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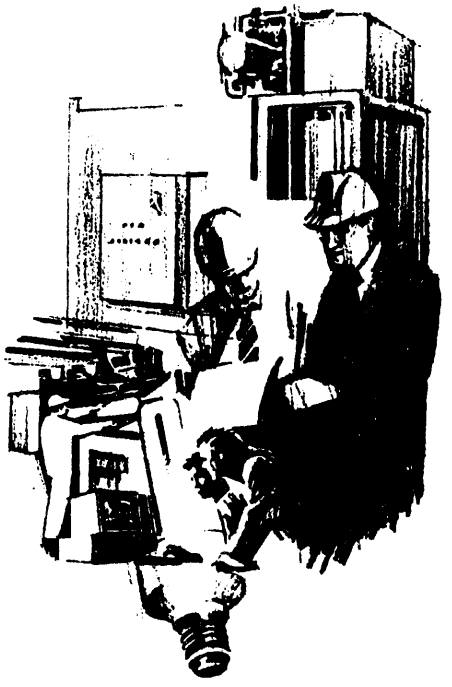
Analysis of Operating Alternatives for the Naval Computer and Telecommunications Station Cogeneration Facility at Naval Air Station North Island, San Diego, California



December 1993

Prepared for the U.S. Department of Energy
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Pacific Northwest Laboratory
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Analysis of Operating Alternatives for the Naval Computer and Telecommunications Station Cogeneration Facility at Naval Air Station North Island, San Diego, California

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Preface

The goal of the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP) is to facilitate energy efficiency improvements at federal facilities. This is accomplished by a balanced program of technology development, facility assessment, and use of cost-sharing procurement mechanisms. Technology development focuses upon the tools, software, and procedures used to identify and evaluate energy efficiency technologies and improvements. For facility assessment, FEMP provides metering equipment and trained analysts to federal agencies exhibiting a commitment to improve energy use efficiency. To assist in procurement of energy efficiency measures, FEMP helps federal agencies devise and implement performance contracting and utility demand-side management strategies.

Pacific Northwest Laboratory (PNL)[a] supports the FEMP mission of energy systems modernization. Under this charter, the Laboratory and its contractors work with federal facility energy managers to assess and implement energy efficiency improvements at federal facilities nationwide.

The Southwestern Division of the U.S. Navy (USN), Naval Facilities Engineering Command, in cooperation with FEMP, has tasked PNL to assess the economics and engineering feasibility of continuing to operate a cogeneration plan at the Naval Computer and Telecommunications Station (NCTS) at the Naval Air Station North Island (NASNI). The recommendations resulting from that assessment are presented in this report.

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Abstract

The Naval Facilities Engineering Command Southwestern Division commissioned Pacific Northwest Laboratory (PNL), in support of the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP), to determine the most cost-effective approach to the operation of the cogeneration facility in the Naval Computer and Telecommunications Station (NCTS) at the Naval Air Station North Island (NASNI). Nineteen alternative scenarios were analyzed by PNL on a life-cycle cost basis to determine whether to continue operating the cogeneration facility or convert the plant to emergency-generator status.

This report provides the results of the analysis performed by PNL for the 19 alternative scenarios. A narrative description of each scenario is provided, including information on the prime mover, electrical generating efficiency, thermal recovery efficiency, operational labor, and backup energy strategy. Descriptions of the energy and energy cost analysis, operations and maintenance (O&M) costs, emissions and related costs, and implementation costs are also provided for each alternative. A summary table presents the operational cost of each scenario and presents the result of the life-cycle cost analysis.

Executive Summary

The Naval Facilities Engineering Command Southwestern Division commissioned Pacific Northwest Laboratory (PNL), in support of the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP), to determine the most cost-effective approach to the operation of the cogeneration facility in the Naval Computer and Telecommunications Station (NCTS) at the Naval Air Station North Island (NASNI). This report describes 19 alternative scenarios for the cogeneration facility, provides an engineering and economic analysis, and presents a life-cycle cost analysis for each of the scenarios. Analysis results are presented for each major cost category (e.g., energy, operations and maintenance [O&M], emissions, and implementation).

Table S.1 provides the results of the life-cycle cost analysis in 1995 dollars for the 19 scenarios ranked from best (top) to worst (bottom). The life-cycle cost analysis is performed in 1995 dollars because it is assumed that implementation will actually occur during fiscal year (FY) 1995. Table S.2 provides a summary of the major cost components in 1993 dollars (the year of this report) for each of the alternative scenarios.

Scenarios 17 and 19 have the highest net savings, $15,082,000 and $14,911,000, respectively--compared to the existing system (Scenario 1). These scenarios involve repairing the existing reciprocating engines and converting them to act as emergency generators, providing emergency backup to the electric energy systems. San Diego Gas & Electric (SDG&E) provides the NCTS facility with primary electric service, and Applied Energy Incorporated (AEI) provides primary thermal energy. In Scenario 17, the emergency generators also supply backup thermal energy through waste-heat recovery from the generators. In Scenario 19, backup thermal energy is supplied by a new fast-response boiler. Because the NCTS facility requires a backup thermal source with a 15-minute response time to avoid a thermally activated shutdown of the computer systems, Scenario 19 is the preferred technical alternative.

Both scenarios assume that the U.S. Navy (USN) incorporates the SDG&E Interruptible Schedule I-3, Rate A. This rate schedule allows SDG&E to give the USN 10-minutes' notice, by telephone, to start the emergency generators remotely for the purpose of reducing SDG&E's system peak demand.

Table S.1. Summary of Life-Cycle Cost Analysis in 1995 Dollars

Scenario	Life-Cycle Cost ($)	Net Savings ($)
17	(2,560,000)	15,082,000
19	(2,389,000)	14,911,000
16	(1,430,000)	13,952,000
18	(1,259,000)	13,781,000
13	898,000	11,624,000
14	1,069,000	11,453,000
15	2,969,000	9,553,000
6	4,319,000	8,203,000
9	5,417,000	7,105,000
3	8,322,000	4,200,000
8	9,222,000	3,300,000
2	9,233,000	3,289,000
2	9,286,000	3,236,000
5	10,073,000	2,449,000
1	12,522,000	Base Case
7	13,897,000	(1,375,000)
4	14,988,000	(2,466,000)
11	16,099,000	(3,577,000)
10	28,923,000	(16,401,000)

Table S.2. Summary of Major Cost Components in 1993 Dollars

Scenario	Net Energy Savings ($/yr)	PWCSD[a] Labor Cost ($/yr)	Total Maintenance Cost ($/yr)	Emission Fees ($/yr)	Potential Emissions Credit ($)	Implementation Cost ($)
1	150,136	309,254	258,005	10,724	0	0
2	152,696	309,254	201,477	10,724	239,898	0
3	110,751	309,254	166,558	10,724	388,092	0
4	182,018	309,254	338,904	10,724	13,328	54,525
5	269,291	265,980	239,159	10,724	246,101	90,475
6	234,477	154,610	177,545	10,724	389,886	90,475
7	416,381	309,254	338,904	10,724	13,328	1,830,000
8	382,788	265,980	239,159	10,724	246,101	1,865,950
9	271,452	154,610	177,545	10,724	389,886	1,865,950
10	(37,689)	309,254	259,497	5,362	13,328	5,554,000
11	220,889	265,980	197,340	5,362	246,101	5,589,950
12	266,731	154,610	158,951	5,362	389,886	5,589,950
13	(2,418)	4,327	62,000	1,060	446,374	100,475
14	(2,418)	4,327	62,000	1,060	446,374	259,250
15	(2,418)	4,327	62,000	1,060	446,374	2,024,425
16	140,659	5,711	64,400	1,060	443,504	100,475
17	205,747	5,711	64,400	1,060	443,504	100,475
18	140,659	5,711	64,400	1,060	443,504	259,250
19	205,747	5,711	64,400	1,060	443,504	259,250

(a) Public Works Center San Diego

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Appreciation is extended to the following Pacific Northwest Laboratory staff whose efforts supported the study: Daryl Brown and Keith Daellenbach for cost estimates and life-cycle costing analysis, Steve Shankle and Donna Stucky for emissions and related analysis, Kate McMordie for field support and technical liaison, Sriram Somasundaram for technical peer review, and Cathy Anderson for final editing.

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Abbreviations and Acronyms

AEI	Applied Energy Incorporated
Btu	British thermal unit
CEC	California Energy Commission
CGA	cogeneration gas allowance
CO	carbon monoxide
DHW	domestic hot water
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
ETEC	Energy Technology Engineering Center
EUI	energy-use intensity
FEMP	Federal Energy Management Program
FERC	Federal Energy Regulatory Commission
FY	fiscal year
HHV	higher heating value
HVAC	heating, ventilating, and air conditioning
IHR	incremental heat rate
kW	kilowatt
kWh	kilowatt-hour
Mlb	thousand pounds
NASNI	Naval Air Station North Island
NCTS	Naval Computer and Telecommunications Station
NEESA	Navy Energy and Environmental Support Activity
NOx	oxides of nitrogen
O&M	operations and maintenance
Pentech	Pentech Services, Inc.
PM	particulate matter
PNL	Pacific Northwest Laboratory
ppmv	parts per million by volume
PWCSD	Public Works Center San Diego
QF	qualified facility
ROC	reactive organic compounds
SDAPCD	San Diego Air Pollution Control District
SDG&E	San Diego Gas & Electric
SOx	oxides of sulfur
TOC	total organic compounds
UPS	uninterruptible power supply
USN	U.S. Navy

1.0 Introduction

In 1986, a cogeneration plant was included in the original design and construction of the Naval Computer and Telecommunications Station (NCTS) facility, Building 1482, as part of Military Construction Project P-261 at the Naval Air Station North Island (NASNI) in San Diego, California (Gifford 1982). The plant is managed, owned, operated, and maintained by the U.S. Navy (USN) Public Works Center San Diego (PWCSD) under a Memorandum of Understanding with NCTS.

The plant consists of four 650-kW Caterpillar engines with waste-heat recovery from the engine exhaust, oil, and jacket-cooling system. The engines are operated as rich burn, using natural gas with a propane backup fuel supply. Hot water from the waste heat recovery system is used in Building 1482 for comfort heating, domestic hot water (DHW), air-conditioning reheat, and comfort cooling. Three 400-ton Carrier absorption chillers are used for cooling. The engines have been derated to 600 kW by the San Diego Air Pollution Control District (SDAPCD). Each engine is equipped with two catalytic converters, installed in series, to reduce engine emissions to acceptable levels.

