	85	840
RoB AC Elec Ld,	kW	0	2217	451	3212	490	3944	401	3944
			2217	451	2217	338	2217	225	2217
COOLING, LOW									
fY heat,	nd	0.2	444	311	786	413	1128	395	1470
CgB Ht Ld,	kBtuh	0	1372	961	1372	721	1372	481	1372
RoB Ht Ld,	kBtuh	1372	444	311	786	413	840	294	840
RoB AC Elec Ld,	kW	102	2085	1461	3691	1940	3944	1382	3944
			0	0	0	0	0	0	0
COOLING, MED									
fY heat,	nd	0.2	546	383	888	467	1230	431	1572
CgB Ht Ld,	kBtuh	0	1372	961	1372	721	1372	481	1372
RoB Ht Ld,	kBtuh	1372	546	383	840	442	840	294	840
RoB AC Elec Ld,	kW	204	2564	1797	3944	2073	3944	1382	3944
			0	0	0	0	0	0	0
COOLING, HIGH									
fY heat,	nd	0.1	649	227	991	260	1333	234	1675
CgB Ht Ld,	kBtuh	0	1372	481	1372	361	1372	240	1372
RoB Ht Ld,	kBtuh	1372	649	227	840	221	840	147	840
RoB AC Elec Ld,	kW	307	3047	1068	3944	1037	3944	691	3944
			0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr			6797		Ebought MWh/yr	1095		
Hdemand kBtuh	MBtu/yr			16687		Esold MWh/yr	26		
Ecogen kW	MWh/yr			5729		Hboilers MBtu/yr	13289		
Hcogen kBtuh	MBtu/yr			26899					
Hused kBtuh	MBtu/yr			3399					

Cogen Heat Cap., kBtuh 3944.325 SOUTH DIV, NO CHILLERS, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		342		684		1026		1368	
SHOULDER									
fY heat,	nd	0.208	342	249	684	374	1026	374	1368
CgB Ht Ld, kBtuh	0	1372	1000	1372	750	1372	500	1372	250
RoB Ht Ld, kBtuh	1372	342	249	684	374	840	306	840	153
RoB AC Elec Ld, kW	0	1606	1170	3212	1756	3944	1437	3944	719
		0	0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld, kBtuh	739	2387	979	2387	734	2387	489	2387	245
RoB Ht Ld, kBtuh	1648	342	140	684	210	840	172	840	86
RoB AC Elec Ld, kW	0	1606	658	3212	988	3944	809	3944	404
		739	303	739	227	739	151	739	76
HEATING, MED									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld, kBtuh	1478	3402	1395	3402	1046	3402	697	3402	349
RoB Ht Ld, kBtuh	1924	342	140	684	210	840	172	840	86
RoB AC Elec Ld, kW	0	1606	658	3212	988	3944	809	3944	404
		1478	606	1478	454	1478	303	1478	151
HEATING, HIGH									
fY heat,	nd	0.058	342	70	684	104	1026	104	1368
CgB Ht Ld, kBtuh	2217	4418	898	4418	673	4418	449	4418	224
RoB Ht Ld, kBtuh	2201	472	96	684	104	840	85	840	43
RoB AC Elec Ld, kW	0	2217	451	3212	490	3944	401	3944	200
		2217	451	2217	338	2217	225	2217	113
COOLING, LOW									
fY heat,	nd	0.2	370	259	712	374	1054	369	1396
CgB Ht Ld, kBtuh	1185	2557	1792	2557	1344	2557	896	2557	448
RoB Ht Ld, kBtuh	1372	370	259	712	374	840	294	840	147
RoB AC Elec Ld, kW	28	1737	1218	3343	1757	3944	1382	3944	691
		1185	830	1185	623	1185	415	1185	208
COOLING, MED									
fY heat,	nd	0.2	465	326	807	424	1149	403	1491
CgB Ht Ld, kBtuh	1292	2664	1867	2664	1400	2664	933	2664	467
RoB Ht Ld, kBtuh	1372	465	326	807	424	840	294	840	147
RoB AC Elec Ld, kW	123	2183	1530	3789	1992	3944	1382	3944	691
		1292	905	1292	679	1292	453	1292	226
COOLING, HIGH									
fY heat,	nd	0.1	568	199	910	239	1252	219	1594
CgB Ht Ld, kBtuh	1292	2664	933	2664	700	2664	467	2664	233
RoB Ht Ld, kBtuh	1372	568	199	840	221	840	147	840	74
RoB AC Elec Ld, kW	226	2667	935	3944	1037	3944	691	3944	346
		1292	453	1292	340	1292	226	1292	113
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		6454		Ebought	MWh/yr	946		
Hdemand kBtuh	MBtu/yr		22159		Esold	MWh/yr	26		
Ecogen kW	MWh/yr		5535		Hboilers	MBtu/yr	13289		
Hcogen kBtuh	MBtu/yr		25992						
Hused kBtuh	MBtu/yr		8870						

Cogen Heat Cap., kBtuh 3944.325 SOUTH DIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		342		684		1026		1368	
SHOULDER									
fY heat,	nd	0.208	342	249	684	374	1026	374	1368
CgB Ht Ld,	kBtuh	0	1372	1000	1372	750	1372	500	1372
RoB Ht Ld,	kBtuh	1372	342	249	684	374	840	306	840
RoB AC Elec Ld,	kW	0	1606	1170	3212	1756	3944	1437	3944
			0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld,	kBtuh	739	2387	979	2387	734	2387	489	2387
RoB Ht Ld,	kBtuh	1648	342	140	684	210	840	172	840
RoB AC Elec Ld,	kW	0	1606	658	3212	988	3944	809	3944
			739	303	739	227	739	151	739
HEATING, MED									
fY heat,	nd	0.117	342	140	684	210	1026	210	1368
CgB Ht Ld,	kBtuh	1478	3402	1395	3402	1046	3402	697	3402
RoB Ht Ld,	kBtuh	1924	342	140	684	210	840	172	840
RoB AC Elec Ld,	kW	0	1606	658	3212	988	3944	809	3944
			1478	606	1478	454	1478	303	1478
HEATING, HIGH									
fY heat,	nd	0.058	342	70	684	104	1026	104	1368
CgB Ht Ld,	kBtuh	2217	4418	898	4418	673	4418	449	4418
RoB Ht Ld,	kBtuh	2201	472	96	684	104	840	85	840
RoB AC Elec Ld,	kW	0	2217	451	3212	490	3944	401	3944
			2217	451	2217	338	2217	225	2217
COOLING, LOW									
fY heat,	nd	0.2	370	259	712	374	1054	369	1396
CgB Ht Ld,	kBtuh	1185	2557	1792	2557	1344	2557	896	2557
RoB Ht Ld,	kBtuh	1372	370	259	712	374	840	294	840
RoB AC Elec Ld,	kW	28	1737	1218	3343	1757	3944	1382	3944
			1185	830	1185	623	1185	415	1185
COOLING, MED									
fY heat,	nd	0.2	398	279	740	389	1082	379	1424
CgB Ht Ld,	kBtuh	2369	3741	2622	3741	1966	3741	1311	3741
RoB Ht Ld,	kBtuh	1372	505	354	740	389	840	294	840
RoB AC Elec Ld,	kW	56	2369	1660	3475	1826	3944	1382	3944
			2369	1660	2369	1245	2369	830	2369
COOLING, HIGH									
fY heat,	nd	0.1	486	170	828	218	1170	205	1512
CgB Ht Ld,	kBtuh	2585	3957	1387	3957	1040	3957	693	3957
RoB Ht Ld,	kBtuh	1372	551	193	828	218	840	147	840
RoB AC Elec Ld,	kW	144	2585	906	3888	1022	3944	691	3944
			2585	906	2585	679	2585	453	2585
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr			6265		Ebought MWh/yr	870		
Hdemand kBtuh	MBtu/yr			25178		Esold MWh/yr	124		
Ecogen kW	MWh/yr			5518		Hboilers MBtu/yr	13289		
Hcogen kBtuh	MBtu/yr			25913					
Hused kBtuh	MBtu/yr			11890					

Cogen Heat Cap., kBtuh 3944.325 SOUTH DIV, 2 CHILLERS/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2			0.1		
All Base nonAC Elec Ld, kW		342	684		1026			1368		
SHOULDER										
fY heat,	nd	0.208	342	249	684	374	1026	374	1368	249
CgB Ht Ld, kBtuh	200	1372	1000	1372	750	1372	500	1372	250	
RoB Ht Ld, kBtuh	1172	342	249	684	374	840	306	840	153	
RoB AC Elec Ld, kW	0	1606	1170	3212	1756	3944	1437	3944	719	
		200	146	200	109	200	73	200	36	
HEATING, LOW										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	939	2387	979	2387	734	2387	489	2387	245	
RoB Ht Ld, kBtuh	1448	342	140	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1606	658	3212	988	3944	809	3944	404	
		939	385	939	289	939	192	939	96	
HEATING, MED										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	1678	3402	1395	3402	1046	3402	697	3402	349	
RoB Ht Ld, kBtuh	1724	357	147	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1678	688	3212	988	3944	809	3944	404	
		1678	688	1678	516	1678	344	1678	172	
HEATING, HIGH										
fY heat,	nd	0.058	342	70	684	104	1026	104	1368	70
CgB Ht Ld, kBtuh	2417	4418	898	4418	673	4418	449	4418	224	
RoB Ht Ld, kBtuh	2001	515	105	684	104	840	85	840	43	
RoB AC Elec Ld, kW	0	2417	491	3212	490	3944	401	3944	200	
		2417	491	2417	368	2417	246	2417	123	
COOLING, LOW										
fY heat,	nd	0.2	444	311	786	413	1128	395	1470	258
CgB Ht Ld, kBtuh	200	1372	961	1372	721	1372	481	1372	240	
RoB Ht Ld, kBtuh	1172	444	311	786	413	840	294	840	147	
RoB AC Elec Ld, kW	102	2085	1461	3691	1940	3944	1382	3944	691	
		200	140	200	105	200	70	200	35	
COOLING, MED										
fY heat,	nd	0.2	546	383	888	467	1230	431	1572	275
CgB Ht Ld, kBtuh	200	1372	961	1372	721	1372	481	1372	240	
RoB Ht Ld, kBtuh	1172	546	383	840	442	840	294	840	147	
RoB AC Elec Ld, kW	204	2564	1797	3944	2073	3944	1382	3944	691	
		200	140	200	105	200	70	200	35	
COOLING, HIGH										
fY heat,	nd	0.1	649	227	991	260	1333	234	1675	147
CgB Ht Ld, kBtuh	200	1372	481	1372	361	1372	240	1372	120	
RoB Ht Ld, kBtuh	1172	649	227	840	221	840	147	840	74	
RoB AC Elec Ld, kW	307	3047	1068	3944	1037	3944	691	3944	346	
		200	70	200	53	200	35	200	18	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	6797			Ebought	MWh/yr	1095			
Hdemand kBtuh	MBtu/yr	16687			Esold	MWh/yr	41			
Ecogen kW	MWh/yr	5743			Hboilers	MBtu/yr	11537			
Hcogen kBtuh	MBtu/yr	26969								
Hused kBtuh	MBtu/yr	5151								