The current state of the cogeneration equipment is important to this analysis. The engines are currently operated using manual settings. The automated load controls for the system have been unreliable since the plant's construction and have been bypassed. In addition, the air-fuel controllers are approaching the end of their life and will soon need to be replaced. Reliability of the cogeneration engines is a concern, and downtime appears to be excessive.

Two engines are capable of supplying all, or a majority of, the absorber load for one chiller. If additional heat is required, it is provided by the NASNI steam loop. Three engines are capable of supplying the entire load of a single chiller with excess heat rejected to the cooling towers.

Since the plant was brought on line, a new long-term steam contract has been signed with Applied Energy Incorporated (AEI), which operates several cogeneration sites for the USN at San Diego and provides steam to the NASNI steam loop. The steam contract provides for a minimum steam purchase of 73,000 Mlb of steam per month by the USN. This is well above the maximum demand encountered in the 3 years the contract has been in place. Credit is applied to the steam bill for condensate returned and for electricity generated by AEI with excess steam. In addition, the USN has upgraded its electric distribution system to receive power from San Diego Gas & Electric (SDG&E) at 69 kV, allowing the USN to purchase power under a reduced-transmission rate schedule.

Currently, Building 1482 is not fully loaded because of the continuing miniaturization of computers. As a result, full load is not being placed on the electrical and thermal systems at the site. On the other hand, the ongoing consolidation of USN commands is causing a transition of additional functions to NCTS. As a result, additional demands will be placed on the building's electrical and thermal systems.

Continuous cooling and electric power must be provided to the NCTS facility. Currently, backup thermal energy is provided by the NASNI steam distribution loop, and backup electric power is provided by the NASNI electric distribution grid. Three 750-kW uninterruptible power supplies (UPS) are capable of providing power for 15 minutes to support the NCTS during an emergency power interruption.

A study of the cost-effectiveness of continued plant operation was performed by the Navy Energy and Environmental Support Activity (NEESA) in 1991 (Zavala and Heller 1991). That study concluded that it is feasible for the plant to operate only in a peak-shaving mode but did not make recommendations for additional backup thermal and electric power.

The USN commissioned Pacific Northwest Laboratory (PNL), in support of the U.S. Department of Energy (DOE) Federal Energy Management Program (FEMP), to determine the most cost-effective approach to the operation of the cogeneration station with continuous requirements for backup electric and thermal sources. The goal is to minimize the life-cycle costs to the USN, either by optimizing the operation of the cogeneration facility or by shutting it down. This study evaluates 19 alternative operating scenarios for the cogeneration facility, ranging from continued operation to plant shutdown. The objective of this project is to minimize life-cycle costs to the USN, including raw-energy (natural gas, electricity, and steam), labor, maintenance, and contract costs. Included in the total cost to the USN is the cost of providing reliable emergency backup of electric and thermal energy to the facility.

Nineteen alternative scenarios were analyzed by PNL to determine whether to continue operating the cogeneration facility or convert the plant to emergency-generator status. This analysis considered the existing and alternative prime movers, alternative operating schedules, and four operating load strategies. The analysis utilized the available information to determine utility consumption and cost, labor cost, and maintenance cost.

This report contains four major sections and several appendices. In Section 2.0, the alternative scenarios are presented. Section 3.0 presents the utility rate schedules and their associated energy cost information as they pertain to this analysis. The analysis of the alternative scenarios and supporting information are described in Section 4.0. The appendices contain information and calculations used to analyze the alternative scenarios. Appendix A contains 1992 PWCSD meter utility reports. Natural-gas unit cost calculations for 1992 are shown in Appendix B. Appendix C contains PWCSD Federal Energy Regulatory Commission (FERC) calculations for 1992. Marginal energy cost calculations for cogen gas rates are presented in Appendix D, and non-cogen gas rates are presented in Appendix E. Appendix F contains thermal energy analyses for Scenarios 1 through 12. Appendix G contains energy analyses for Scenarios 1 through 12. Appendix H contains a Permit to Operate, and Appendix I contains an energy technology engineering center report for the NCTS at NASNI.

2.0 Alternative Scenarios

Nineteen alternative scenarios have been analyzed to determine whether to continue operating the NCTS cogeneration plant or to convert the plant to emergency-generator status. These scenarios, introduced below and summarized in Table 2.1, are discussed in subsections that follow.

- **Scenario 1: Operate plant continuously.** The NCTS cogeneration facility continues its current operation, operating continuously. SDG&E electric service is used for emergency power, and AEI steam service provides emergency backup thermal energy to the facility. This scenario represents the existing system or base case.

- **Scenario 2: Operate on-peak and semi-peak periods.** The NCTS cogeneration plant continues its current operation, but only during the SDG&E on-peak and semi-peak periods. The cogeneration facility functions as an emergency generator during the off-peak period, providing both electric and thermal energy backup.

- **Scenario 3: Operate on-peak period.** The NCTS cogeneration plant continues its current operation, but only during the SDG&E on-peak period. The cogeneration facility functions as an emergency generator during the semi-peak and off-peak periods, providing both electric and thermal energy backup.

- **Scenario 4: Repair engines and operate continuously.** The NCTS cogeneration facility is upgraded to operate as it was originally intended and operates continuously. Operating procedures are modified to utilize more of the recoverable thermal energy. SDG&E electric service is used for emergency power, and AEI steam service provides emergency backup thermal energy to the facility.

- **Scenario 5: Repair engines and operate on-peak and semi-peak periods.** The NCTS cogeneration facility is upgraded to operate as it was originally intended and operates during the SDG&E on-peak and semi-peak periods. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility functions as an emergency generator during the off-peak period, providing both electric and thermal energy backup.

- **Scenario 6: Repair engines and operate on-peak period.** The NCTS cogeneration facility is upgraded to operate as it was originally intended and operates during the SDG&E on-peak period. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility functions as an emergency generator during the semi-peak and off-peak periods, providing both electric and thermal energy backup.

- **Scenario 7: Replace engines and operate continuously.** The cogeneration engines and controls are replaced with new reciprocating engines with a higher electrical efficiency. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates continuously. SDG&E electric service is used for emergency power, and AEI steam service provides emergency backup thermal energy to the facility.

Table 2.1. Summary of Alternative Scenarios

Scenario	Description	Load (kW)	Number of Engines: Available	Number of Engines: Operating	Operating Period: On-Peak	Operating Period: Semi-Peak	Operating Period: Off-Peak
1	As-Is	600	4	2	X	X	X
2	As-Is	600	4	2	X	X	
3	As-Is	600	4	2	X		
4	Repaired	600	4	4	X	X	X
5	Repaired	600	4	4	X	X	
6	Repaired	600	4	4	X		
7	New Recips	610	4	4	X	X	X
8	New Recips	610	4	4	X	X	
9	New Recips	610	4	4	X		
10	Gas Turbines	1540	2	2	X	X	X
11	Gas Turbines	1540	2	2	X	X	
12	Gas Turbines	1540	2	2	X		
13	Emerg. Cogen	600	4	4			
14	Emerg. Gen.	600	4	4			
15	New Gen.	610	4	4			
16	SDG&E Inter.	600	4	4	Same as 13 w/I-3 Rate D		
17	SDG&E Inter.	600	4	4	Same as 13 w/I-3 Rate A		
18	SDG&E Inter.	600	4	4	Same as 14 w/I-3 Rate D		
19	SDG&E Inter.	600	4	4	Same as 14 w/I-3 Rate A		

- **Scenario 8: Replace engines and operate on-peak and semi-peak periods.** The cogeneration engines and controls are replaced with new reciprocating engines with a higher electrical efficiency. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates during the SDG&E on-peak and semi-peak periods. The cogeneration facility functions as an emergency generator during the off-peak period, providing both electric and thermal energy backup.

- **Scenario 9: Replace engines and operate on-peak period.** The cogeneration engines and controls are replaced with new reciprocating engines with a higher electrical efficiency. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates during the SDG&E on-peak period. The cogeneration facility functions as an emergency generator during the semi-peak and off-peak periods, providing both electric and thermal energy backup.

- **Scenario 10: Install gas turbines and operate continuously.** The cogeneration engines and controls are replaced with new gas turbines. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates continuously. SDG&E

electric service is used for emergency power, and AEI steam service provides emergency backup thermal energy to the facility.

- **Scenario 11: Install gas turbines and operate on-peak and semi-peak periods.** The cogeneration engines and controls are replaced with new gas turbines. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates during the SDG&E on-peak and semi-peak periods. The cogeneration facility functions as an emergency generator during the off-peak period, providing both electric and thermal energy backup.

- **Scenario 12: Install gas turbines and operate on-peak period.** The cogeneration engines and controls are replaced with new gas turbines with a higher electrical efficiency. Operating procedures are modified to utilize more of the recoverable thermal energy. The cogeneration facility operates during the SDG&E on-peak period. The cogeneration facility functions as an emergency generator during the semi-peak and off-peak periods, providing both electric and thermal energy backup.

- **Scenario 13: Convert plant to emergency-generator status for electrical and thermal energy.** The NCTS cogeneration facility is converted to an emergency-generator facility, providing both emergency electric power and emergency thermal energy. SDG&E provides the facility with primary electric energy, and AEI provides primary thermal energy.

- **Scenario 14: Convert plant to emergency-generator status and install backup boiler.** The NCTS cogeneration facility is converted to an emergency-generator facility, providing emergency electric power. A boiler is installed to provide emergency thermal energy. SDG&E provides the facility with primary electric energy, and AEI provides primary thermal energy.

- **Scenario 15: Replace plant with emergency generators and backup boiler.** The NCTS cogeneration facility is converted to an emergency-generator facility. New emergency generators are installed to provide emergency electric power. A boiler is installed to provide emergency thermal energy. SDG&E provides the facility with primary electric energy, and AEI provides primary thermal energy.

- **Scenario 16: Utilize SDG&E Interruptible Schedule I-3, Rate D with Scenario 13.** This scenario is the same as Scenario 13. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate D, using the NCTS emergency-generator facility to shed demand at the request of SDG&E during its system peaks.

- **Scenario 17: Utilize SDG&E Interruptible Schedule I-3, Rate A with Scenario 13.** This scenario is the same as Scenario 13. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate A, using the NCTS emergency-generator facility to shed demand at the request of SDG&E during its system peaks.

- **Scenario 18: Utilize SDG&E Interruptible Schedule I-3, Rate D with Scenario 14.** This scenario is the same as Scenario 14. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate D, using the NCTS emergency-generator facility to shed demand at the request of SDG&E during its system peaks.

- **Scenario 19: Utilize SDG&E Interruptible Schedule I-3, Rate A with Scenario 14.** This scenario is the same as Scenario 14. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate A, using the NCTS emergency-generator facility to shed demand at the request of SDG&E during its system peaks.

2.1 Scenario 1: Operate Plant Continuously

Under this scenario, the NCTS cogeneration facility continues its current operation, operating continuously. The cogeneration facility consists of four Caterpillar model G399 internal-combustion reciprocating engines rated at 650-kW maximum output. The facility currently operates two engines manually, attempting to maintain engine loading at approximately 600-kW output. Review of the operating records indicates that the engines operate at an average load of 570 kW, assuming that two of the four engines are operating continuously (see Appendix A). Assuming that two engines are continuously on-line corresponds to a 94% load utilization factor (94% of 600 kW). The engine generators specified have a full-load (650 kW) heat rate of 12,011 Btu/kWh based on the higher heating value (HHV) of the fuel. This corresponds to an electrical efficiency of 28.4% at full load.

The facility is continuously staffed. Staffing consists of one maintenance mechanic (WG-10) on the day shift, five watch standers (WG-11) on rotating shifts, and one foreman on the day shift. Preventive maintenance is provided by the subcontractor, Pentech Services, Inc. (Pentech).

Waste heat recovered from the engines is used to meet thermal energy requirements of the NCTS facility, consisting of DHW, building heat, air-conditioning reheat, and building cooling requirements through absorption chillers. The NCTS facility has three 400-ton absorption chillers. Only one chiller is required to meet the facility's peak load. To distribute operating hours, the operating chiller is rotated among the three available chillers. Two engines are capable of providing more than enough thermal energy to meet the facility requirements. Thermal energy recovered from the cogeneration system, but not utilized, is rejected through cooling towers.

Emergency power is provided through interconnection to the SDG&E electric grid. An UPS provides 15 minutes of backup power during an interruption. Steam is available from AEI to provide backup of thermal energy requirements for the NCTS facility. A steam heat exchanger is used to provide hot water to the various thermal systems. Only one of the three chillers is capable of being operated with the steam-supplied heat. This chiller has always consumed some steam energy when in operation. Analysis of the steam and thermal energy logs indicates that the NCTS facility meets approximately 30% of the thermal energy requirements with steam energy, even though thermal energy recovered from the cogeneration system is available.

Fuel consumption, electricity generation, and thermal energy utilization, obtained from PWCSD meters, are provided in Appendix A. The utility rate schedules and assumptions made in estimating operating costs are discussed in Section 3.0.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (i.e., 4,380 h/engine·yr) beginning in 1995, the existing engines will need to be

replaced in 2015. At the end of the life-cycle cost analysis period, it is estimated that the replacement engines will have approximately 81% of their life remaining. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

2.2 Scenario 2: Operate On-Peak and Semi-Peak Periods

Under this scenario, the cogeneration facility continues to operate two engines, as in Scenario 1, during the SDG&E on-peak and semi-peak periods. The cogeneration facility does not operate during the off-peak period. During the off-peak period, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam.

In case of interruption in either the electric power or steam supply during the off-peak period, the cogeneration system is manually restarted. Because it is believed that the existing controls are not capable of starting the plant automatically, continuous staffing of the facility is required, as in Scenario 1, even during shutdown. Staffing consists of one maintenance mechanic (WG-10) on the day shift, five watch standers (WG-11) on rotating shifts, and one foreman on the day shift. Preventive maintenance is provided by the subcontractor, Pentech.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (2,040 h/engine·yr) beginning in 1995, the existing engines will not need to be replaced within the life-cycle cost analysis period. The economic value of the engines at the end of the life-cycle cost analysis period is assumed to be negligible because of the age of the engines.

2.3 Scenario 3: Operate On-Peak Period

Under this scenario, the cogeneration facility continues to operate two engines, as in Scenario 1, during the SDG&E on-peak period. The cogeneration facility does not operate during the semi-peak and off-peak periods. During the semi-peak and off-peak periods, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam.

In case of interruption in either the electric power or steam supply during the semi-peak and off-peak periods, the cogeneration system is manually restarted. Because it is believed that the existing controls are not capable of starting the plant automatically, continuous staffing of the facility is required, as in Scenario 1, even during shutdown. Staffing consists of one maintenance mechanic (WG-10) on the day shift, five watch standers (WG-11) on rotating shifts, and one foreman on the day shift. Preventive maintenance is provided by the subcontractor, Pentech.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (594.5 h/engine·yr) beginning in 1995, the existing engines will not need to be replaced within the life-cycle cost analysis period. The economic value of the engines at the end of the life-cycle cost analysis period is assumed to be negligible because of the age of the equipment.

2.4 Scenario 4: Repair Engines and Operate Continuously

Under this scenario, the existing cogeneration facility is upgraded to operate as it was originally intended and operates continuously. This upgrade includes new load-sharing and speed controls, new air fuel ratio controllers, and additional repairs as outlined in Appendix I.

The cogeneration facility continuously operates all four engines at the full derated load of 600 kW. Scheduled downtime is assumed to be approximately 3%. All thermal energy required by the NCTS facility is recovered from the cogeneration system. No steam from the AEI steam system is consumed to meet the normal thermal energy load, except in emergency operating conditions. Excess thermal energy recovered from the cogeneration system is rejected though the existing cooling towers.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (8,500 h/engine·yr) beginning in 1995, the existing engines will need to be replaced in 2005, and again in 2019. At the end of the life-cycle cost analysis period, it is estimated that the replacement engines will have approximately 89% of their life remaining. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

The facility is continuously staffed as in Scenario 1, consisting of one maintenance mechanic (WG-10) on the day shift, five watch standers (WG-11) on rotating shifts, and one foreman on the day shift. Preventive maintenance is still provided by the subcontractor, Pentech.

Emergency electric power is provided by the SDG&E electrical grid. Emergency thermal energy is provided by the AEI steam system.

2.5 Scenario 5: Repair Engines and Operate On-Peak and Semi-Peak Periods

Under this scenario, the existing cogeneration facility is upgraded to operate as it was originally intended as in Scenario 4. This upgrade includes new load-sharing and speed controls, new air-to-fuel ratio controllers, and additional repairs as outlined in Appendix I. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The cogeneration facility operates all four engines at the full derated load of 600 kW during the SDG&E on-peak and semi-peak periods. Scheduled downtime is assumed to be approximately 3%. During the off-peak period, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (3,959 h/engine·yr) beginning in 1995, the existing engines will need to be replaced in 2017. At the end of the life-cycle cost analysis period, it is estimated that the replacement

engines will have approximately 87% of their life remaining. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

All thermal energy required by the NCTS facility is recovered from the cogeneration system when it is in operation. No steam from the AEI steam system is consumed to meet the thermal energy load while the cogeneration system is operating. Excess thermal energy recovered from the cogeneration system is rejected through the existing cooling towers.

The cogeneration plant is staffed during the on-peak and semi-peak periods. It is not staffed during the off-peak period unless a power interruption occurs. Because the SDG&E operating periods do not correspond exactly to PWCSD work shifts, it is assumed that PWCSD staff can be rotated to other PWCSD job assignments when the cogeneration system is not in operation. This assumption is further detailed in Section 4.3.2. Staffing consists of approximately one foreman on the day shift, one maintenance mechanic (WG-10) on the day shift, and one watch stander (WG-11) present one-half hour before scheduled operation until one-half hour after scheduled shutdown. Preventive maintenance is still provided by the subcontractor, Pentech.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central heating, ventilating, and air-conditioning (HVAC) system.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electric grid and emergency thermal energy is provided by the AEI steam system. During the off-peak period when the cogeneration system is not running, the system acts as an emergency-generator facility. The cogeneration system is started automatically if an interruption occurs in the electric power or steam supply.

2.6 Scenario 6: Repair Engines and Operate On-Peak Period

Under this scenario, the existing cogeneration facility is upgraded to operate as it was originally intended as in Scenario 4. This upgrade includes new load-sharing and speed controls, new air fuel ratio controllers, and additional repairs as outlined in Appendix I. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The cogeneration facility operates all four engines at the full derated load of 600 kW during the SDG&E on-peak period. Scheduled downtime is assumed to be approximately 3%. During the semi-peak and off-peak periods, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam.

The existing engines have a total estimated life of 120,000 run-hours or 25 years (maximum). As of October 1992, the engines have operated an average of 20,700 h each. At the proposed operating schedule (1,154 h/engine·yr) beginning in 1995, the existing engines will not need to be replaced within the life-cycle cost analysis period. The economic value of the engines at the end of the life-cycle cost analysis period is assumed to be negligible because of the age of the engines.

All thermal energy required by the NCTS facility is recovered from the cogeneration system when it is in operation. No steam from the AEI steam system is consumed to meet the thermal energy load while the cogeneration system is operating. Excess thermal energy recovered from the cogeneration system is rejected through the existing cooling towers.

The cogeneration plant is staffed during the on-peak period. It is not staffed during the semi-peak and off-peak periods unless a power interruption occurs. Because the SDG&E operating periods do not correspond exactly to PWCSD work shifts, it is assumed that PWCSD staff can be rotated to other PWCSD job assignments when the cogeneration system is not in operation. This assumption is further detailed in Section 4.3.2. Staffing consists of approximately one foreman, one maintenance mechanic (WG-10), and one watch stander (WG-11) present one-half hour before scheduled operation until one-half hour after scheduled operation. Preventive maintenance is still provided by the subcontractor, Pentech.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Control system that currently monitors and controls much of the central HVAC system.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electric grid and emergency thermal energy is provided by the AEI steam system. During the semi-peak and off-peak periods when the cogeneration system is not running, the system acts as an emergency-generator facility. The cogeneration system is started automatically if an interruption occurs in the electric power or steam supply.

2.7 Scenario 7: Replace Engines and Operate Continuously

Under this scenario, the engine generators are replaced with four new engine generators with approximately the same output as the existing system. It is estimated that the existing engines have a salvage value of $50,000 each (see Appendix I); however, it is assumed that the salvage value will cover the cost of their removal, sale, and transfer. Because the value of the generated electric energy is the driving economic factor (see Section 4.1.5), the new generators specified for this analysis have a heat rate of 10,500 Btu/kWh based on the HHV of the fuel. This corresponds to an electrical efficiency of 32.5% at full load, which is a higher electrical efficiency than the existing engines. The engines selected for this analysis are rated at 610 kW (Hay 1988). The new engines are equipped with completely new control systems. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The existing heat recovery system can be adapted to the new engines. With a higher electrical efficiency, less energy is recoverable as useful thermal energy. It is estimated that 38% of the input energy can be recovered as useful thermal energy, still providing more than enough energy to meet the thermal energy requirements of the facility.