Cogen Heat Cap., kBtuh 3944.325 SOUTHDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2			0.1		
All Base nonAC Elec Ld, kW		342	684		1026			1368		
SHOULDER										
fY heat,	nd	0.208	342	249	684	374	1026	374	1368	249
CgB Ht Ld, kBtuh	200	1372	1000	1372	750	1372	500	1372	250	
RoB Ht Ld, kBtuh	1172	342	249	684	374	840	306	840	153	
RoB AC Elec Ld, kW	0	1606	1170	3212	1756	3944	1437	3944	719	
		200	146	200	109	200	73	200	36	
HEATING, LOW										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	939	2387	979	2387	734	2387	489	2387	245	
RoB Ht Ld, kBtuh	1448	342	140	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1606	658	3212	988	3944	809	3944	404	
		939	385	939	289	939	192	939	96	
HEATING, MED										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	1678	3402	1395	3402	1046	3402	697	3402	349	
RoB Ht Ld, kBtuh	1724	357	147	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1678	688	3212	988	3944	809	3944	404	
		1678	688	1678	516	1678	344	1678	172	
HEATING, HIGH										
fY heat,	nd	0.058	342	70	684	104	1026	104	1368	70
CgB Ht Ld, kBtuh	2417	4418	898	4418	673	4418	449	4418	224	
RoB Ht Ld, kBtuh	2001	515	105	684	104	840	85	840	43	
RoB AC Elec Ld, kW	0	2417	491	3212	490	3944	401	3944	200	
		2417	491	2417	368	2417	246	2417	123	
COOLING, LOW										
fY heat,	nd	0.2	370	259	712	374	1054	369	1396	245
CgB Ht Ld, kBtuh	1385	2557	1792	2557	1344	2557	896	2557	448	
RoB Ht Ld, kBtuh	1172	370	259	712	374	840	294	840	147	
RoB AC Elec Ld, kW	28	1737	1218	3343	1757	3944	1382	3944	691	
		1385	971	1385	728	1385	485	1385	243	
COOLING, MED										
fY heat,	nd	0.2	465	326	807	424	1149	403	1491	261
CgB Ht Ld, kBtuh	1492	2664	1867	2664	1400	2664	933	2664	467	
RoB Ht Ld, kBtuh	1172	465	326	807	424	840	294	840	147	
RoB AC Elec Ld, kW	123	2183	1530	3789	1992	3944	1382	3944	691	
		1492	1046	1492	784	1492	523	1492	261	
COOLING, HIGH										
fY heat,	nd	0.1	568	199	910	239	1252	219	1594	140
CgB Ht Ld, kBtuh	1492	2664	933	2664	700	2664	467	2664	233	
RoB Ht Ld, kBtuh	1172	568	199	840	221	840	147	840	74	
RoB AC Elec Ld, kW	226	2667	935	3944	1037	3944	691	3944	346	
		1492	523	1492	392	1492	261	1492	131	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	6454			Ebought MWh/yr	946				
Hdemand kBtuh	MBtu/yr	22159			Esold MWh/yr	41				
Ecogen kW	MWh/yr	5550			Hboilers MBtu/yr	11537				
Hcogen kBtuh	MBtu/yr	26062								
Hused kBtuh	MBtu/yr	10622								

Cogen Heat Cap., kBtuh 3944.325 SOUTH DIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		342	684			1026		1368		
SHOULDER										
fY heat,	nd	0.208	342	249	684	374	1026	374	1368	249
CgB Ht Ld, kBtuh	200	1372	1000	1372	750	1372	500	1372	250	
RoB Ht Ld, kBtuh	1172	342	249	684	374	840	306	840	153	
RoB AC Elec Ld, kW	0	1606	1170	3212	1756	3944	1437	3944	719	
		200	146	200	109	200	73	200	36	
HEATING, LOW										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	939	2387	979	2387	734	2387	489	2387	245	
RoB Ht Ld, kBtuh	1448	342	140	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1606	658	3212	988	3944	809	3944	404	
		939	385	939	289	939	192	939	96	
HEATING, MED										
fY heat,	nd	0.117	342	140	684	210	1026	210	1368	140
CgB Ht Ld, kBtuh	1678	3402	1395	3402	1046	3402	697	3402	349	
RoB Ht Ld, kBtuh	1724	357	147	684	210	840	172	840	86	
RoB AC Elec Ld, kW	0	1678	688	3212	988	3944	809	3944	404	
		1678	688	1678	516	1678	344	1678	172	
HEATING, HIGH										
fY heat,	nd	0.058	342	70	684	104	1026	104	1368	70
CgB Ht Ld, kBtuh	2417	4418	898	4418	673	4418	449	4418	224	
RoB Ht Ld, kBtuh	2001	515	105	684	104	840	85	840	43	
RoB AC Elec Ld, kW	0	2417	491	3212	490	3944	401	3944	200	
		2417	491	2417	368	2417	246	2417	123	
COOLING, LOW										
fY heat,	nd	0.2	370	259	712	374	1054	369	1396	245
CgB Ht Ld, kBtuh	1385	2557	1792	2557	1344	2557	896	2557	448	
RoB Ht Ld, kBtuh	1172	370	259	712	374	840	294	840	147	
RoB AC Elec Ld, kW	28	1737	1218	3343	1757	3944	1382	3944	691	
		1385	971	1385	728	1385	485	1385	243	
COOLING, MED										
fY heat,	nd	0.2	398	279	740	389	1082	379	1424	249
CgB Ht Ld, kBtuh	2569	3741	2622	3741	1966	3741	1311	3741	655	
RoB Ht Ld, kBtuh	1172	547	383	740	389	840	294	840	147	
RoB AC Elec Ld, kW	56	2569	1800	3475	1826	3944	1382	3944	691	
		2569	1800	2569	1350	2569	900	2569	450	
COOLING, HIGH										
fY heat,	nd	0.1	486	170	828	218	1170	205	1512	132
CgB Ht Ld, kBtuh	2785	3957	1387	3957	1040	3957	693	3957	347	
RoB Ht Ld, kBtuh	1172	593	208	828	218	840	147	840	74	
RoB AC Elec Ld, kW	144	2785	976	3888	1022	3944	691	3944	346	
		2785	976	2785	732	2785	488	2785	244	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	6265			Ebought	MWh/yr	870		
Hdemand	kBtuh	MBtu/yr	25178			Esold	MWh/yr	183		
Ecogen	kW	MWh/yr	5578			Hboilers	MBtu/yr	11537		
Hcogen	kBtuh	MBtu/yr	26193							
Hused	kBtuh	MBtu/yr	13642							

Cogen Heat Cap., kBtuh 3944.325 SOUTH DIV, 2 CHILLERS/COGEN, 20% PROC. HEAT IN CgB

# of Buildings:	Large Building 7	Small Building 9	Total for Site (1)	Units	Number of 10 ton Absorption Chillers per cogen unit	
Heating Demand:	Diversity	Factor =	50%			
3.5 Month Season						
Annual Energy:	486	141	4671	MBtu		
Annual Peak:	423	123	3608	kBtuh		
Cooling Demand:	Diversity	Factor =	50%			
6 Month Season						
Annual Energy:	868	252	8344	MBtu		
Annual Peak:	440	128	3759	kBtuh		
Capacity	36.7	10.7	313	tons with	0	
Requirement	26.7	10.7	na	tons	1	
	16.7	10.7	na	tons	2	
	6.7	10.7	na	tons	3	
Electric Demand with EER			10.36 Btu/Wh,	DF= 50%		
There are	2.4	2.4	2.4	1.2	months	
when P(AC)=	56.4	158.5	260.7	362.9	0	
(in kW)	56.4	80.8	182.9	285.1	1	
	56.4	56.4	105.2	207.3	2	
	56.4	56.4	56.4	129.5	3	
Non-AC Electric:	Large	Small	Total	DF= 50%		
Annual Energy	623	181	5989	MWh		
Peak Demand:	178	52	1556	kW for	3.6 months	
Total Electric Demand			DF= 0%			
There are	2.4	2.4	2.4	1.2	months	
when P(tot)=	1556	1658	1760	1863	0	
(in kW)	1556	1580	1683	1785	1	
	1556	1556	1605	1707	2	
	1556	1556	1556	1629	3	
Utility Demand with		9	120 kW cogenerators:			
There are	2.4	2.4	2.4	1.2	months	
when P(tot)=	476	578	680	783	0	and
(in kW)	476	500	603	705	1	5
	476	476	525	627	2	with
	476	476	476	549	3	476
1 See discussion of diversity in text.						

Demand Table - SOUTH DIV

WESTDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 538 kW

Low step = 0.5 X above = 269 kW

2nd step = 1.0 X above = 538 kW

3rd step = 1.5 X above = 807 kW

4th step = 2.0 X above = 1076 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

1600 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 1164 kBtuh = 116 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 4.0

HEATING SEASON: Months in season = 6.0

Low step multiplier = 6.667/months in season = 1.111

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.333	0	0	0
Low	0.200	538	201	0
Medium	0.200	1075	402	0
High	0.100	1613	603	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

WESTDIV SPREADSHEET INPUTS

COOLING: Months in season = 2.0

Low step multiplier = 6.667/months in season = 3.333

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.067	91	X 3.333	X 1/10.36	= 29
Med	0.067	91	X 3.333	X 2/10.36	= 59
High	0.033	91	X 3.333	X 3/10.36	= 88

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	220	83	220	338	83	8
Med	440	167	440	677	167	16
High	660	250	660	1014	250	24

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

COGEN ELEC. CAP., kW		0	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		269		538		807		1076	
SHOULDER									
fY heat,	nd	0.333	269	314	538	471	807	471	1076
CgB Ht Ld, kBtuh	0	1600	1867	1600	1400	1600	933	1600	467
RoB Ht Ld, kBtuh	1600	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.2	269	189	538	283	807	283	1076
CgB Ht Ld, kBtuh	538	2339	1639	2339	1229	2339	820	2339	410
RoB Ht Ld, kBtuh	1801	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, MED									
fY heat,	nd	0.2	269	189	538	283	807	283	1076
CgB Ht Ld, kBtuh	1075	3077	2156	3077	1617	3077	1078	3077	539
RoB Ht Ld, kBtuh	2002	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, HIGH									
fY heat,	nd	0.1	269	94	538	141	807	141	1076
CgB Ht Ld, kBtuh	1613	3816	1337	3816	1003	3816	669	3816	334
RoB Ht Ld, kBtuh	2203	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, LOW									
fY heat,	nd	0.067	298	70	567	100	836	98	1105
CgB Ht Ld, kBtuh	0	1600	376	1600	282	1600	188	1600	94
RoB Ht Ld, kBtuh	1600	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	29	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, MED									
fY heat,	nd	0.067	328	77	597	105	866	102	1135
CgB Ht Ld, kBtuh	0	1600	376	1600	282	1600	188	1600	94
RoB Ht Ld, kBtuh	1600	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	59	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, HIGH									
fY heat,	nd	0.033	357	41	626	54	895	52	1164
CgB Ht Ld, kBtuh	0	1600	185	1600	139	1600	93	1600	46
RoB Ht Ld, kBtuh	1600	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	88	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		4790		Ebought	MWh/yr	4790		
Hdemand kBtuh	MBtu/yr		19840		Esold	MWh/yr	0		
Ecogen kW	MWh/yr		0		Hboilers	MBtu/yr	19840		
Hcogen kBtuh	MBtu/yr		0						
Hused kBtuh	MBtu/yr		0						