The cogeneration facility continuously operates all four engines at the full-load rating of 610 kW. Scheduled downtime is assumed to be approximately 3%. The cogeneration facility is staffed as outlined in Scenario 1. All thermal energy required by the NCTS facility is recovered from the cogeneration system.

The new engines have a total estimated life of 120,000 run-hours or 25 years (maximum). At the proposed operating schedule (8,500 h/engine·yr) beginning in 1995, the new engines will need to be replaced in 2009. At the end of the life-cycle cost analysis period, it is estimated that the replacement engines will have approximately 18% of their life remaining. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

Emergency electric power is provided by the SDG&E electric grid. Emergency thermal energy is provided by the AEI steam system.

2.8 Scenario 8: Replace Engines and Operate On-Peak and Semi-Peak Periods

Under this scenario, the engine generators are replaced with four new engine generators with approximately the same output as the existing system as in Scenario 7. Similarly, it is estimated that the existing engines have a salvage value of $50,000 each (see Appendix I); however, it is assumed that the salvage value will cover the cost of their removal, sale, and transfer. Because the value of the generated electric energy is the driving economic factor (see Section 4.1.5), the new generators specified have a heat rate of 10,500 Btu/kWh based on the HHV of the fuel. This corresponds to an electrical efficiency of 32.5% at full load, which is a higher electrical efficiency than the existing engines. The engines selected for this analysis are rated at 610 kW (Hay 1988). The new cogeneration system is equipped with a completely new control system. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The existing heat recovery system can be adapted to the new engines. However, with a higher electrical efficiency, less waste heat is available for recovery as useful thermal energy. It is estimated that 38% of the input energy can be recovered as useful thermal energy, still providing more than enough heat to meet the thermal energy requirements. All thermal energy required by the NCTS facility is recovered from the cogeneration system when it is operating.

The cogeneration facility operates all four engines at the full-load rating of 610 kW during the SDG&E on-peak and semi-peak periods. Scheduled downtime is assumed to be approximately 3%. During the off-peak period, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam. The cogeneration facility is staffed as outlined in Scenario 5.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

The new engines have a total estimated life of 120,000 run-hours or 25 years (maximum). At the proposed operating schedule (3,959 h/engine·yr) beginning in 1995, the new engines will not need to be replaced in the life-cycle cost analysis period. The economic value of the engines at the end of the life-cycle cost analysis period is assumed to be negligible because of the age of the equipment. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electrical grid and emergency thermal energy is provided by the AEI steam system. During the off-peak period when the cogeneration system is not running, the system acts as an emergency-generator facility. In case of interruption in either the electric power or steam supply, the cogeneration system is started automatically.

2.9 Scenario 9: Replace Engines and Operate On-Peak Period

Under this scenario, the engine generators are replaced with four new engine generators with approximately the same output as the existing system as in Scenario 7. Similarly, it is estimated that the existing engines have a salvage value of $50,000 each (see Appendix I); however, it is assumed that the salvage value will cover the cost of their removal, sale, and transfer. Because the value of the generated electric energy is the driving economic factor (see Section 4.1.5), the new generators specified have a heat rate of 10,500 Btu/kWh based on the HHV of the fuel. This corresponds to an electrical efficiency of 32.5% at full load, which is a higher electrical efficiency than the existing engines. The engines selected for this analysis are rated at 610 kW. The new cogeneration system is equipped with a new control system. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The existing heat recovery system can be adapted to the new engines. With a higher electrical efficiency, less energy is recoverable as useful thermal energy. It is estimated that 38% of the input energy can be recovered as useful thermal energy, still providing more than enough energy to meet the thermal energy requirements. All thermal energy required by the NCTS facility is recovered from the cogeneration system when it is operating.

The cogeneration facility operates all four engines at the full-load rating of 610 kW during the SDG&E on-peak period. Scheduled downtime is assumed to be approximately 3%. During the semi-peak and off-peak periods, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam. The cogeneration facility is staffed as outlined in Scenario 6.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

The new engines have a total estimated life of 120,000 run-hours or 25 years (maximum). At the proposed operating schedule (1,154 h/engine·yr) beginning in 1995, the new engines will not need to be replaced in the life-cycle cost analysis period. The economic value of the engines at the end of the life-cycle cost analysis period is assumed to be negligible because of the age of the equipment. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electrical grid and emergency thermal energy is provided by the AEI steam system. During the semi-peak and off-peak periods when the cogeneration system is not running, the system acts as an emergency-generator facility. In case of interruption in either the electric power or steam supply, the cogeneration system is started automatically.

2.10 Scenario 10: Install Gas Turbines and Operate Continuously

Under this scenario, the existing engine generators are replaced with two new gas turbine generators with a total electric capacity similar to that of the existing system. The new generators specified have a heat rate of 14,620 Btu/kWh based on the HHV of the fuel. This corresponds to an electrical efficiency of 22.5% at full load. The turbines selected for this analysis are rated at 1,540 kW each (Hay 1988). The new turbines are equipped with a complete new control system. The new controls are capable of reliably starting the turbines automatically, controlling the air-to-fuel ratio, and controlling the turbine loading.

The gas turbines require a new heat recovery system. It is estimated that 45% of the input energy can be recovered as useful thermal energy, still providing more than enough energy to meet the thermal energy requirements of the facility.

The cogeneration facility continuously operates both turbines at the full-load rating of 1,540 kW. Scheduled downtime is assumed to be approximately 3%. The cogeneration facility is staffed as outlined in Scenario 1. Special training is provided to the staff on gas turbines. All thermal energy required by the NCTS facility is recovered from the cogeneration system.

The new gas turbines have a total estimated life of 180,000 run-hours or 30 years (maximum). At the proposed operating schedule (8,500 h/engine·yr) beginning in 1995, the new turbines will need to be replaced in 2016. At the end of the life-cycle cost analysis period, it is estimated that the replacement turbines will have approximately 78% of their life remaining. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis.

The salvage value of the existing reciprocating engines is estimated to be $50,000 each (in 1993); however, it is assumed that this will cover the cost of their removal, sale, and transfer.

Emergency electric power is provided by the SDG&E electric grid. Emergency thermal energy is provided by the AEI steam system.

2.11 Scenario 11: Install Gas Turbines and Operate On-Peak and Semi-Peak Periods

Under this scenario, the existing engine generators are replaced with two new gas turbine generators with a total electric capacity similar to that of the existing system as in Scenario 10. The new generators specified have a heat rate of 14,620 Btu/kWh based on the HHV of the fuel, corresponding to an electrical efficiency of 22.5% at full load. The turbines selected for this analysis are rated at 1,540 kW each. The new turbines are equipped with a complete new control system. The new controls are capable of reliably starting the turbines automatically, controlling the air-to-fuel ratio, and controlling the turbine loading.

The gas turbines require a new heat recovery system. It is estimated that 45% of the input energy can be recovered as useful thermal energy, still providing more than enough energy to meet the thermal energy requirements.

The cogeneration facility operates both turbines at the full-load rating of 1,540 kW during the SDG&E on-peak and semi-peak periods. Scheduled downtime is assumed to be approximately 3%. During the off-peak period, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam. The cogeneration facility is staffed as outlined in Scenario 5. Special training is provided to the staff on gas turbines.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

The new gas turbines have a total estimated life of 180,000 run-hours or 30 years (maximum). At the proposed operating schedule (3,959 h/engine·yr) beginning in 1995, the new turbines will not need to be replaced in the life-cycle cost analysis period. At the end of the analysis period, it is estimated that the turbines will have approximately 17% of their economic life remaining because of the age of the turbines. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis. The salvage value of the existing engines is estimated to be $50,000 each (in 1993); however, it is assumed that this will cover the cost of their removal, sale, and transfer.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electric grid and emergency thermal energy is provided by the AEI steam system. During the off-

peak period when the cogeneration system is not running, the system acts as an emergency-generator facility. The cogeneration facility is started automatically if an interruption occurs in the electric power or steam supply.

2.12 Scenario 12: Install Gas Turbines and Operate On-Peak Period

Under this scenario, the existing engine generators are replaced with two new gas turbine generators with a total electric capacity similar to that of the existing system. The new generators specified have a heat rate of 14,620 Btu/kWh based on the HHV of the fuel, corresponding to an electrical efficiency of 22.5% at full load. The turbines selected for this analysis are rated at 1,540 kW each as in Scenario 10. The new turbines are equipped with new control systems. The new controls are capable of reliably starting the engines automatically, controlling the air-to-fuel ratio, and controlling the engine loading.

The gas turbines require a new heat recovery system. It is estimated that 45% of the input energy can be recovered as useful thermal energy, still providing more than enough energy to meet the thermal energy requirements.

The cogeneration facility operates both turbines at the full-load rating of 1,540 kW during the SDG&E on-peak period. Scheduled downtime is assumed to be approximately 3%. During the semi-peak and off-peak periods, electric power is supplied by SDG&E and thermal energy requirements are supplied by AEI steam. The cogeneration facility is staffed as outlined in Scenario 6. Special training is provided to the staff on gas turbines.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

The new gas turbines have a total estimated life of 180,000 run-hours or 30 years (maximum). At the proposed operating schedule (1,154 h/engine·yr) beginning in 1995, the new turbines will not need to be replaced in the life-cycle cost analysis period. At the end of the analysis period, it is estimated that the turbines will have approximately 17% of their economic life remaining because of the age of the turbines. The heat recovery system, however, has a longer estimated life and will not need to be replaced within the life of this analysis. The salvage value of the existing engines is estimated to be $50,000 each (in 1993); however, it is assumed that this will cover the cost of their removal, sale, and transfer.

While the cogeneration system is running, emergency electric power is provided by the SDG&E electrical grid and emergency thermal energy is provided by the AEI steam system. During the semi-peak and off-peak periods when the cogeneration system is not running, the system acts as an emergency-generator facility. The cogeneration system is started automatically if an interruption occurs in the electric power or steam supply.

2.13 Scenario 13: Convert Plant to Emergency-Generator Status for Electrical and Thermal Energy

Under this scenario, the existing cogeneration facility is converted to an emergency-generator facility. SDG&E provides the NCTS facility with primary electric energy. AEI provides primary thermal energy. The cogeneration system is automatically started if an interruption occurs in the electric power or steam supply.

The existing engines are repaired to reliable operating status as automatic-start emergency generators, which includes new load-sharing and speed controls, new air-fuel ratio controllers, and additional repairs as outlined in Appendix I.

It is assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter.[a] It is also assumed that the emergency generator facility is staffed by one watch stander (WG-11) when the generators are operating.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

2.14 Scenario 14: Convert Plant to Emergency-Generator Status and Install Backup Boiler

Under this scenario, the cogeneration facility is converted to an emergency-generator facility. The NCTS facility is provided with primary electric energy by SDG&E and AEI provides primary thermal energy. The cogeneration system is automatically started if an interruption occurs in the electric power supply. In case of interruption in the steam supply, a new fast-start natural-gas-fired hot-water boiler is automatically started.

The existing engines are repaired to reliable operating status as automatic-start emergency generators as discussed in Scenario 13. In addition, the existing heat recovery system is disconnected and abandoned-in-place. The cooling tower is still used to provide engine cooling.

A new natural-gas-fired water boiler is also installed and interconnected to the thermal energy system using heat exchangers in a closed-loop system. The boiler is in cold standby during standard operating conditions.

(a) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

It is assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter. It is also assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

2.15 Scenario 15: Replace Plant with Emergency Generators and Backup Boiler

Under this scenario, the cogeneration facility is replaced with a new emergency-generator facility. The NCTS facility is provided with primary electric energy by SDG&E and AEI provides primary thermal energy. The new generators are automatically started if an interruption occurs in the electric power supply. If an interruption occurs in the steam supply, a new fast-start natural-gas-fired water boiler is automatically started.

The existing engines are replaced with four new automatic-starting emergency generators rated at 600 kW, which includes a complete new control system. The existing heat recovery system is also disconnected and abandoned-in-place.

In addition, a new natural-gas-fired water boiler is installed and interconnected to the thermal energy system using heat exchangers in a closed-loop system. The boiler is in cold standby during standard operating conditions.

It is assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter.[a] It is also assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

(a) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

2.16 Scenario 16: Utilize SDG&E Interruptible Schedule I-3, Rate D, with Scenario 13

Under this scenario, the cogeneration facility is modified as in Scenario 13. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate D. This schedule is more fully discussed in Section 3.1. This rate schedule option provides a monthly credit to the electric utility bill. In return for this credit, PWCSD agrees to operate the emergency generators, at SDG&E's request, to reduce the NASNI electrical demand. This rate schedule, and its subject facilities, is used by SDG&E as another generating source when needed.

Schedule I-3, Rate D, allows SDG&E to give PWCSD 30-minutes' notice, by telephone, to start the emergency generators, get them up to capacity, and on-line. SDG&E also notifies PWCSD when the generators are no longer required. These interruptions typically occur less than 30 times per year for total engine operating hours of less than 80 h/yr. These are typical maximums according to SDG&E; however, the contract allows SDG&E to require additional interruptions for longer operating periods. This analysis assumes an average interruption of 56 h/yr.[a] Incorporating this rate option requires a contractual agreement. The contract can be for a 1-year or 5-year term. Because the incentive is greater for the longer contractual agreement, this scenario assumes PWCSD will enter into 5-year contracts.

It is assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating. It is also assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter,[b] in addition to operation at the request of SDG&E under the new rate option.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

2.17 Scenario 17: Utilize SDG&E Interruptible Schedule I-3, Rate A, with Scenario 13

Under this scenario, the cogeneration facility is modified as in Scenario 13. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate A. This schedule is more fully discussed in Section 3.1. This rate schedule option provides a monthly credit to the electric utility bill. In return for this credit, PWCSD agrees to allow SDG&E to operate the emergency generators,

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(a) Facsimile Communication, Sharon Gorden, SDG&E. April 30, 1993, 9:00 a.m. PDT.
(b) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

at SDG&E's request, to reduce the NASNI electrical demand on the SDG&E system. This rate schedule, and its subject facilities, is used by SDG&E as another generating source when needed.

Schedule I-3, Rate A, allows SDG&E to give PWCSD 10-minutes' notice, by telephone, and start the emergency generators remotely. These interruptions typically occur less than 30 times per year for total engine operating hours of less than 80 h/yr. These are typical maximums according to SDG&E; however, the contract allows SDG&E to require additional interruptions for longer operating periods. This analysis assumes an average interruption of 56 h/yr.[a] Incorporating this rate option requires a contractual agreement. The contract can be for a 1-year or 5-year term. Because the incentive is greater for the longer contractual agreement, this scenario assumes PWCSD will enter into 5-year contracts.

It is assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating. It is also assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter,[b] in addition to operation at the control of SDG&E under the new rate option.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

2.18 Scenario 18: Utilize SDG&E Interruptible Schedule I-3, Rate D, with Scenario 14

Under this scenario, the cogeneration facility is modified as in Scenario 14, including the installation of the backup boiler. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate D. This schedule is more fully discussed in Section 3.1. This rate schedule option provides a monthly credit to the electric utility bill. In return for this credit, PWCSD agrees to operate the emergency generators, at SDG&E's request, to reduce the NASNI electrical demand. This rate schedule, and its subject facilities, is used by SDG&E as another generating source when needed.

Schedule I-3, Rate D, allows SDG&E to give PWCSD 30-minutes' notice, by telephone, to start the emergency generators, get them up to capacity, and on-line. SDG&E also notifies PWCSD when the generators are no longer required. These interruptions typically occur less than 30 times per year for total engine operating hours of less than 80 h/yr. These are typical maximums according to SDG&E; however, the contract allows SDG&E to require additional interruptions for longer operating

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(a) Facsimile Communication, Sharon Gorden, SDG&E. April 30, 1993, 9:00 a.m. PDT.
(b) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

periods. This analysis assumes an average interruption of 56 h/yr.[a] Incorporating this rate option requires a contractual agreement. The contract can be for a 1-year or 5-year term. Because the incentive is greater for the longer contractual agreement, this scenario assumes PWCSD will enter into 5-year contracts.

It is assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating. It is also assumed that each emergency generator is tested under no load approximately one hour each week and under full load approximately one hour each quarter,[b] in addition to operation at the request of SDG&E under the new rate option.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

2.19 Scenario 19: Utilize SDG&E Interruptible Schedule I-3, Rate A, with Scenario 14

Under this scenario, the cogeneration facility is modified as in Scenario 14, including the installation of the backup boiler. In addition, PWCSD incorporates the SDG&E Interruptible Schedule I-3, Rate A. This schedule is more fully discussed in Section 3.1. This rate schedule option provides a monthly credit to the electric utility bill. In return for this credit, PWCSD agrees to allow SDG&E to operate the emergency generators, at SDG&E's request, to reduce the NASNI electrical demand on the SDG&E system. This rate schedule, and its subject facilities, is used by SDG&E as another generating source when needed.

Schedule I-3, Rate A, allows SDG&E to give PWCSD 10-minutes' notice, by telephone, and start the emergency generators remotely. These interruptions typically occur less than 30 times per year for total engine operating hours of less than 80 h/yr. These are typical maximums according to SDG&E; however, the contract allows SDG&E to require additional interruptions for longer operating periods. This analysis assumes an average interruption of 56 h/yr.[a] Incorporating this rate option requires a contractual agreement. The contract can be for a 1-year or 5-year term. Because the incentive is greater for the longer contractual agreement, this scenario assumes PWCSD will enter into 5-year contracts.

It is assumed that the emergency-generator facility is staffed by one watch stander (WG-11) when the generators are operating. It is also assumed that each emergency generator is tested under

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(a) Facsimile Communication, Sharon Gorden, SDG&E. April 30, 1993, 9:00 a.m. PDT.
(b) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

no load approximately one hour each week and under full load approximately one hour each quarter,[a] in addition to operation at the control of SDG&E under the new rate option.

Part of the responsibility of the cogeneration staff is to monitor and operate the central chilled-water facility. Because the plant will not be staffed continuously, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The new system will be an expansion to the existing Johnson Controls system that currently monitors and controls much of the central HVAC system.

(a) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

3.0 Utility Rate Schedules

There are three energy sources affected by operating the cogeneration system: electricity, natural gas, and steam. The following is a discussion of these energy sources and their costs.

3.1 Electricity

Electric power is provided to NASNI from SDG&E under Schedule A6-TOU at the transmission rate. The current rate structure is shown in Table 3.1. Power generated by the NCTS cogeneration facility reduces the amount of power purchased from SDG&E. This avoided electric cost is treated as a savings, or positive cash flow, in the economic analysis.

In addition to standard electric service, the NCTS cogeneration facility is also subject to the SDG&E Schedule S standby service rate. This schedule is applicable to standby or breakdown service where all or part of the customer's electric requirements are supplied by a generation source other than the utility, which is located on the customer's premises. This schedule is not applicable to customers who have chosen, in the generation agreement, to sell power to the utility on a simultaneous purchase and sale basis. Because the NCTS cogeneration facility generates power for use at NASNI and does not sell energy to SDG&E, this schedule is applicable. The standby charge is $0.99/kW of contracted demand per month. The contracted demand is the full rated output, or nameplate rating, of the NCTS cogeneration facility, which is 2,600 kW (4 x 650 kW).

If the cogeneration facility is converted to an emergency-generator facility, it can incorporate the SDG&E Schedule I-3 Interruptible rate. This rate schedule provides a monthly credit to the NASNI electric utility bill for contracting with SDG&E to operate the generators on SDG&E's demand under special conditions, thereby interrupting a portion of SDG&E's demand. The period of interruption under this schedule can occur at any time at the utility's sole judgement, although special conditions usually do prevail. The utility can interrupt the load, requiring the engines to operate up to 30 times per year with a total interruption time usually below 80 h/yr, but not less than 5 h/yr. Scenarios 16 through 19 assume an average interruption of 56 h/yr. There are four rate options available under Schedule I-3 summarized in Table 3.2. Each rate option is available through 1-year or 5-year contracts. For purposes of this analysis, 5-year contracts are assumed.

3.2 Natural Gas

SDG&E provides natural gas to NASNI under the Schedule GPTCI rate. The cost of natural gas has a procurement component and a transportation component. In addition, the transportation component has a cogen rate and a non-cogen rate. The amount of natural gas applicable to the cogen rate is defined as the lesser of 1) the amount of gas used by the cogeneration equipment, and 2) the cogeneration gas allowance (CGA). The CGA is defined as the amount of gas required by the utility to generate and transmit an equivalent amount of electricity based on the utility's average annual incremental heat rate (IHR) (presently 10,688 Btu/kWh), which includes transmission line losses.