Cogen Heat Cap., kBtuh

0 WESTDIV, NO COGEN

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		269	538			807		1076		
SHOULDER										
fY heat,	nd	0.333	269	314	538	471	807	471	1076	314
CgB Ht Ld, kBtuh	0	1600	1867	1600	1400	1600	933	1600	467	
RoB Ht Ld, kBtuh	1600	269	314	538	471	807	471	840	245	
RoB AC Elec Ld, kW	0	1263	1474	2526	2211	3789	2211	3944	1151	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	538	2339	1639	2339	1229	2339	820	2339	410	
RoB Ht Ld, kBtuh	1801	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		538	377	538	283	538	189	538	94	
HEATING, MED										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	1075	3077	2156	3077	1617	3077	1078	3077	539	
RoB Ht Ld, kBtuh	2002	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		1075	753	1075	565	1075	377	1075	188	
HEATING, HIGH										
fY heat,	nd	0.1	269	94	538	141	807	141	1076	94
CgB Ht Ld, kBtuh	1613	3816	1337	3816	1003	3816	669	3816	334	
RoB Ht Ld, kBtuh	2203	344	120	538	141	807	141	840	74	
RoB AC Elec Ld, kW	0	1613	565	2526	664	3789	664	3944	346	
		1613	565	1613	424	1613	283	1613	141	
COOLING, LOW										
fY heat,	nd	0.067	298	70	567	100	836	98	1105	65
CgB Ht Ld, kBtuh	0	1600	376	1600	282	1600	188	1600	94	
RoB Ht Ld, kBtuh	1600	298	70	567	100	836	98	840	49	
RoB AC Elec Ld, kW	29	1399	329	2662	469	3926	461	3944	232	
		0	0	0	0	0	0	0	0	
COOLING, MED										
fY heat,	nd	0.067	328	77	597	105	866	102	1135	67
CgB Ht Ld, kBtuh	0	1600	376	1600	282	1600	188	1600	94	
RoB Ht Ld, kBtuh	1600	328	77	597	105	840	99	840	49	
RoB AC Elec Ld, kW	59	1540	362	2803	494	3944	463	3944	232	
		0	0	0	0	0	0	0	0	
COOLING, HIGH										
fY heat,	nd	0.033	357	41	626	54	895	52	1164	34
CgB Ht Ld, kBtuh	0	1600	185	1600	139	1600	93	1600	46	
RoB Ht Ld, kBtuh	1600	357	41	626	54	840	49	840	24	
RoB AC Elec Ld, kW	88	1676	194	2939	255	3944	228	3944	114	
		0	0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	4790			Ebought	MWh/yr	221			
Hdemand kBtuh	MBtu/yr	19840			Esold	MWh/yr	26			
Ecogen kW	MWh/yr	4595			Hboilers	MBtu/yr	15601			
Hcogen kBtuh	MBtu/yr	21578								
Hused kBtuh	MBtu/yr	4239								

Cogen Heat Cap., kBtuh 3944.325 WESTDIV, NO CHILLERS, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		269	538			807		1076		
SHOULDER										
fY heat,	nd	0.333	269	314	538	471	807	471	1076	314
CgB Ht Ld, kBtuh	0	1600	1867	1600	1400	1600	933	1600	467	
RoB Ht Ld, kBtuh	1600	269	314	538	471	807	471	840	245	
RoB AC Elec Ld, kW	0	1263	1474	2526	2211	3789	2211	3944	1151	
		0	0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	538	2339	1639	2339	1229	2339	820	2339	410	
RoB Ht Ld, kBtuh	1801	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		538	377	538	283	538	189	538	94	
HEATING, MED										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	1075	3077	2156	3077	1617	3077	1078	3077	539	
RoB Ht Ld, kBtuh	2002	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		1075	753	1075	565	1075	377	1075	188	
HEATING, HIGH										
fY heat,	nd	0.1	269	94	538	141	807	141	1076	94
CgB Ht Ld, kBtuh	1613	3816	1337	3816	1003	3816	669	3816	334	
RoB Ht Ld, kBtuh	2203	344	120	538	141	807	141	840	74	
RoB AC Elec Ld, kW	0	1613	565	2526	664	3789	664	3944	346	
		1613	565	1613	424	1613	283	1613	141	
COOLING, LOW										
fY heat,	nd	0.067	277	65	546	96	815	96	1084	64
CgB Ht Ld, kBtuh	338	1938	455	1938	341	1938	227	1938	114	
RoB Ht Ld, kBtuh	1600	277	65	546	96	815	96	840	49	
RoB AC Elec Ld, kW	8	1301	305	2564	451	3827	449	3944	232	
		338	79	338	60	338	40	338	20	
COOLING, MED										
fY heat,	nd	0.067	285	67	554	98	823	97	1092	64
CgB Ht Ld, kBtuh	677	2277	535	2277	401	2277	267	2277	134	
RoB Ht Ld, kBtuh	1600	285	67	554	98	823	97	840	49	
RoB AC Elec Ld, kW	16	1338	314	2601	458	3864	454	3944	232	
		677	159	677	119	677	79	677	40	
COOLING, HIGH										
fY heat,	nd	0.033	293	34	562	49	831	48	1100	32
CgB Ht Ld, kBtuh	1014	2614	302	2614	227	2614	151	2614	76	
RoB Ht Ld, kBtuh	1600	293	34	562	49	831	48	840	24	
RoB AC Elec Ld, kW	24	1376	159	2639	229	3902	226	3944	114	
		1014	117	1014	88	1014	59	1014	29	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	4734			Ebought	MWh/yr	209			
Hdemand kBtuh	MBtu/yr	20728			Esold	MWh/yr	26			
Ecogen kW	MWh/yr	4551			Hboilers	MBtu/yr	15601			
Hcogen kBtuh	MBtu/yr	21371								
Hused kBtuh	MBtu/yr	5128								

Cogen Heat Cap., kBtuh 3944.325 WESTDIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1		
All Base nonAC Elec Ld, kW		269		538		807		1076		
SHOULDER										
fY heat,	nd	0.333	269	314	538	471	807	471	1076	314
CgB Ht Ld, kBtuh	233	1600	1867	1600	1400	1600	933	1600	467	
RoB Ht Ld, kBtuh	1367	269	314	538	471	807	471	840	245	
RoB AC Elec Ld, kW	0	1263	1474	2526	2211	3789	2211	3944	1151	
		233	272	233	204	233	136	233	68	
HEATING, LOW										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	771	2339	1639	2339	1229	2339	820	2339	410	
RoB Ht Ld, kBtuh	1568	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		771	540	771	405	771	270	771	135	
HEATING, MED										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	1308	3077	2156	3077	1617	3077	1078	3077	539	
RoB Ht Ld, kBtuh	1769	279	195	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1308	917	2526	1328	3789	1328	3944	691	
		1308	917	1308	687	1308	458	1308	229	
HEATING, HIGH										
fY heat,	nd	0.1	269	94	538	141	807	141	1076	94
CgB Ht Ld, kBtuh	1846	3816	1337	3816	1003	3816	669	3816	334	
RoB Ht Ld, kBtuh	1970	393	138	538	141	807	141	840	74	
RoB AC Elec Ld, kW	0	1846	647	2526	664	3789	664	3944	346	
		1846	647	1846	485	1846	323	1846	162	
COOLING, LOW										
fY heat,	nd	0.067	298	70	567	100	836	98	1105	65
CgB Ht Ld, kBtuh	233	1600	376	1600	282	1600	188	1600	94	
RoB Ht Ld, kBtuh	1367	298	70	567	100	836	98	840	49	
RoB AC Elec Ld, kW	29	1399	329	2662	469	3926	461	3944	232	
		233	55	233	41	233	27	233	14	
COOLING, MED										
fY heat,	nd	0.067	328	77	597	105	866	102	1135	67
CgB Ht Ld, kBtuh	233	1600	376	1600	282	1600	188	1600	94	
RoB Ht Ld, kBtuh	1367	328	77	597	105	840	99	840	49	
RoB AC Elec Ld, kW	59	1540	362	2803	494	3944	463	3944	232	
		233	55	233	41	233	27	233	14	
COOLING, HIGH										
fY heat,	nd	0.033	357	41	626	54	895	52	1164	34
CgB Ht Ld, kBtuh	233	1600	185	1600	139	1600	93	1600	46	
RoB Ht Ld, kBtuh	1367	357	41	626	54	840	49	840	24	
RoB AC Elec Ld, kW	88	1676	194	2939	255	3944	228	3944	114	
		233	27	233	20	233	13	233	7	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	4790			Ebought	MWh/yr	221		
Hdemand	kBtuh	MBtu/yr	19840			Esold	MWh/yr	50		
Ecogen	kW	MWh/yr	4619			Hboilers	MBtu/yr	13560		
Hcogen	kBtuh	MBtu/yr	21691							
Hused	kBtuh	MBtu/yr	6280							

Cogen Heat Cap., kBtuh 3944.325 WESTDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2		0.1			
All Base nonAC Elec Ld, kW		269	538		807		1076			
SHOULDER										
fY heat,	nd	0.333	269	314	538	471	807	471	1076	314
CgB Ht Ld, kBtuh	233	1600	1867	1600	1400	1600	933	1600	467	
RoB Ht Ld, kBtuh	1367	269	314	538	471	807	471	840	245	
RoB AC Elec Ld, kW	0	1263	1474	2526	2211	3789	2211	3944	1151	
		233	272	233	204	233	136	233	68	
HEATING, LOW										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	771	2339	1639	2339	1229	2339	820	2339	410	
RoB Ht Ld, kBtuh	1568	269	189	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1263	885	2526	1328	3789	1328	3944	691	
		771	540	771	405	771	270	771	135	
HEATING, MED										
fY heat,	nd	0.2	269	189	538	283	807	283	1076	189
CgB Ht Ld, kBtuh	1308	3077	2156	3077	1617	3077	1078	3077	539	
RoB Ht Ld, kBtuh	1769	279	195	538	283	807	283	840	147	
RoB AC Elec Ld, kW	0	1308	917	2526	1328	3789	1328	3944	691	
		1308	917	1308	687	1308	458	1308	229	
HEATING, HIGH										
fY heat,	nd	0.1	269	94	538	141	807	141	1076	94
CgB Ht Ld, kBtuh	1846	3816	1337	3816	1003	3816	669	3816	334	
RoB Ht Ld, kBtuh	1970	393	138	538	141	807	141	840	74	
RoB AC Elec Ld, kW	0	1846	647	2526	664	3789	664	3944	346	
		1846	647	1846	485	1846	323	1846	162	
COOLING, LOW										
fY heat,	nd	0.067	277	65	546	96	815	96	1084	64
CgB Ht Ld, kBtuh	571	1938	455	1938	341	1938	227	1938	114	
RoB Ht Ld, kBtuh	1367	277	65	546	96	815	96	840	49	
RoB AC Elec Ld, kW	8	1301	305	2564	451	3827	449	3944	232	
		571	134	571	101	571	67	571	34	
COOLING, MED										
fY heat,	nd	0.067	285	67	554	98	823	97	1092	64
CgB Ht Ld, kBtuh	910	2277	535	2277	401	2277	267	2277	134	
RoB Ht Ld, kBtuh	1367	285	67	554	98	823	97	840	49	
RoB AC Elec Ld, kW	16	1338	314	2601	458	3864	454	3944	232	
		910	214	910	160	910	107	910	53	
COOLING, HIGH										
fY heat,	nd	0.033	293	34	562	49	831	48	1100	32
CgB Ht Ld, kBtuh	1247	2614	302	2614	227	2614	151	2614	76	
RoB Ht Ld, kBtuh	1367	293	34	562	49	831	48	840	24	
RoB AC Elec Ld, kW	24	1376	159	2639	229	3902	226	3944	114	
		1247	144	1247	108	1247	72	1247	36	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	4734			Ebought MWh/yr	209				
Hdemand kBtuh	MBtu/yr	20728			Esold MWh/yr	50				
Ecogen kW	MWh/yr	4575			Hboilers MBtu/yr	13560				
Hcogen kBtuh	MBtu/yr	21484								
Hused kBtuh	MBtu/yr	7169								

Cogen Heat Cap., kBtuh 3944.325 WESTDIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

	Large Building	Small Building	Total for Site (1)	Units	Number of 10 ton Absorption Chillers per cogen unit
# of Buildings:	7	9			
Heating Demand:	Diversity	Factor =	50%		
6 Month Season					
Annual Energy:	606	176	5829	MBtu	
Annual Peak:	307	89	2626	kBtuh	
Cooling Demand:	Diversity	Factor =	50%		
2 Month Season					
Annual Energy:	83	24	798	MBtu	
Annual Peak:	126	37	1079	kBtuh	
Capacity	10.5	3.1	90	tons with	0
Requirement	0.5	3.1	na	tons	1
	0.0	3.1	na	tons	2
	0.0	3.1	na	tons	3
Electric Demand with EER 10.36 Btu/Wh, DF= 50%					
There are	0.8	0.8	0.8	0.4	months
when P(AC)=	16.2	45.5	74.8	104.1	0
(in kW)	16.2	16.2	16.2	26.3	1
	16.2	16.2	16.2	16.2	2
	16.2	16.2	16.2	16.2	3
Non-AC Electric:	Large	Small	Total		DF= 50%
Annual Energy	490	142	4711	MWh	
Peak Demand:	140	41	1224	kW for	9.2 months
Total Electric Demand DF= 0%					
There are	0.8	0.8	0.8	0.4	months
when P(tot)=	1224	1253	1283	1312	0
(in kW)	1224	1224	1224	1234	1
	1224	1224	1224	1224	2
	1224	1224	1224	1224	3
Utility Demand with 9 120 kW cogenerators:					
There are	0.8	0.8	0.8	0.4	months
when P(tot)=	144	173	203	232	0 and
(in kW)	144	144	144	154	1 5
	144	144	144	144	2 with
	144	144	144	144	3 144
1 See discussion of diversity in text.					