Table 3.1. Schedule A6-TOU Transmission Rate

	Summer	Winter
Customer Charge	$600.00	$600.00
Demand Charge:		
Per kW of noncoincident demand	$1.24	$1.24
Per kW of maximum demand at the time of system peak	$13.39	$2.17
Energy Charge:		
All on-peak kWh, per kWh	$0.06886	$0.06171
Plus all semi-peak kWh, per kWh	$0.04533	$0.03864
Plus all off-peak kWh, per kWh	$0.03369	$0.03186

Time Periods:

	Summer (May 1 through Sep 30)	Winter (Oct 1 through Apr 30)
On-Peak	11:00 a.m. - 6:00 p.m. weekdays	5:00 p.m. - 8:00 p.m. weekdays
Semi-Peak	6:00 a.m. - 11:00 a.m. weekdays	6:00 a.m. - 5:00 p.m. weekdays
	6:00 p.m. - 10:00 p.m. weekdays	8:00 p.m. - 10:00 p.m. weekdays
Off-Peak	10:00 p.m. - 6:00 a.m. weekdays	10:00 p.m. - 6:00 a.m. weekdays
	Plus weekends and holidays	Plus weekends and holidays

The cogeneration gas allowance is currently 0.107 therm/kWh, but has varied in the past. The natural gas consumed above the CGA is billed at the non-cogen rate. In addition to the transportation and procurement cost components, there is also a state regulatory fee.

These cost components can vary slightly from month to month as the price of natural gas fluctuates. The cost of natural gas used in this analysis is based on the 1992 cost components as billed, shown in Appendix B. Table 3.3 shows the average natural-gas costs for 1992.

To qualify for the cogen gas rate, the NCTS cogeneration facility must meet the qualified facility (QF) requirements as defined by the FERC. This qualification is done on an annual basis and presented to SDG&E. Calculations supporting the qualification based on 1992 data are located in Appendix C. If the cogeneration facility fails to qualify, all natural-gas consumption is charged at the non-cogen rate.

3.3 Steam

The NASNI steam loop supplies steam to the NCTS facility. NASNI is supplied 100-psig saturated steam from AEI under a custom contract. AEI operates another cogeneration facility nearby. Power and steam from AEI are provided to NASNI at very advantageous rates. The steam sales contract has 10 major components, several of which are basically fixed costs that are adjusted either quarterly or annually and are not related to the amount of steam consumed.

Table 3.2. Schedule I-3 Interruptible Rate Options

	Cancellation Period	
	1 Year	5 Years
Rate A:		
Applicable where the customer elects to provide utility-controlled interruptible load within ten minutes of notice of interruption.		
For each kW of guaranteed interruptible load, per month, per kW	$5.60	$7.06
Plus for each interruption during the monthly billing period, per kW	$0.28	$0.28
Rate B:		
Applicable where the customer elects to provide customer-controlled interruptible load within ten minutes of notice of interruption.		
For each kW of guaranteed interruptible load, per month, per kW	$5.15	$6.47
Plus for each interruption during the monthly billing period, per kW	$0.28	$0.28
Rate C:		
Applicable where the customer elects to provide utility-controlled interruptible load within thirty minutes of notice of interruption.		
For each kW of guaranteed interruptible load, per month, per kW	$4.15	$5.24
Plus for each interruption during the monthly billing period, per kW	$0.28	$0.28
Rate D:		
Applicable where the customer elects to provide customer-controlled interruptible load within thirty minutes of notice of interruption.		
For each kW of guaranteed interruptible load, per month, per kW	$3.80	$4.80
Plus for each interruption during the monthly billing period, per kW	$0.28	$0.28

Thermal energy generated and recovered by the NCTS cogeneration facility results in steam that would otherwise have to be purchased from AEI. This avoided steam cost is treated as a savings, or positive cash flow, in the economic analysis.

Because this analysis is concerned with the avoided cost of thermal energy, the fixed-steam costs are not considered. The avoided cost of steam consists of three components: feedwater cost, condensate return credit, and the energy adjustment credit. The feedwater cost is a straightforward charge of $1.73/Mlb of steam. The condensate credit reduces the steam charge based on the amount of condensate returned from NASNI and accepted by AEI, which is presently $1.59/Mlb. To date, this return rate has averaged 54% of the steam consumption. All steam consumed at the NCTS facility can be returned as condensate; however, there is the possibility of flash steam losses and leaks in the condensate return system. Condensate return is also regularly tested and screened by AEI for water quality. Condensate returned of unacceptable quality receives no credit. Therefore, the condensate

Table 3.3. Average Costs of Natural Gas for 1992

	Summer ($)	Winter ($)
Cogen Rate:		
Procurement	0.20559	0.18704
Transmission	0.09740	0.12114
Regulatory fee	0.00076	0.00076
Total, per therm	0.30375	0.30895
Non-Cogen Rate:		
Procurement	0.20559	0.18704
Transmission	0.14550	0.17842
Regulatory fee	0.00076	0.00076
Total, per therm	0.35185	0.36622
Seasons:		
Summer	April 1 through November 30	
Winter	December 1 through March 31	

credit is calculated to be 54% of $1.59/Mlb of steam consumed or $0.86/Mlb. The energy adjustment credit is more difficult to verify. A combined-cycle cogeneration facility is operated by AEI. Steam from that cogeneration facility is also used to generate electric energy. When less steam is extracted from the turbines to supply NASNI, AEI can use that steam to generate additional electric energy. One component of the energy adjustment credit is to return part of this opportunity savings back to NASNI. The energy adjustment credit varies and is updated quarterly. The avoided cost of this component is estimated to be $1.09 and $0.72/Mlb of steam during the summer and winter billing seasons, respectively.[a] The summer and winter seasons are the same as those in the SDG&E electric rate schedule.

Steam is delivered at 100-psig saturated vapor and condensate is passed at 100-psig saturated liquid. From the steam tables, the thermal energy available is 882 Btu/lb of steam. The avoided cost of steam is therefore $0.222/therm and $0.180/therm during the summer and winter billing seasons, respectively.

(a) Personal Communication, Robert Miner, SWDIV Code 1632.RM, and John Thomas, PWC Code 610. February 2, 1993, 3:00 p.m. PST.

4.0 Analysis

4.1 Cogeneration Operating Strategy

There are four basic operating strategies for controlling the load of a cogeneration system: base loading, electrical load following, thermal load following, and economic load following. These load strategies are discussed below.

4.1.1 Base Loading

Under this operating strategy, the cogeneration system runs at a fixed load, usually full-rated output. The cogeneration system usually meets only part of the electric or thermal energy requirements.

If the cogeneration system does not meet the electric or thermal energy requirements of the facility, the cogeneration system provides the facility base load while the electric utility provides any additional electric energy; and a supplemental thermal energy system, such as a boiler, provides any additional thermal energy requirements. If the cogeneration system does not meet the electrical load, additional electric energy is provided by the electric utility. If excess electric energy is generated, it is sold to the electric utility. Similarly, if the cogeneration system does not meet the thermal energy demand, additional thermal energy is provided from another source. If excess thermal energy is generated, it is exported or rejected to a heat sink such as a cooling tower.

4.1.2 Electrical Load Following

Under this operating strategy, the electrical output of the cogeneration system increases or decreases to meet the electric demand of the supported facility, making it independent of the electric utility. Therefore, the cogeneration output follows the facility's electric demand or load. Thus, this control strategy is referred to as "electrical load following." The resulting thermal energy that is recovered can be greater than or less than the thermal energy requirements. If more thermal energy is required, then a supplemental thermal energy system, such as a boiler, is needed to meet the demand. If excess thermal energy is available, then it must be exported or rejected to a heat sink such as a cooling tower.

4.1.3 Thermal Load Following

Under this operating strategy, the output of the cogeneration system increases or decreases to meet the thermal energy requirements of the supported facility. Therefore, the cogeneration output follows the thermal energy demand or load. Thus, this control strategy is referred to as "thermal load following." The electric energy generated can be greater than or less than the electric energy requirements of the facility. If more electric energy is required, the electric utility provides the remaining demand. If excess electric energy is generated, then it flows out into the electric grid and is thus sold to the electric utility.

4.1.4 Economic Load Following

With the advent of time-of-use and seasonal utility rates, the optimal cogeneration operating strategy may switch between base loading, electrical load following, or thermal load following from one period to the next because of the varying utility rates. Changing the active control strategy based on economic factors is referred to as "economic load following." For example, during the on-peak electric rate period, the optimal strategy may be electrical load following or base loading. However, during the off-peak electric rate period, when the cost of electric energy is much less, the optimal load strategy may be thermal load following. New computerized control systems can be programmed with current energy costs, make dynamic decisions as to which operating strategy is most economical, and automatically control the cogeneration system load to that optimal strategy.

4.1.5 Marginal Energy Cost Analysis and Selection of Optimal Load Operating Strategy

To determine which operating strategy is optimal for the NCTS cogeneration facility, a marginal energy cost analysis was performed. The marginal energy cost analysis utilized the costs that vary as a function of load, therefore, only energy costs were considered. Labor, materials, and maintenance costs were not considered in this analysis because they vary as a function of engine operating hours, but not necessarily as a function of engine load. The result of the marginal energy cost analysis does not determine whether or not it is cost effective to operate the cogeneration system; rather, it identifies at what load, or load strategy, the cogeneration system should operate.

Appendix D contains the marginal energy cost analysis, assuming the cogeneration facility qualifies for the SDG&E cogen gas rate. Appendix E contains the marginal energy cost analysis, assuming the cogeneration facility does not qualify for the SDG&E cogen gas rate, but rather for the non-cogen gas rate. In each of these analyses, there are two major cost categories: summer and winter. Within both of these categories, there are three minor subcategories: on-peak, semi-peak, and off-peak. There are more combinations because the definition of summer and winter seasons differ for the natural-gas utility and the electric utility, but only the primary combinations are considered in this analysis.

In Appendix D, Page D.4, the cost of the natural gas consumed is $22.63/h·engine with the engine running at full load during the summer on-peak time period. The value of the generated electric energy, excluding demand, is $41.32/h·engine and the value of the thermal energy, assuming 100% of the recoverable energy is utilized, is $7.84/h·engine. Because the value of the electric energy is greater than the value of the thermal energy, the electric energy is dominant. In addition, the value of the electric energy is more significant than the cost of the natural gas. Therefore, the engine should run at base (or full) load when in operation.