Demand Table - WESTDIV

SWESTDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 428 kW

Low step = 0.5 X above = 214 kW

2nd step = 1.0 X above = 428 kW

3rd step = 1.5 X above = 642 kW

4th step = 2.0 X above = 856 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

948 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 690 kBtuh = 138 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 5.0

HEATING SEASON: Months in season = 5.0

Low step multiplier = 6.667/months in season = 1.333

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.416	0	0	0
Low	0.167	429	160	0
Medium	0.167	858	320	0
High	0.083	1288	480	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

SWESTDIV SPREADSHEET INPUTS

COOLING: Months in season = 2.0

Low step multiplier = 6.667/months in season = 3.333

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.067	274	X 3.333	X 1/10.36	= 88
Med	0.067	274	X 3.333	X 2/10.36	= 176
High	0.033	274	X 3.333	X 3/10.36	= 264

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	663	250	663	1020	250	24
Med	1327	500	840	1292	987	95
High	1990	750	840	1292	1900	183

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

COGEN ELEC. CAP., kW		0	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		214		428		642		856	
SHOULDER									
fY heat,	nd	0.416	214	312	428	468	642	468	856
CgB Ht Ld, kBtuh	0	948	1382	948	1036	948	691	948	345
RoB Ht Ld, kBtuh	948	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh	429	1537	899	1537	675	1537	450	1537	225
RoB Ht Ld, kBtuh	1108	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, MED									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh	858	2126	1244	2126	933	2126	622	2126	311
RoB Ht Ld, kBtuh	1268	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
HEATING, HIGH									
fY heat,	nd	0.083	214	62	428	93	642	93	856
CgB Ht Ld, kBtuh	1288	2716	790	2716	592	2716	395	2716	197
RoB Ht Ld, kBtuh	1428	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, LOW									
fY heat,	nd	0.067	302	71	516	91	730	86	944
CgB Ht Ld, kBtuh	0	948	223	948	167	948	111	948	56
RoB Ht Ld, kBtuh	948	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	88	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, MED									
fY heat,	nd	0.067	390	92	604	106	818	96	1032
CgB Ht Ld, kBtuh	0	948	223	948	167	948	111	948	56
RoB Ht Ld, kBtuh	948	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	176	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
COOLING, HIGH									
fY heat,	nd	0.033	478	55	692	60	906	52	1120
CgB Ht Ld, kBtuh	0	948	110	948	82	948	55	948	27
RoB Ht Ld, kBtuh	948	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	264	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr	3981				Ebought	MWh/yr	3981	
Hdemand kBtuh	MBtu/yr	12175				Esold	MWh/yr	0	
Ecogen kW	MWh/yr	0				Hboilers	MBtu/yr	12175	
Hcogen kBtuh	MBtu/yr	0							
Hused kBtuh	MBtu/yr	0							

Cogen Heat Cap., kBtuh

0 SWESTDIV, NO COGEN

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec. nd		0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		214		428		642		856	
SHOULDER									
fY heat, nd	0.416	214	312	428	468	642	468	856	312
CgB Ht Ld, kBtuh	0	948	1382	948	1036	948	691	948	345
RoB Ht Ld, kBtuh	948	214	312	428	468	642	468	840	306
RoB AC Elec Ld, kW	0	1005	1465	2010	2197	3015	2197	3944	1437
		0	0	0	0	0	0	0	0
HEATING, LOW									
fY heat, nd	0.167	214	125	428	188	642	188	856	125
CgB Ht Ld, kBtuh	429	1537	899	1537	675	1537	450	1537	225
RoB Ht Ld, kBtuh	1108	214	125	428	188	642	188	840	123
RoB AC Elec Ld, kW	0	1005	588	2010	882	3015	882	3944	577
		429	251	429	188	429	126	429	63
HEATING, MED									
fY heat, nd	0.167	214	125	428	188	642	188	856	125
CgB Ht Ld, kBtuh	858	2126	1244	2126	933	2126	622	2126	311
RoB Ht Ld, kBtuh	1268	214	125	428	188	642	188	840	123
RoB AC Elec Ld, kW	0	1005	588	2010	882	3015	882	3944	577
		858	502	858	377	858	251	858	126
HEATING, HIGH									
fY heat, nd	0.083	214	62	428	93	642	93	856	62
CgB Ht Ld, kBtuh	1288	2716	790	2716	592	2716	395	2716	197
RoB Ht Ld, kBtuh	1428	274	80	428	93	642	93	840	61
RoB AC Elec Ld, kW	0	1288	375	2010	438	3015	438	3944	287
		1288	375	1288	281	1288	187	1288	94
COOLING, LOW									
fY heat, nd	0.067	302	71	516	91	730	86	944	55
CgB Ht Ld, kBtuh	0	948	223	948	167	948	111	948	56
RoB Ht Ld, kBtuh	948	302	71	516	91	730	86	840	49
RoB AC Elec Ld, kW	88	1418	333	2423	427	3428	402	3944	232
		0	0	0	0	0	0	0	0
COOLING, MED									
fY heat, nd	0.067	390	92	604	106	818	96	1032	61
CgB Ht Ld, kBtuh	0	948	223	948	167	948	111	948	56
RoB Ht Ld, kBtuh	948	390	92	604	106	818	96	840	49
RoB AC Elec Ld, kW	176	1831	430	2836	499	3841	451	3944	232
		0	0	0	0	0	0	0	0
COOLING, HIGH									
fY heat, nd	0.033	478	55	692	60	906	52	1120	32
CgB Ht Ld, kBtuh	0	948	110	948	82	948	55	948	27
RoB Ht Ld, kBtuh	948	478	55	692	60	840	49	840	24
RoB AC Elec Ld, kW	264	2245	260	3249	282	3944	228	3944	114
		0	0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		3981		Ebought MWh/yr	41			
Hdemand kBtuh	MBtu/yr		12175		Esold MWh/yr	18			
Ecogen kW	MWh/yr		3957		Hboilers MBtu/yr	9356			
Hcogen kBtuh	MBtu/yr		18581						
Hused kBtuh	MBtu/yr		2819						
Cogen Heat Cap., kBtuh 3944.325 SWESTDIV, NO CHILLERS, NO PROC. HEAT									

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		214		428		642		856	
SHOULDER									
fY heat,	nd	0.416	214	312	428	468	642	468	856
CgB Ht Ld, kBtuh	0	948	1382	948	1036	948	691	948	345
RoB Ht Ld, kBtuh	948	214	312	428	468	642	468	840	306
RoB AC Elec Ld, kW	0	1005	1465	2010	2197	3015	2197	3944	1437
		0	0	0	0	0	0	0	0
HEATING, LOW									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh	429	1537	899	1537	675	1537	450	1537	225
RoB Ht Ld, kBtuh	1108	214	125	428	188	642	188	840	123
RoB AC Elec Ld, kW	0	1005	588	2010	882	3015	882	3944	577
		429	251	429	188	429	126	429	63
HEATING, MED									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh	858	2126	1244	2126	933	2126	622	2126	311
RoB Ht Ld, kBtuh	1268	214	125	428	188	642	188	840	123
RoB AC Elec Ld, kW	0	1005	588	2010	882	3015	882	3944	577
		858	502	858	377	858	251	858	126
HEATING, HIGH									
fY heat,	nd	0.083	214	62	428	93	642	93	856
CgB Ht Ld, kBtuh	1288	2716	790	2716	592	2716	395	2716	197
RoB Ht Ld, kBtuh	1428	274	80	428	93	642	93	840	61
RoB AC Elec Ld, kW	0	1288	375	2010	438	3015	438	3944	287
		1288	375	1288	281	1288	187	1288	94
COOLING, LOW									
fY heat,	nd	0.067	238	56	452	80	666	78	880
CgB Ht Ld, kBtuh	1020	1968	462	1968	347	1968	231	1968	116
RoB Ht Ld, kBtuh	948	238	56	452	80	666	78	840	49
RoB AC Elec Ld, kW	24	1118	262	2122	374	3127	367	3944	232
		1020	239	1020	180	1020	120	1020	60
COOLING, MED									
fY heat,	nd	0.067	309	73	523	92	737	87	951
CgB Ht Ld, kBtuh	1292	2240	526	2240	394	2240	263	2240	131
RoB Ht Ld, kBtuh	948	309	73	523	92	737	87	840	49
RoB AC Elec Ld, kW	95	1451	341	2456	432	3461	406	3944	232
		1292	303	1292	227	1292	152	1292	76
COOLING, HIGH									
fY heat,	nd	0.033	397	46	611	53	825	48	1039
CgB Ht Ld, kBtuh	1292	2240	259	2240	194	2240	130	2240	65
RoB Ht Ld, kBtuh	948	397	46	611	53	825	48	840	24
RoB AC Elec Ld, kW	183	1864	216	2869	249	3874	224	3944	114
		1292	149	1292	112	1292	75	1292	37
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		3872		Ebought MWh/yr		26		
Hdemand kBtuh	MBtu/yr		13905		Esold MWh/yr		18		
Ecogen kW	MWh/yr		3863		Hboilers MBtu/yr		9356		
Hcogen kBtuh	MBtu/yr		18140						
Hused kBtuh	MBtu/yr		4550						