During the winter semi-peak period, however, the cost of the natural gas consumed is $23.10/h·engine; the value of the electric energy generated at full load, excluding demand, is $23.18/h·engine; and the value of the thermal energy, assuming 100% of the recoverable energy is utilized, is $6.36/h·engine. The electric energy is still dominant over the thermal energy, but in itself is not greater than the cost of the natural gas. Under these conditions, the optimal load control strategy is electrical load following.

The marginal energy cost analyses located in Appendix D and Appendix E can be used to determine the net energy savings that result from various combinations of the NCTS facility electrical and thermal requirements. Generally, a base loading control strategy is indicated, although in some circumstances electrical load following offers some minor improvement in economics. Therefore, economic load following would be the optimal control strategy with base loading a close second. Unfortunately, there is no electric consumption data available from the NCTS facility. For this reason, all of the alternative scenarios consider the base load operating strategy. If the NCTS facility electric submetering demand and consumption information becomes available, the calculations can be re-evaluated for an economic load following control strategy.

4.2 Determining the Thermal Load of the NCTS Facility

A major component of this analysis is the thermal energy recovered and used from the cogeneration facility, which requires an understanding of the thermal load of the NCTS facility. The following sections estimate the existing thermal load of the facility and its anticipated growth.

4.2.1 Present Thermal Load

There are four thermal energy requirements within the NCTS facility: building cooling, reheat, building heat, and DHW. Cooling is provided by absorption chillers. There are three 400-ton absorption chillers in the NCTS facility. The peak cooling load, however, is estimated to be approximately 300 tons. Cooling is required throughout the year. Although not submetered, the facility maintains detailed log records on the cooling energy requirements. This information is used to calculate the useful thermal energy to qualify for the SDG&E cogen gas rate. The required thermal energy for the cooling load can be estimated from the Cogeneration Data Summary (see Appendix C) and the PWCSD Metered Utility Report for steam (see Appendix A). This information is summarized in Table 4.1. The required thermal energy for the cooling load during the AEI summer billing period is approximately 176,330 therms/yr and during the winter billing period is approximately 234,460 therms/yr. There are no records, however, of the thermal energy requirements for the reheat, heating, or DHW systems.

Because the DHW system is not submetered, the energy requirements for this thermal load are estimated using energy-use intensities (EUIs) based on national estimates. The EUIs used for DHW are shown in Table 4.2. The NCTS facility consists of three major categories: 1) administration, computer and telecommunications area (office), 2) warehouse, and 3) the cogeneration plant (miscellaneous). The gross floor areas of the office, warehouse and cogeneration plant are 31,425, 53,550, and 10,350 ft^2, respectively. Using the EUIs for these categories, the DHW energy requirements are estimated to be 9,980 therms/yr. This thermal load is divided between the AEI summer and winter billing periods based on the number of operating hours in each period. Therefore, the DHW load during the summer billing period is 4,183 therms/yr and during the winter billing period is 5,797 therms/yr.

No information is available for the heating or reheat loads of the NCTS facility. Since its original construction, the internal heat gain of the NCTS facility has significantly changed, mainly because of the miniaturization of computers. Therefore, the original facility construction documents

Table 4.1. Thermal Energy Requirements for Cooling

1992 Month	AEI Season	Cogen (therms)	Steam (therms)	Total (therms)
Jan	W	38,440	11,460	49,900
Feb	W	13,630	14,870	28,500
Mar	W	24,370	12,570	36,940
Apr	W	17,910	15,480	33,390
May	S	22,430	16,110	38,540
Jun	S	25,360	11,930	37,290
Jul	S	24,260	9,860	34,120
Aug	S	28,260	5,750	34,010
Sep	S	21,120	11,250	32,370
Oct	W	27,700	3,620	31,320
Nov	W	26,800	350	27,150
Dec	W	26,830	430	27,260
Summer		121,430	54,900	176,330
Winter		175,680	58,780	234,460
Total		297,110	113,680	410,790

Table 4.2. Energy-Use Intensities for Domestic Hot Water

Office	14.6 kBtu/ft^2·yr
Warehouse	8.6 kBtu/ft^2·yr
Miscellaneous	7.6 kBtu/ft^2·yr

can no longer be used to estimate the facility heating load or the reheat energy requirement estimate. The NCTS facility can still be classified as a thermally heavy building, meaning that there are significant internal heat gains. This is supported by documented cooling requirements that indicate the facility requires cooling throughout the year; thus, the heating and reheat loads are assumed to be negligible. This may be a weak assumption and has minimal impact on the overall economic analysis.

Referring to the energy analysis calculations discussed in Section 4.3.1 for Scenario 1 (status-quo operation), if the total required thermal energy estimate were to be off by as much as 25%, the net energy savings would be off by only approximately 10%. Because the cooling load is by far the largest thermal energy load, the estimate of the total thermal energy requirements should be

reasonably accurate. The NCTS cogeneration facility is currently installing additional metering capabilities. If more accurate thermal energy consumption information becomes available, this assumption may be revised.

4.2.2 Growth of Thermal Load

The U.S. Department of Defense (DoD) is presently undergoing a phase of reduction and consolidation and this trend is anticipated to continue. The resulting impact to NASNI is internal growth. This growth will impact the NCTS facility and, therefore, the cogeneration facility. It has been estimated that the average electrical load of the NCTS facility will increase from the present 1,100 kW to a projected 2,000 kW at about 3%/yr.[a]

The facility's cooling requirements will increase as the electric load increases. The increased electrical consumption in the NCTS facility will directly increase the internal heat gain. The increasing load will also be accompanied by additional personnel within the facility. For these reasons, it is assumed that the required thermal energy (i.e., cooling and DHW) from the cogeneration system will also increase at the same rate as the estimated electrical load. If there had been estimates for building heating and reheating, these loads would decrease as the internal heat gains increased until they were no longer applicable. Thermal energy analysis projections are located in Appendix F. These projections consider the growth in thermal energy requirements for the NCTS facility and the impact on the thermal energy recoverable from the cogeneration facility under Scenarios 1 through 12.

Scenarios 1, 2, and 3 become inadequate to meet the required electrical load under this anticipated growth. Because the cogeneration facility is interconnected to the SDG&E electric grid, there is no problem during normal operation. However, if an emergency shutdown or failure of the SDG&E electrical system were to occur, the cogeneration facility may not be capable of supplying the entire NCTS facility as early as 1995 (see Appendix F, p. F.2).

4.3 Engineering and Economic Analysis

The following sections discuss the engineering and economic analysis of the alternative scenarios. This includes the energy analysis calculations, operations and maintenance (O&M) costs, emissions and related costs, implementation costs, and finally the life-cycle cost analysis.

4.3.1 Energy Analysis Calculations

A spreadsheet was designed to analyze the energy and energy cost information obtained from the operation of the NCTS cogeneration facility under a base loading control strategy. This information is summarized in Table 4.3. The calculations are included in Appendix G.

(a) Personal Communication, Robert Miner, SWDIV Code 1632.RM.

Table 4.3. Summary of Energy and Energy Cost Information - NCTS Facility Under Base Loading Control Strategy

Scenario	Natural-Gas Energy Consumed (therms/yr)	Electric Energy Avoided (kWh/yr)	Steam Energy Avoided (therms/yr)	Qualify Cogen Gas Rate (Y or N)	Natural Gas Cost ($/yr)	Electric Energy Savings ($/yr)	SDG&E Backup Cost ($/yr)	Thermal Energy Savings ($/yr)	Net Energy Savings ($/yr)
1	1,224,819	9,757,764	294,539	Y	381,685	504,265	30,888	58,444	150,136
2	570,464	4,544,712	137,163	Y	177,763	334,150	30,888	27,197	152,696
3	166,245	1,324,427	40,309	Y	51,681	184,976	30,888	8,344	110,751
4	2,528,652	20,145,000	408,281	N	901,752	1,033,644	30,888	81,014	182,018
5	1,177,728	9,382,603	190,132	N	419,959	682,439	30,888	37,699	269,291
6	343,215	2,734,293	55,875	N	121,806	375,605	30,888	11,566	234,477
7	2,247,386	20,480,750	408,281	Y	686,518	1,050,872	28,987	81,014	416,381
8	1,046,728	9,538,979	190,132	Y	319,737	693,813	28,987	37,699	382,788
9	308,039	2,779,864	55,875	Y	92,992	381,865	28,987	11,566	271,452
10	3,949,997	25,852,750	408,281	N	1,408,623	1,326,510	36,590	81,014	(37,689)
11	1,839,724	12,041,007	190,132	N	656,016	875,796	36,590	37,699	220,889
12	536,135	3,509,009	55,875	N	190,272	482,027	36,590	11,566	266,731
13	7,185	0	0	N	2,418	0	0	0	(2,418)
14	7,185	0	0	N	2,418	0	0	0	(2,418)
15	7,185	0	0	N	2,418	0	0	0	(2,418)
16	24,675	134,400	0	N	8,180	148,839	0	0	140,659
17	24,675	134,400	0	N	8,180	213,927	0	0	205,747
18	24,675	134,400	0	N	8,180	148,839	0	0	140,659
19	24,675	134,400	0	N	8,180	213,927	0	0	205,747

The calculations in Appendix G can be divided into four main sections. The first section identifies the cogeneration specifications and the operating schedule. The number of engines typically operating, their electrical output capacity, the SDG&E backup contracted demand, engine generator heat rate, and recoverable thermal energy are identified in this section. The heat rate is the amount of input fuel required to generate 1 kWh of electric energy and is based on the HHV of the fuel. The thermal energy recovery is the amount of thermal energy that can be recovered from the cogenerator as a percentage of input fuel.

The cogeneration operating schedule identifies when the cogeneration system operates. The schedule corresponds to the SDG&E electric utility rate schedule. Additional information includes the total available operating hours (8,760 h/yr), the scheduled downtime, and the resulting net operating hours. Scheduled downtime is for normal engine maintenance and overhauls. The net utilization of hours is the net operating hours divided by the available operating hours. The load utilization factor is the average percent load of the engine generators. Under the base loading strategy, the load utilization factor should be 100% or full load. The powerhouse load is the estimated electric energy consumption within the cogeneration facility as part of the cogeneration process. The powerhouse load, 1.25%, is identified as a percentage of total electrical output from the cogeneration engines. This number was estimated from PWCSD metered utility reports (see Appendix A) during 1992.

The second section of the analysis reiterates the utility rate schedule and unit cost factors as discussed in Section 3.1. These schedules and unit costs are necessary to calculate the resulting costs and savings associated with operating the cogeneration facility.