Cogen Heat Cap., kBtuh 3944.325 SWESTDIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		214		428		642		856	
SHOULDER									
fY heat,	nd	0.416	214	312	428	468	642	468	856
CgB Ht Ld, kBtuh		138	948	1382	948	1036	948	691	948
RoB Ht Ld, kBtuh		810	214	312	428	468	642	468	840
RoB AC Elec Ld, kW		0	1005	1465	2010	2197	3015	2197	3944
			138	201	138	151	138	101	138
HEATING, LOW									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh		567	1537	899	1537	675	1537	450	1537
RoB Ht Ld, kBtuh		970	214	125	428	188	642	188	840
RoB AC Elec Ld, kW		0	1005	588	2010	882	3015	882	3944
			567	332	567	249	567	166	567
HEATING, MED									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh		996	2126	1244	2126	933	2126	622	2126
RoB Ht Ld, kBtuh		1130	214	125	428	188	642	188	840
RoB AC Elec Ld, kW		0	1005	588	2010	882	3015	882	3944
			996	583	996	437	996	291	996
HEATING, HIGH									
fY heat,	nd	0.083	214	62	428	93	642	93	856
CgB Ht Ld, kBtuh		1426	2716	790	2716	592	2716	395	2716
RoB Ht Ld, kBtuh		1290	304	88	428	93	642	93	840
RoB AC Elec Ld, kW		0	1426	415	2010	438	3015	438	3944
			1426	415	1426	311	1426	207	1426
COOLING, LOW									
fY heat,	nd	0.067	302	71	516	91	730	86	944
CgB Ht Ld, kBtuh		138	948	223	948	167	948	111	948
RoB Ht Ld, kBtuh		810	302	71	516	91	730	86	840
RoB AC Elec Ld, kW		88	1418	333	2423	427	3428	402	3944
			138	32	138	24	138	16	138
COOLING, MED									
fY heat,	nd	0.067	390	92	604	106	818	96	1032
CgB Ht Ld, kBtuh		138	948	223	948	167	948	111	948
RoB Ht Ld, kBtuh		810	390	92	604	106	818	96	840
RoB AC Elec Ld, kW		176	1831	430	2836	499	3841	451	3944
			138	32	138	24	138	16	138
COOLING, HIGH									
fY heat,	nd	0.033	478	55	692	60	906	52	1120
CgB Ht Ld, kBtuh		138	948	110	948	82	948	55	948
RoB Ht Ld, kBtuh		810	478	55	692	60	840	49	840
RoB AC Elec Ld, kW		264	2245	260	3249	282	3944	228	3944
			138	16	138	12	138	8	138
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr			3981		Ebought	MWh/yr	41	
Hdemand kBtuh	MBtu/yr			12175		Esold	MWh/yr	26	
Ecogen kW	MWh/yr			3966		Hboilers	MBtu/yr	8147	
Hcogen kBtuh	MBtu/yr			18621					
Hused kBtuh	MBtu/yr			4028					

Cogen Heat Cap., kBtuh 3944.325 SWESTDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1	
All Base nonAC Elec Ld, kW		214		428		642		856	
SHOULDER									
fY heat,	nd	0.416	214	312	428	468	642	468	856
CgB Ht Ld, kBtuh		138	948	1382	948	1036	948	691	948
RoB Ht Ld, kBtuh		810	214	312	428	468	642	468	840
RoB AC Elec Ld, kW		0	1005	1465	2010	2197	3015	2197	3944
			138	201	138	151	138	101	138
HEATING, LOW									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh		567	1537	899	1537	675	1537	450	1537
RoB Ht Ld, kBtuh		970	214	125	428	188	642	188	840
RoB AC Elec Ld, kW		0	1005	588	2010	882	3015	882	3944
			567	332	567	249	567	166	567
HEATING, MED									
fY heat,	nd	0.167	214	125	428	188	642	188	856
CgB Ht Ld, kBtuh		996	2126	1244	2126	933	2126	622	2126
RoB Ht Ld, kBtuh		1130	214	125	428	188	642	188	840
RoB AC Elec Ld, kW		0	1005	588	2010	882	3015	882	3944
			996	583	996	437	996	291	996
HEATING, HIGH									
fY heat,	nd	0.083	214	62	428	93	642	93	856
CgB Ht Ld, kBtuh		1426	2716	790	2716	592	2716	395	2716
RoB Ht Ld, kBtuh		1290	304	88	428	93	642	93	840
RoB AC Elec Ld, kW		0	1426	415	2010	438	3015	438	3944
			1426	415	1426	311	1426	207	1426
COOLING, LOW									
fY heat,	nd	0.067	238	56	452	80	666	78	880
CgB Ht Ld, kBtuh		1158	1968	462	1968	347	1968	231	1968
RoB Ht Ld, kBtuh		810	247	58	452	80	666	78	840
RoB AC Elec Ld, kW		24	1158	272	2122	374	3127	367	3944
			1158	272	1158	204	1158	136	1158
COOLING, MED									
fY heat,	nd	0.067	309	73	523	92	737	87	951
CgB Ht Ld, kBtuh		1430	2240	526	2240	394	2240	263	2240
RoB Ht Ld, kBtuh		810	309	73	523	92	737	87	840
RoB AC Elec Ld, kW		95	1451	341	2456	432	3461	406	3944
			1430	336	1430	252	1430	168	1430
COOLING, HIGH									
fY heat,	nd	0.033	397	46	611	53	825	48	1039
CgB Ht Ld, kBtuh		1430	2240	259	2240	194	2240	130	2240
RoB Ht Ld, kBtuh		810	397	46	611	53	825	48	840
RoB AC Elec Ld, kW		183	1864	216	2869	249	3874	224	3944
			1430	165	1430	124	1430	83	1430
EACH BLOCK		WHOLE SYSTEM							
Edemand kW	MWh/yr		3872			Ebought	MWh/yr	26	
Hdemand kBtuh	MBtu/yr		13905			Esold	MWh/yr	28	
Ecogen kW	MWh/yr		3874			Hboilers	MBtu/yr	8147	
Hcogen kBtuh	MBtu/yr		18190						
Hused kBtuh	MBtu/yr		5759						

Cogen Heat Cap., kBtuh 3944.325 SWESTDIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

# of Buildings:	Large Building 7	Small Building 9	Total for Site (1)	Units	Number of 10 ton Absorption Chillers per cogen unit
Heating Demand:	Diversity	Factor =	50%		
5 Month Season					
Annual Energy:	403	117	3873	MBtu	
Annual Peak:	245	71	2094	kBtuh	
Cooling Demand:	Diversity	Factor =	50%		
2 Month Season					
Annual Energy:	249	73	2396	MBtu	
Annual Peak:	379	110	3238	kBtuh	
Capacity	31.6	9.2	270	tons with	0
Requirement	21.6	9.2	na	tons	1
	11.6	9.2	na	tons	2
	1.6	9.2	na	tons	3
Electric Demand with EER 10.36 Btu/Wh, DF= 50%					
There are	0.8	0.8	0.8	0.4	months
when P(AC)=	48.6	136.6	224.6	312.6	0
(in kW)	48.6	58.8	146.8	234.8	1
	48.6	48.6	69.0	157.0	2
	48.6	48.6	48.6	79.3	3
Non-AC Electric:	Large	Small	Total		DF= 50%
Annual Energy	390	114	3753	MWh	
Peak Demand:	111	32	975	kW for	9.2 months
Total Electric Demand DF= 0%					
There are	0.8	0.8	0.8	0.4	months
when P(tot)=	975	1063	1151	1239	0
(in kW)	975	985	1073	1161	1
	975	975	996	1084	2
	975	975	975	1006	3
Utility Demand with 9 120 kW cogenerators:					
There are	0.8	0.8	0.8	0.4	months
when P(tot)=	0	0	71	159	0 and
(in kW)	0	0	0	81	1 5
	0	0	0	4	2 with
	0	0	0	0	3 0
1 See discussion of diversity in text.					

Demand Table - SWESTDIV

PACDIV SPREADSHEET INPUTS

ELECTRIC: Whole Base Non AC Avg. Load = 561 kW

Low step = 0.5 X above = 280 kW

2nd step = 1.0 X above = 561 kW

3rd step = 1.5 X above = 842 kW

4th step = 2.0 X above = 1122 kW

PROCESS HEAT: If no process heat is obtained from cogeneration, then add the Hourly Average Process Heat for Whole Site, or

1003 kBtuh

to the "RoB Ht Ld" in the spreadsheet for all heating, cooling, and shoulder seasons. If 20% of process heat in cogenerated buildings is carried by cogenerators, then add 0.2 X Hourly Average Process Heat for 7 Buildings, or

0.2 X 730 kBtuh = 146 kBtuh

to all "CgB Ht Ld" inputs for all seasons, and reduce the "RoB Ht Ld" by the same amount, below what it was in the former case.

SHOULDER SEASON: Months in season = 5.0

HEATING SEASON: Months in season = 1.0

Low step multiplier = 6.667/months in season = 6.667

Cogenerated Buildings Heat Load and Rest of Buildings Heat Load, Due to Space Heating Only (Not Including Process Heat)

	fy heat	CgB ht load kBtuh	RoB ht load kBtuh	RoB AC elec kW
Shoulder	0.417	0	0	0
Low	0.033	993	373	0
Medium	0.033	1987	747	0
High	0.017	2980	1120	0

CgB hload = Avg. CgB heat load X low step multiplier X [1,2 or 3]

RoB hload = Avg. RoB heat load X low step multiplier X [1,2 or 3]

PACDIV SPREADSHEET INPUTS

COOLING: Months in season = 6.0

Low step multiplier = 6.667/months in season = 1.111

If no chillers, all base cooling met as "RoB AC Elec Ld"

	fy cool	All Base Avg Cooling Load kBtuh	Low Step Multiplier		RoB AC elec kW
Low	0.200	807	X 1.111	X 1/10.36	= 87
Med	0.200	807	X 1.111	X 2/10.36	= 173
High	0.100	807	X 1.111	X 3/10.36	= 260

If one chiller per cogenerator, the chillers meet as much of the cooling load as they can. Any excess, together with non-cogenerated building cooling load, is met electrically

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chillers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	652	244	652	1003	244	24
Med	1304	489	840	1292	953	92
High	1956	733	840	1292	1849	178

7 bldgs. cooling load = avg. 7 bldgs. cooling load X low step multiplier X [1,2 or 3]

RoB cooling load = rest of site avg. cooling load X low step multiplier X [1,2 or 3]

Met by chillers = lesser of 7 bldgs cooling load and 840 kBtuh

CgB thermal input = met by chillers/0.65

Not met by chillers = 7 bldgs cooling load - met by chillers + RoB cooling load

RoB AC electric = Not met by chillers/10.36

If two chillers per cogenerator, the chillers again meet as much of the cooling load as they can, but now the limit is $2 \times 840 = 1680$ KBtuh of cooling load.

	7 bldgs cooling load kBtuh	RoB cooling load kBtuh	Met by chil-lers kBtuh	CgB thermal input kBtuh	Not met by chlrs. kBtuh	RoB AC elec. kW
Low	652	244	652	1003	244	24
Med	1304	489	1304	2006	489	47
High	1956	733	1680	2585	1009	97

COGEN ELEC. CAP., kW		0	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1		
All Base nonAC Elec Ld, kW		280		561		842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	0	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	1003	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	993	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1376	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1987	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1750	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	2980	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	2123	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
COOLING, LOW										
fY heat,	nd	0.2	367	257	648	341	929	326	1209	212
CgB Ht Ld, kBtuh	0	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	1003	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	87	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
COOLING, MED										
fY heat,	nd	0.2	453	317	734	386	1015	356	1295	227
CgB Ht Ld, kBtuh	0	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	1003	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	173	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
COOLING, HIGH										
fY heat,	nd	0.1	540	189	821	216	1102	193	1382	121
CgB Ht Ld, kBtuh	0	1003	351	1003	264	1003	176	1003	88	
RoB Ht Ld, kBtuh	1003	0	0	0	0	0	0	0	0	0
RoB AC Elec Ld, kW	260	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr		5597		Ebought	MWh/yr	5597			
Hdemand kBtuh	MBtu/yr		10582		Esold	MWh/yr	0			
Ecogen kW	MWh/yr		0		Hboilers	MBtu/yr	10582			
Hcogen kBtuh	MBtu/yr		0							
Hused kBtuh	MBtu/yr		0							
Cogen Heat Cap., kBtuh		0 PACDIV, NO COGEN								

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1		
All Base nonAC Elec Ld, kW		280		561		842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	0	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	1003	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	993	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1376	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		993	115	993	86	993	57	993	29	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1987	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1750	423	49	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1987	230	2634	228	3944	228	3944	114	
		1987	230	1987	172	1987	115	1987	57	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	2980	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	2123	635	38	635	28	840	25	840	13	
RoB AC Elec Ld, kW	0	2980	178	2980	133	3944	117	3944	59	
		2980	178	2980	133	2980	89	2980	44	
COOLING, LOW										
fY heat,	nd	0.2	367	257	648	341	929	326	1209	212
CgB Ht Ld, kBtuh	0	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	1003	367	257	648	341	840	294	840	147	
RoB AC Elec Ld, kW	87	1723	1208	3043	1599	3944	1382	3944	691	
		0	0	0	0	0	0	0	0	
COOLING, MED										
fY heat,	nd	0.2	453	317	734	386	1015	356	1295	227
CgB Ht Ld, kBtuh	0	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	1003	453	317	734	386	840	294	840	147	
RoB AC Elec Ld, kW	173	2127	1491	3447	1812	3944	1382	3944	691	
		0	0	0	0	0	0	0	0	
COOLING, HIGH										
fY heat,	nd	0.1	540	189	821	216	1102	193	1382	121
CgB Ht Ld, kBtuh	0	1003	351	1003	264	1003	176	1003	88	
RoB Ht Ld, kBtuh	1003	540	189	821	216	840	147	840	74	
RoB AC Elec Ld, kW	260	2536	888	3855	1013	3944	691	3944	346	
		0	0	0	0	0	0	0	0	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr			5597		Ebought	MWh/yr	456		
Hdemand kBtuh	MBtu/yr			10582		Esold	MWh/yr	41		
Ecogen kW	MWh/yr			5182		Hboilers	MBtu/yr	9277		
Hcogen kBtuh	MBtu/yr			24334						
Hused kBtuh	MBtu/yr			1305						

Cogen Heat Cap., kBtuh 3944.325 PACDIV, NO CHILLERS, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		280	561			842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	0	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	1003	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	993	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1376	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		993	115	993	86	993	57	993	29	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1987	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1750	423	49	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1987	230	2634	228	3944	228	3944	114	
		1987	230	1987	172	1987	115	1987	57	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	2980	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	2123	635	38	635	28	840	25	840	13	
RoB AC Elec Ld, kW	0	2980	178	2980	133	3944	117	3944	59	
		2980	178	2980	133	2980	89	2980	44	
COOLING, LOW										
fY heat,	nd	0.2	304	213	585	307	866	303	1146	201
CgB Ht Ld, kBtuh	1003	2006	1406	2006	1054	2006	703	2006	351	
RoB Ht Ld, kBtuh	1003	304	213	585	307	840	294	840	147	
RoB AC Elec Ld, kW	24	1427	1000	2747	1444	3944	1382	3944	691	
		1003	703	1003	527	1003	351	1003	176	
COOLING, MED										
fY heat,	nd	0.2	372	261	653	343	934	327	1214	213
CgB Ht Ld, kBtuh	1292	2295	1608	2295	1206	2295	804	2295	402	
RoB Ht Ld, kBtuh	1003	372	261	653	343	840	294	840	147	
RoB AC Elec Ld, kW	92	1747	1224	3066	1612	3944	1382	3944	691	
		1292	905	1292	679	1292	453	1292	226	
COOLING, HIGH										
fY heat,	nd	0.1	458	160	739	194	1020	179	1300	114
CgB Ht Ld, kBtuh	1292	2295	804	2295	603	2295	402	2295	201	
RoB Ht Ld, kBtuh	1003	458	160	739	194	840	147	840	74	
RoB AC Elec Ld, kW	178	2151	754	3470	912	3944	691	3944	346	
		1292	453	1292	340	1292	226	1292	113	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	5273			Ebought	MWh/yr	358			
Hdemand kBtuh	MBtu/yr	15735			Esold	MWh/yr	41			
Ecogen kW	MWh/yr	4955			Hboilers	MBtu/yr	9277			
Hcogen kBtuh	MBtu/yr	23268								
Hused kBtuh	MBtu/yr	6458								

Cogen Heat Cap., kBtuh 3944.325 PACDIV, 1 CHILLER/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4	0.3		0.2		0.1			
All Base nonAC Elec Ld, kW		280	561		842		1122			
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	0	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	1003	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		0	0	0	0	0	0	0	0	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	993	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1376	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		993	115	993	86	993	57	993	29	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1987	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1750	423	49	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1987	230	2634	228	3944	228	3944	114	
		1987	230	1987	172	1987	115	1987	57	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	2980	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	2123	635	38	635	28	840	25	840	13	
RoB AC Elec Ld, kW	0	2980	178	2980	133	3944	117	3944	59	
		2980	178	2980	133	2980	89	2980	44	
COOLING, LOW										
fY heat,	nd	0.2	304	213	585	307	866	303	1146	201
CgB Ht Ld, kBtuh	1003	2006	1406	2006	1054	2006	703	2006	351	
RoB Ht Ld, kBtuh	1003	304	213	585	307	840	294	840	147	
RoB AC Elec Ld, kW	24	1427	1000	2747	1444	3944	1382	3944	691	
		1003	703	1003	527	1003	351	1003	176	
COOLING, MED										
fY heat,	nd	0.2	327	229	608	320	889	312	1169	205
CgB Ht Ld, kBtuh	2006	3009	2109	3009	1582	3009	1054	3009	527	
RoB Ht Ld, kBtuh	1003	427	299	608	320	840	294	840	147	
RoB AC Elec Ld, kW	47	2006	1406	2855	1501	3944	1382	3944	691	
		2006	1406	2006	1054	2006	703	2006	351	
COOLING, HIGH										
fY heat,	nd	0.1	377	132	658	173	939	165	1219	107
CgB Ht Ld, kBtuh	2585	3588	1257	3588	943	3588	629	3588	314	
RoB Ht Ld, kBtuh	1003	551	193	658	173	840	147	840	74	
RoB AC Elec Ld, kW	97	2585	906	3090	812	3944	691	3944	346	
		2585	906	2585	679	2585	453	2585	226	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	5123		Ebought	MWh/yr	313			
Hdemand	kBtuh	MBtu/yr	18118		Esold	MWh/yr	172			
Ecogen	kW	MWh/yr	4981		Hboilers	MBtu/yr	9277			
Hcogen	kBtuh	MBtu/yr	23391							
Hused	kBtuh	MBtu/yr	8841							

Cogen Heat Cap., kBtuh 3944.325 PACDIV, 2 CHILLERS/COGEN, NO PROC. HEAT

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd		1.375					
frac. of Year Elec.	nd	0.4		0.3		0.2		0.1		
All Base nonAC Elec Ld, kW		280		561		842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	146	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	857	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		146	213	146	160	146	107	146	53	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1139	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1230	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		1139	132	1139	99	1139	66	1139	33	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	2133	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1604	454	53	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	2133	247	2634	228	3944	228	3944	114	
		2133	247	2133	185	2133	123	2133	62	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	3126	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	1977	666	40	666	30	840	25	840	13	
RoB AC Elec Ld, kW	0	3126	186	3126	140	3944	117	3944	59	
		3126	186	3126	140	3126	93	3126	47	
COOLING, LOW										
fY heat,	nd	0.2	367	257	648	341	929	326	1209	212
CgB Ht Ld, kBtuh	146	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	857	367	257	648	341	840	294	840	147	
RoB AC Elec Ld, kW	87	1723	1208	3043	1599	3944	1382	3944	691	
		146	102	146	77	146	51	146	26	
COOLING, MED										
fY heat,	nd	0.2	453	317	734	386	1015	356	1295	227
CgB Ht Ld, kBtuh	146	1003	703	1003	527	1003	351	1003	176	
RoB Ht Ld, kBtuh	857	453	317	734	386	840	294	840	147	
RoB AC Elec Ld, kW	173	2127	1491	3447	1812	3944	1382	3944	691	
		146	102	146	77	146	51	146	26	
COOLING, HIGH										
fY heat,	nd	0.1	540	189	821	216	1102	193	1382	121
CgB Ht Ld, kBtuh	146	1003	351	1003	264	1003	176	1003	88	
RoB Ht Ld, kBtuh	857	540	189	821	216	840	147	840	74	
RoB AC Elec Ld, kW	260	2536	888	3855	1013	3944	691	3944	346	
		146	51	146	38	146	26	146	13	
EACH BLOCK		WHOLE SYSTEM								
Edemand kW	MWh/yr	5597			Ebought	MWh/yr	456			
Hdemand kBtuh	MBtu/yr	10582			Esold	MWh/yr	48			
Ecogen kW	MWh/yr	5189			Hboilers	MBtu/yr	7998			
Hcogen kBtuh	MBtu/yr	24366								
Hused kBtuh	MBtu/yr	2584								

Cogen Heat Cap., kBtuh 3944.325 PACDIV, NO CHILLERS, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		280	561			842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	146	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	857	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		146	213	146	160	146	107	146	53	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1139	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1230	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		1139	132	1139	99	1139	66	1139	33	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	2133	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1604	454	53	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	2133	247	2634	228	3944	228	3944	114	
		2133	247	2133	185	2133	123	2133	62	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	3126	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	1977	666	40	666	30	840	25	840	13	
RoB AC Elec Ld, kW	0	3126	186	3126	140	3944	117	3944	59	
		3126	186	3126	140	3126	93	3126	47	
COOLING, LOW										
fY heat,	nd	0.2	304	213	585	307	866	303	1146	201
CgB Ht Ld, kBtuh	1149	2006	1406	2006	1054	2006	703	2006	351	
RoB Ht Ld, kBtuh	857	304	213	585	307	840	294	840	147	
RoB AC Elec Ld, kW	24	1427	1000	2747	1444	3944	1382	3944	691	
		1149	805	1149	604	1149	403	1149	201	
COOLING, MED										
fY heat,	nd	0.2	372	261	653	343	934	327	1214	213
CgB Ht Ld, kBtuh	1438	2295	1608	2295	1206	2295	804	2295	402	
RoB Ht Ld, kBtuh	857	372	261	653	343	840	294	840	147	
RoB AC Elec Ld, kW	92	1747	1224	3066	1612	3944	1382	3944	691	
		1438	1008	1438	756	1438	504	1438	252	
COOLING, HIGH										
fY heat,	nd	0.1	458	160	739	194	1020	179	1300	114
CgB Ht Ld, kBtuh	1438	2295	804	2295	603	2295	402	2295	201	
RoB Ht Ld, kBtuh	857	458	160	739	194	840	147	840	74	
RoB AC Elec Ld, kW	178	2151	754	3470	912	3944	691	3944	346	
		1438	504	1438	378	1438	252	1438	126	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	5273			Ebought	MWh/yr	358		
Hdemand	kBtuh	MBtu/yr	15735			Esold	MWh/yr	48		
Ecogen	kW	MWh/yr	4962			Hboilers	MBtu/yr	7998		
Hcogen	kBtuh	MBtu/yr	23300							
Hused	kBtuh	MBtu/yr	7737							

Cogen Heat Cap., kBtuh 3944.325 PACDIV, 1 CHILLER/COGEN, 20% PROC. HEAT IN CgB

COGEN ELEC. CAP., kW		840	HEAT/ELEC. RATIO, nd			1.375				
frac. of Year Elec.	nd	0.4	0.3			0.2		0.1		
All Base nonAC Elec Ld, kW		280	561			842		1122		
SHOULDER										
fY heat,	nd	0.417	280	409	561	615	842	615	1122	410
CgB Ht Ld, kBtuh	146	1003	1466	1003	1099	1003	733	1003	366	
RoB Ht Ld, kBtuh	857	280	409	561	615	840	614	840	307	
RoB AC Elec Ld, kW	0	1315	1921	2634	2887	3944	2882	3944	1441	
		146	213	146	160	146	107	146	53	
HEATING, LOW										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	1139	2369	274	2369	205	2369	137	2369	68	
RoB Ht Ld, kBtuh	1230	280	32	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	1315	152	2634	228	3944	228	3944	114	
		1139	132	1139	99	1139	66	1139	33	
HEATING, MED										
fY heat,	nd	0.033	280	32	561	49	842	49	1122	32
CgB Ht Ld, kBtuh	2133	3737	432	3737	324	3737	216	3737	108	
RoB Ht Ld, kBtuh	1604	454	53	561	49	840	49	840	24	
RoB AC Elec Ld, kW	0	2133	247	2634	228	3944	228	3944	114	
		2133	247	2133	185	2133	123	2133	62	
HEATING, HIGH										
fY heat,	nd	0.017	280	17	561	25	842	25	1122	17
CgB Ht Ld, kBtuh	3126	5103	304	5103	228	5103	152	5103	76	
RoB Ht Ld, kBtuh	1977	666	40	666	30	840	25	840	13	
RoB AC Elec Ld, kW	0	3126	186	3126	140	3944	117	3944	59	
		3126	186	3126	140	3126	93	3126	47	
COOLING, LOW										
fY heat,	nd	0.2	304	213	585	307	866	303	1146	201
CgB Ht Ld, kBtuh	1149	2006	1406	2006	1054	2006	703	2006	351	
RoB Ht Ld, kBtuh	857	304	213	585	307	840	294	840	147	
RoB AC Elec Ld, kW	24	1427	1000	2747	1444	3944	1382	3944	691	
		1149	805	1149	604	1149	403	1149	201	
COOLING, MED										
fY heat,	nd	0.2	327	229	608	320	889	312	1169	205
CgB Ht Ld, kBtuh	2152	3009	2109	3009	1582	3009	1054	3009	527	
RoB Ht Ld, kBtuh	857	458	321	608	320	840	294	840	147	
RoB AC Elec Ld, kW	47	2152	1508	2855	1501	3944	1382	3944	691	
		2152	1508	2152	1131	2152	754	2152	377	
COOLING, HIGH										
fY heat,	nd	0.1	377	132	658	173	939	165	1219	107
CgB Ht Ld, kBtuh	2731	3588	1257	3588	943	3588	629	3588	314	
RoB Ht Ld, kBtuh	857	582	204	658	173	840	147	840	74	
RoB AC Elec Ld, kW	97	2731	957	3090	812	3944	691	3944	346	
		2731	957	2731	718	2731	478	2731	239	
EACH BLOCK		WHOLE SYSTEM								
Edemand	kW	MWh/yr	5123			Ebought	MWh/yr	313		
Hdemand	kBtuh	MBtu/yr	18118			Esold	MWh/yr	212		
Ecogen	kW	MWh/yr	5021			Hboilers	MBtu/yr	7998		
Hcogen	kBtuh	MBtu/yr	23577							
Hused	kBtuh	MBtu/yr	10120							

Cogen Heat Cap., kBtuh 3944.325 PACDIV, 2 CHILLERS/COGEN, 20% PROC. HEAT IN CgB

APPENDIX C: Test of MCC 85 Kw cogenerator

In preparing our proposals and program plans, we had used as a baseline the cogeneration system designed and marketed by our industrial partner, Modular Cogeneration Corporation ("MCC"), which they call the "Smart-1". The Smart-1 is designed around a six cylinder Fiat industrial diesel engine, and incorporates the primary advance identified in Chapter 2 - a reliance on a heavy-duty, high compression engine to provide high efficiency in the production of valuable electrical power. Because MCC's specifications for the machine go beyond any other generation units available in the regime below 100 kW, it was necessary to verify these claims. As part of our preparation of a program plan, we planned an independent test of the performance and emissions of the Smart-1 system, testing a machine installed at MCC's facility in New Holland, PA. The protocols and results are presented in this chapter after a brief description of the Smart-1 itself. In summary, the test produced only limited data, since the machine over heated and the coolant blew out a major heat exchanger before full power operations could be monitored.

C.1 The Smart-1 Cogeneration System

This six-liter engine, naturally aspirated with a 17:1 compression ratio, should be capable of mechanical efficiencies approaching 40% with low environmental emissions when operated in the dual fuel mode. The system is described by a block diagram in Figure A-1. The fuel supply system is simple, with diesel fuel metered into the fuel injectors at a rate sufficient to maintain idle operation, while natural gas or propane is metered directly into the air intake to provide the bulk of the energy content of the fuel. The system requires a small amount of diesel fuel for ignition, so it cannot operate on 100% gas, but it can revert to 100% diesel fuel operation if desired. This would produce an increase in emissions levels, but we did not test under these circumstances.

The Smart-1 is available with either an induction or a synchronous generator. An induction generator results in a simpler system, since it automatically provides power in phase with that of the local utility, and the generator can also serve as an induction motor to start the cogenerator, allowing elimination of the twelve-volt DC starter/generator subsystem. However, the induction generator cannot run in a stand-alone mode, so if the local utility has a black-out, the cogeneration system will also. The induction generator also cannot improve the power factor above that of the local utility, so if reactive power is present on the line, that inefficiency will be present in the cogenerated power as well. Consequently, MCC prefers the synchronous generator option in most circumstances, and the system we tested had a 100 ampere, 480 volt (83 kW) Newage synchronous generator, directly connected to the local utility.

The Smart-1 uses heat both from the jacket cooling water (with or without an isolating heat exchanger, depending on the application) and from the water-cooled exhaust manifold in the same circuit. Additionally, if a domestic hot water load is available, a stainless steel condensing heat exchanger at the end of the exhaust system preheats the cold water and condenses most of the water out of the exhaust stream, contributing to lowered emissions.

Figure C-1: Smart-1 Block Diagram.

Several other features should contribute ease of use and efficient operation. The entire system is inside a sealed, sound-insulated container which will easily fit through standard doors and into elevators. Incoming air is used to cool the generator, so this heat ends up back in the engine and is recovered in the water circuits, allowing an overall recovery of 90-95% of the energy content of the fuel if appropriate hot water loads are present.

Plans also call for the incorporation of an on-board computer which will monitor many functions and analyse them for signs of problems, calling for help over a modem if trouble arises. We supplied our own instrumentation, and did not test this feature of the machine.

C.2 Test Protocols and Equipment

The testing was carried out entirely using equipment brought from BNL. The electrical efficiency was the quantity of primary interest, with emissions and thermal efficiency also closely monitored. The following sub-sections discuss the methods and equipment used for each physical quantity.

C.2.1 Electrical Power.

The installed system feeds back to the local utility through a standard Sagamon electric meter which has been recently calibrated. Although these are usually quite accurate, we preferred to maintain the independence of our testing by bringing our Dranetz Series 808 Electric Power Demand Analyser. This is a self-contained system incorporating current transformers and voltage probes and true RMS measuring circuitry. It can measure power, current, voltages, power factors, phase angles and all related quantities on up to three active phases. The results are accurate to 1/4% and are NIST (NBS) traceable; the unit had been factory calibrated three months before the tests. The Dranetz also incorporates a substantial memory and an input/output port allowing control by and data export to an external computer. The system was programmed to monitor power flows in detail once every minute for the duration of our tests.

C.2.2 Fuel Inputs

Diesel oil is consumed at a rate of about 20 ml (0.7 oz) per minute. Fuel was monitored by setting the fuel vessel on a Sartorius 3802MP digital scale, readable to 0.1 g, accurate to 0.1-0.3g, with a capacity of 6 kg. Care was taken that the weight of the flexible fuel line stayed constant throughout the experiment, and the mass of the fuel container was recorded at the beginning and end of each timed run, giving the mass of the fuel consumed during the run.

Natural gas is not available at the MCC facility, so the system is normally operated on LPG from a 500 gallon tank, with fuel supplied by a local dealer. At full load, the system consumes about 40 liters per minute (1.5 cfm) of fuel, monitored by a bellows type gas meter on the line. We used this supply for all tune-up and acclimatization runs reported here.

Uncertainty about the precise fractions of non-propane fuel gases in the LPG and about the calibration of the meter led us to purchase cylinders of chemically pure (less than 1% impurities) propane. Since the impurities are propylene and other fuel gases, this results in an uncertainty in the energy content well below 1%. Also, rather than rely on the gas meter, the primary data on propane consumption was to be taken by setting the propane cylinder on a 1000 lb scale, readable to 0.1 lb. This would have allowed very accurate determinations of system efficiency, but unfortunately the engine failed before we could use this method.

In most applications the Smart-1 will run on a combination of diesel fuel and natural gas, so to eliminate any chance that its performance on propane might differ from that on natural gas, we also purchased a cylinder of chemically pure methane, enough to run the system for about one-half hour. (The Smart-1 requires about 4 cfm of methane at full load.) The setup is the same as for chemically pure propane, measuring weight change as methane is withdrawn from the 120 lb cylinder. Again, we did not get an opportunity to initiate these tests.

C.2.3 Exhaust emission Measurements

In measuring engine exhaust emissions a dilution tunnel approach was taken, as illustrated in Figure A-2. Exhaust gas from the engine system condensing economizer is divided into two parts. One part, about 80% of the gas, is simply vented through PVC pipe. The other portion goes to the dilution tunnel where it is mixed with filtered ambient air at a ratio of about 5/1 (air/gas). The dilution tunnel was constructed of 6" diameter stainless steel ducting and the total tunnel length was 10'. In sampling for particulates the dilution tunnel provides two advantages. First, particulates are mixed with ambient air, simulating the types of processes which occur when raw diesel exhaust is normally vented. This includes the condensation of semi-volatile organics and other compounds on the particulates. A second advantage of the dilution tunnel is the elimination of engine pressure pulsations at the point of sampling. In the dilution tunnel the flow Reynolds number was typically about 30,000 and the exhaust gas was injected in a direction opposite to the bulk flow. Both of these points promote mixing of gas and dilution air early in the tunnel.

In particulate sampling a metered portion of the diluted exhaust gas was drawn through a standard, unheated 47 mm quartz filter. To establish the dilution ratio CO_2 measurements were made in the raw and diluted exhaust gas using a non-dispersive infrared analyzer (Rosemont). A condensation type sample gas handler was used to feed clean, dry gas to this analyzer (Clean Air Engineering). A wet-electrochemical cell type gas analyzer (ENERAC E 2000, Energy Efficiency Systems) was used to measure oxygen, carbon monoxide, and NO_x in the dilution tunnel. From the CO_2 levels in the dilution tunnel the concentrations of particulates, CO, and NO_x were converted to a per-unit of fuel and per-unit of output power basis.

C.2.4 Heat Recovery

The engine water jacket heat was easily monitored, since the Smart-1 has fourteen thermistors mounted in the engine water at various points using 3/8" NPT fittings. For the test, we replaced those shown in Figure 3 with Type K thermocouples wired into our Campbell multichannel datalogger. This allowed us to monitor temperatures during the entire process, including warm-up and normal full load operation. The cooling circuit is serial, connecting the water jacket in the block and the water-cooled exhaust manifold as shown in Figure 3, and includes a 55 gallon drum as a reservoir. There is also a radiator, which would normally dissipate thermal power in excess of the demands of the local facility. There is no thermal load at the MCC facility, so the radiator transferred all the engine heat to the atmosphere. Temperature control is accomplished with a throttling valve. We also installed a Ramapo target flow meter into an appropriate point in the water circuit, and fed that signal into the Campbell datalogger as well. The flowmeter had been calibrated in the datalogger at BNL shortly prior to these experiments, using a quadratic relation between the meter's output voltage and the fluid flow rate, and was accurate to better than 1%. A temperature correction for the density of water was also incorporated, eliminating a possible source of a 3-5% error. The thermal power is then the

Figure C-2: Emissions Measurement Apparatus.

product of temperature difference, fluid flow and the heat capacity of water. Temperatures, flows and thermal power were to be recorded every minute by the Campbell datalogger.

There is also a condensing recuperator on the exhaust pipe. In order to condense water in the exhaust stream, this must operate at a substantially lower temperature than the water jacket, and so is only useful to preheat domestic hot water or provide some similar warming function in the sub-100°F (sub-40°C) regime. Here we monitored water temperature in and out of the water side with thermocouples and the flow rate by timing flow into a bucket and measuring the mass accumulated. Thermocouples also measured the temperature of the exhaust in and out on the gas side. The exhaust flow could subsequently be calculated from stoichiometry so that a heat balance could be established. The sum of this condenser heat and the water jacket heat of the previous paragraph constitutes the thermal power output of the Smart-1.

C.3 Test Results - Power and Efficiency

The actual operation of the Smart-1 was carried out by MCC personnel, since they were familiar with its characteristics, while BNL personnel operated the monitoring equipment described above. Two sets of shakedown runs were carried out, one for two hours in the afternoon, after all the equipment had been set up and another the next morning. After about one-half hour of operation in the morning, the engine boiled over and the pressure of the steam ruptured the stainless steel exhaust heat exchanger. It was subsequently determined that the cooling fan which forced air through the radiator had not been turned on manually, as required. There being no possibility of making repairs in less than a few weeks, the experiment was disassembled. The data to be reported below were all derived from the shakedown runs and are therefore somewhat limited.

During the emissions tests, the Smart-1 output was measured at 50.5 kW on the Sagamon meter. (The Dranetz reading was consistent, but it was not yet recording at the time). Simultaneously, a mass measurement indicated that 50 g of oil were consumed in 52.9 s, or 0.945 g/s. Using standard conversions and 19.4-19.7 kBtu/lb of oil, this corresponds to 146-148 kBtu/hr as input energy in the fuel oil.

The MCC gas meter indicated 21.62 s/ft³ of LPG. The supplier's MSDS states that the LPG is 92% propane, 5% propylene and 3% butane. We did not measure the temperature of the LPG at that time, but using STP values for the heats of combustion (2.505, 2.460 and 3.368 kBtu/ft³ respectively) gives 421 mBtu/hr of LPG. This gives a total of 568 mBtu/hr, which corresponds to an efficiency of 30%. This is well below the 38-40% MCC had expected. One reason for the discrepancy is that in order to raise the power output to 85 kW, they increased the engine speed from around 1800 rpm to around 2300 rpm. In addition, the engine was running roughly, and it was subsequently determined that a cylinder sleeve had slipped out of position. Since it is not clear exactly when this happened, it is not possible to be sure if it was a factor.

Although we did take thermal data during these shakedown runs, we have not attempted to process the data since the system never reached thermal steady state and was always running well below rated power. The six thermocouples placed in the exhaust stream from each cylinder gave erratic and very low temperature readings (350-500°F), which we now believe is evidence that the exhaust heat exchanger was already leaking, with water dripping down onto the hot thermocouples.

C.4 Test Results - Emissions Measurements

Due to the technical difficulties at MCC we were forced to reduce every bit of data that we had. This included some very preliminary measurements made using the ENERAC gas analyzer directly in the exhaust pipe at two different load levels as well as the one, more careful, test which included particulates in the dilution tunnel. For the preliminary tests we do not have fuel flow rates which, for emissions calculations, means that we had to estimate the mix of gas and oil actually fired in these tests. The assumption used was that the ratio was the same as in the more careful, dilution tunnel test. The effect that this will have on the accuracy of the data reduction is small because the differences in hydrogen/carbon ratios among the fuels are not that great. The table below provides a summary of the results.

Test Number		1	2	3
Time		5:50 pm	6:50 pm	5:40 pm
Gas sampling point		exhaust pipe	dilution tunnel	exhaust pipe
Power Output	kW	42	50.5	64.5
NO _x	[g/hp-hr]	4.26	4.16	5.68
CO	[g/hp-hr]	9.91	9.14	6.40
particulates	[g/hp-hr]	-	.15	-

Table A-1: Results of Emissions Measurements on Smart-1.

Comparisons with typical expected emissions reported in Table 2-5 above are possible. NO_x for typical dual fuel engines is estimated there at 6 g/hp-hr. The latest version of the EPA's AP-42 listing of expected average emissions lists the emission factor for NO_x for dual fuel engines at 9.1 g/hp-hr. By either of these standards the Smart-1 is performing well. However, for CO, Table 2-5 indicates that 2-3 g/bhp-hr should be expected for a dual-fuel engine with no exhaust controls, and measured performance was quite a bit higher. The only measurement of particulates, 0.15 g/bhp-hr, is the same as the expected value in Table 2-5. Given the

uncertainties of the engine's operation while we were testing it, the Smart-1 appears to be fairly ordinary in its class with respect to emissions.

C.5 System Assessment

The performance of the engine appears to be typical of its class, both with respect to efficiency and emissions. Reliability of the engine tested was well below average, and operation apparently troublesome. At the conclusion of the test MCC reported that this engine was in storage for two years and may have suffered deterioration during that time. In part as a result of these events, we decided to base our assessment of modular cogeneration in the Navy on a unit sold by a different company, one with a larger customer base and which at 120 kW is more appropriately sized to the needs of Navy bases.

APPENDIX D: Cogenerating Fuel Cells

SERDP is funding a demonstration project to determine the applicability of this technology to U.S. military installations. (SERDP ID #641) Because fuel cells are potentially a strong competitor to reciprocating engine cogeneration, we include here a brief summary of the technology and its current and likely future state.

Fuel-cell power generation units provide another option for meeting commercial and industrial electric energy demands as environmentally clean, efficient sources of power and heat.^{1,2} All fuel cells are cogeneration machines by their inherent operation. Fuel cells rely on an electrochemical reaction of hydrogen and oxygen which generates both electricity and heat. Today, the lowest cost source of hydrogen for a fuel cell is through the conversion of natural gas in a catalytic reformer. In a fuel cell hydrogen and oxygen are combined in an electrolyte, an electrically conductive material, such as phosphoric acid. The fuel cell process is nearly twice as efficient as steam turbine power generation because the fuel is processed into electricity through chemical reactions without being combusted. Fuel cells are in a way similar to batteries, but they can operate continuously as long as they have a fuel source. The fuel cell emits carbon-dioxide, the major component, along with very small emissions of nitrogen oxides, carbon-monoxide, and hydrocarbons. The amount of carbon-dioxide is lower than with conventional fuel fired power plants when efficiency factors are taken into account. Fuel cell operation is very quiet and noise is not a site selection criteria problem as with most power generation equipment.

The earliest fuel cell types were based on alkaline electrolytes and are historically linked to manned space flights in the NASA Gemini and Apollo missions. Today, only three basic fuel cell types are considered practical for power generation here on earth. These include phosphoric acid, molten carbonate, and solid oxide.

The three major components in these systems are the fuel processing section, the power section which generates the heat and electrical power, and the power conditioning section. The fuel processor takes in natural gas along with steam and heat from the power section and outputs a hydrogen rich gas to the power section and relatively clean exhaust products. The power section takes in air (oxygen) and the hydrogen rich gas and by the fuel cells chemical reactions results in direct current electric power, water, steam and heat, and again a relatively clean exhaust. The power conditioner converts the direct current into an alternating current, controlling frequency to match the local electric utility system and sends the power onto the utility grid. The excess heat from the fuel cell system is then available for other uses.

The phosphoric acid fuel cell has recently been introduced into the U.S. market by ONSI Corporation, a subsidiary of International Fuel Cells Corp., a subsidiary of United Technologies Corp., which manufactures a 200 kW packaged fuel cell.^{1,3,4} The phosphoric acid fuel cell operates at temperatures up to 400F, with a 36% - 39% electrical efficiency, and 80 percent overall (electric and heat) efficiency. Heat rejection from the ONSI unit is currently at 180F, but a large portion could be extracted at 350F as is the practice with the firms in Japan that are also building systems of this type. The advantages of doing so include

facilitating the interface with building space/water heating systems and the option of using the reject heat to drive heat-activated air conditioning systems such as double effect absorption and desiccant technology. The latter issue is the primary reason the efforts in Japan are to extract the heat at the highest temperature possible. In Japan four companies are commercializing and/or developing phosphoric acid fuel cells in the 200 kW - 1000 kW size range and in the U.S. Fuel Cell Corporation of America was recently formed to take over the air-cooled phosphoric acid fuel cell technology developed by Westinghouse Corporation over the last decade. These efforts are expected to result in additional product availability in the U.S. in the short term. Cost are currently close to \$3,000/kW and with increased production volume are targeted to fall to \$1,500/kW. Federal funding approved in the September 26, 1994 Defense Appropriations Conference Report provided a total of \$18,000,000 for cost sharing "Innovative Environmental Security Technology Systems" including phosphoric acid fuel cells. The Federal cost share allows for up to \$1,000 per kW of capacity not to exceed one-third of the total cost. This would bring the immediate cost of phosphoric fuel cells down to the \$2,000 per kW for systems installed under this Federal program.

The molten carbonate fuel cell is about five years away from market introduction.^{1,5} It is expected to operate with a temperature of 1200F, with a 45-55 electrical efficiency, and a 75-80 overall efficiency. One version of the molten carbonate unit is currently being field tested by the Gas Research Institute. It is a 250 kW scaled down version of what will eventually be a 1-MW unit targeted for market introduction in the year 2000.

Research is also ongoing in the development of solid oxide fuel cells that are projected to have a working temperature of 1800F with 45-47% electric efficiency and 75-80% overall efficiency.¹ Solid oxide fuel cells hold the promise of directly reforming the natural gas in the power section rather than using two separate major components in the system design. However, the solid oxide fuel cells are not expected to be available any time soon.

The practical choice of a terrestrial fuel cell today is limited to the sole availability of the phosphoric acid fuel cell in the marketplace. The ONSI PC25 C phosphoric acid fuel cell is a self-contained 200 kW fully enclosed unit ready for installation on a poured concrete slab. It is available for a fixed price (\$600,000 without Federal cost sharing of \$200,000 currently available) and under warranty. The units have an integral power conditioner to ensure instantaneous load-following response with tight frequency control, even under transient operating conditions. They also provide 700,000 Btu/hr of hot water or low pressure steam. Current production capacity is estimated at 200 units per year.

The phosphoric acid fuel cell is a technology now entering the commercial marketplace after several years of development and extensive testing. Although its record of commercial success in the private sector is rather limited it has a somewhat impressive performance record to date. Over 70 ONSI 200 kW units have been installed in twelve countries in North America, Asia, and Europe. There has been over three quarters of a million operating hours and individual units have time exceeding 2.5 years (22,000 hours). Under commercial production support conditions, the units in the United States have demonstrated overall

availability exceeding 96% and have unscheduled outage intervals averaging over three months. The average unit uses over 60% of the available heat.

References for Appendix D:

1. P. Teagen, "Fuel Cells for Building Cogeneration Applications - Cost/Performance Requirements and Markets", Draft Report for the U.S. DOE/OBT/BED, Arthur D. Little, January 1995.
2. J. Kimball, "Fuel Cells - A Clean Efficient Source of Heat and Power", Gas Research Institute Technology Focus Sheet, June 1995.
3. J. Kimball, "Phosphoric Acid Fuel Cells for Onsite Power Generation", Gas Research Institute - Tech Profile, June 1995.
4. G. Sandelli, ONSI Corp. Technical Information Sheets and Reports describing the PC25 Model C Fuel Cell Power Plant.
5. E. Cicchetti, Editor, "End Use Highlights - Molten Carbonate Fuel Cell Begins Operation", Gas Research Institute Digest, Summer 1995, Volume 18, Number 2.