The third section contains the resulting energy calculations. This section is divided into the various energy categories. Natural gas consumed by the cogeneration engines is identified at the top of this section. The spreadsheet automatically determines if the facility qualifies for the cogen or non-cogen natural-gas rates (by calculating and examining the FERC efficiency) and applies the appropriate cost factors.

Gross electricity generated and net energy generated are then identified. The net electricity generated takes into account the electrical energy consumed as part of the powerhouse load.

The analysis then considers the thermal energy systems. The thermal energy recoverable is the amount of heat energy that can be recovered from the cogeneration system. The required thermal energy is the thermal demand of the NCTS facility, as discussed in Section 4.2, consisting of comfort cooling, comfort heating, reheat, and DHW. The analysis then estimates the thermal energy recoverable and useable. Because thermal energy storage is not possible, the thermal energy recovered must correspond with the thermal energy demand.

The final section of the analysis summarizes the energy costs and savings resulting from the operation of the cogeneration facility. In addition, the annual FERC efficiency is identified.

Appendix G contains the analysis for each of the scenarios concerning continued operation of the cogeneration facility. The scenarios that involve converting the cogeneration facility into an emergency-generator facility were determined separately. Because emergency downtime is a

nonroutine occurrence, it can rarely be anticipated. This analysis assumes that emergency downtime does not actually occur. Under these conditions, no electric cost or steam cost is reduced. Natural gas however is consumed during the routine scheduled testing of the engines.

Under Scenarios 16 through 19, there would be reduced electric energy purchased when the SDG&E interruption occurs. In addition, there may or may not be any resulting peak demand reduction. Because these interruptions can occur at any time, and for any duration, the results are difficult to estimate. For this analysis, it is assumed that the interruptions will occur, on average, 56 h/yr over two months during the summer on-peak billing period. In addition to the interruptible rate credit, savings are calculated for the avoided energy consumption. Because NASNI peak demand typically occurs during the semi-peak period, no demand reduction savings are claimed.

4.3.2 Operations and Maintenance Costs

The O&M costs are divided into the following six cost categories, except in the gas turbine and emergency-generator alternatives where maintenance costs are combined: PWCSD labor, PWCSD general maintenance, catalytic converter, subcontractor preventive maintenance, subcontractor corrective maintenance, and subcontractor engine overhaul. Each of these cost categories has a significant impact on the overall economics of operating the cogeneration facility as shown in Table 4.4.

4.3.2.1 Labor Costs

Staffing requirements for PWCSD were noted in the discussion of alternative scenarios in Section 2.0. Staffing requirements were divided into three categories for the cogeneration alternatives: continuous operation, operate on-peak and semi-peak periods, and operate on-peak period. For continuous operation, PWCSD has requested staffing consist of one foreman on the day shift, one maintenance mechanic (WG-10) on the day shift, and five watch standers (WG-11) for rotating shifts.[a] At current PWCSD labor rates, this equates to a total labor charge of $309,254 per year. This staffing level is associated with alternative Scenarios 1, 2, 3, 4, 7, and 10.

For noncontinuous operation of the cogeneration system, additional assumptions are made. PWCSD standard work shifts do not coincide with SDG&E time-of-use periods. It is assumed that PWCSD will staff the cogeneration facility one-half hour before the SDG&E operational period begins and will relocate staff one-half hour after the SDG&E operational period ends, requiring PWCSD staff to work partial days in the cogeneration facility and partial days elsewhere on the base.

For operation during the on-peak and semi-peak periods, PWCSD staffing is assumed to be one foreman on the day shift, one maintenance mechanic (WG-10) on the day shift, and one watch stander (WG-11) present one-half hour before scheduled operation until one-half hour after scheduled shutdown. The on-peak and semi-peak periods occur 16 h/d, Monday through Friday, excluding holidays for both the summer and winter seasons. At current PWCSD labor rates, this equates to a total labor charge of $265,980 per year. This staffing level is associated with alternative Scenarios 5, 8, and 11.

(a) Personal Communication, Robert Miner, SWDIV Code 1632.RM, and John Thomas, PWC Code 610. February 2, 1993, 3:00 p.m. PST.

Table 4.4. Summary of Operations and Maintenance Costs

Scenario	Operating Hours (h/yr)	Total Engine Run Hours (h/yr)	PWC General Maintenance ($/yr)	Catalytic Converter ($/yr)	Subcontractor Preventive Maintenance ($/yr)	Subcontractor Corrective Maintenance ($/yr)	Subcontractor Engine Overhaul ($/yr)	Total Maintenance ($/yr)	Total PWC Labor ($/yr)
1	8,760	17,520	60,000	60,000	92,196	19,200	26,609	258,005	309,254
2	4,080	8,160	60,000	27,945	92,196	8,942	12,393	201,477	309,254
3	1,189	2,378	60,000	8,144	92,196	2,606	3,612	166,558	309,254
4	8,500	34,000	60,000	116,438	92,196	18,630	51,639	338,904	309,254
5	3,959	15,836	60,000	54,233	92,196	8,678	24,052	239,159	265,980
6	1,154	4,616	60,000	15,808	92,196	2,530	7,011	177,545	154,610
7	8,500	34,000	60,000	116,438	92,196	18,630	51,639	338,904	309,254
8	3,959	15,836	60,000	54,233	92,196	8,678	24,052	239,159	265,980
9	1,154	4,616	60,000	15,808	92,196	2,530	7,011	177,545	154,610
10	8,500	17,000	60,000	n/a	199,497	n/a	n/a	259,497	309,254
11	3,959	7,918	60,000	n/a	137,340	n/a	n/a	197,340	265,980
12	1,154	2,308	60,000	n/a	98,951	n/a	n/a	158,951	154,610
13	52	208	60,000	n/a	2,000	n/a	n/a	62,000	4,327
14	52	208	60,000	n/a	2,000	n/a	n/a	62,000	4,327
15	52	208	60,000	n/a	2,000	n/a	n/a	62,000	4,327
16	108	432	60,000	n/a	4,400	n/a	n/a	64,400	5,711
17	108	432	60,000	n/a	4,400	n/a	n/a	64,400	5,711
18	108	432	60,000	n/a	4,400	n/a	n/a	64,400	5,711
19	108	432	60,000	n/a	4,400	n/a	n/a	64,400	5,711

For operation during the on-peak period only, PWCSD staffing is assumed to be one foreman, one maintenance mechanic (WG-10), and one watch stander (WG-11) present one-half hour before scheduled operation until one-half hour after scheduled shutdown. The on-peak period occurs for 7 h/d, Monday through Friday during the summer season, excluding holidays, and for 3 h/d, Monday through Friday during the winter season, excluding holidays. At current PWCSD labor rates, this equates to a total labor charge of $154,610 per year. This staffing level is associated with alternative Scenarios 6, 9, and 12.

If the cogeneration facility is converted to an emergency-generator facility, staffing will occur during an outage and when engines are tested. Because, for purposes of this analysis, it has been assumed that outages will not normally occur, no labor costs are associated with this event. During the scheduled engine tests, staffing requirements are estimated to be one watch stander (WG-11) for approximately four hours for each test. Under the directive of NCTS, there will be 48 no-load tests (one per week, except for quarterly full-load tests) and four full-load tests (one per quarter).[a] At current PWCSD labor rates, this equates to a total labor charge of $4,327 per year. This staffing level is associated with alternative Scenarios 13, 14, and 15.

Under Scenarios 16 through 19, the emergency generators are assumed to operate approximately 56 h/yr in addition to the routine scheduled load tests. Assuming that interruption occurs 7 times per year, 8 hours per interruption, and that staff would arrive one-half hour before and depart one-half hour after interruption, the PWCSD labor cost for this scenario would be $5,711 per year.

4.3.2.2 Maintenance Costs

PWCSD performs maintenance on the cogeneration facility, including the chiller plant, beyond that covered by the Pentech preventive maintenance contract. During 1992, these general maintenance costs were $60,000. Maintenance costs can usually be related to the equipment run time. However, these maintenance costs are associated with the HVAC and auxiliary equipment, which will continue to operate in a similar fashion, and are therefore treated as a fixed cost.

The cogeneration engines have two catalytic converters in series. These catalytic converters are replaced after one year of operation at a cost of $15,000 each. The annual cost of the catalytic converters is also assumed to be a function of engine operating hours for Scenarios 1 through 9. In the emergency-generator alternatives, the life of the catalytic converters also is assumed to be a function of engine run time.

The maintenance requirements for the cogeneration engines are subcontracted by PWCSD. These maintenance requirements include: preventive maintenance, nonroutine maintenance, and engine overhauls. Although the cost of preventive maintenance should also be a function of operating hours, this is a point of contract negotiation. For the purpose of this analysis, it is assumed to be a fixed cost of $92,196 per year for Scenarios 1 through 9.

(a) Facsimile Communication, John Thomas, PWC Code 610, for Douglas McDaniel, NCTS SD N42. May 4, 1993, 9:10 a.m. PDT.

Corrective maintenance consists of special incidents. During the previous year, the cogeneration facility experienced around two incidents per month at a cost of $800 per incident. These incidents are further outlined in Appendix I. The frequency of incidents is assumed to be a function of equipment run time for Scenarios 1, 2, and 3. Under the repair and replacement options (Scenarios 4 through 9), the incident rate is assumed to be 50% less or one incident per month.

The reciprocating engine generators are overhauled after every 20,000 h of engine run time, which is under contract to Pentech at a cost of $30,376 per engine. This equates to an average cost of $1.52 per engine run-hour, which is used to estimate the overhaul cost of each of the scenarios involving reciprocating engines.

The maintenance cost estimated for the gas turbine options is not separated into multiple categories. The total maintenance costs for the gas turbine scenarios are identified in the subcontractor preventive maintenance column in Table 4.4. The estimated maintenance costs are based on another gas turbine cogeneration facility located at the Naval Regional Medical Center (Zavala and Heller 1991). The hospital has three natural-gas-fired 800-kW solar gas turbine generators. Maintenance costs at this facility are also subcontracted. This annual contract fee includes monthly visits, routine maintenance, emergency visits, overhauls, parts (except oil and filters), and contractor labor. The maintenance cost estimates for Scenarios 10, 11, and 12 were prorated based on operating capacity and engine run hours. These costs correlate well with maintenance costs found in California Energy Commission sources (CEC 1991).

The total maintenance costs for the emergency-generator options (Scenarios 13 through 19) are also identified in the subcontractor preventive maintenance column in Table 4.4, although it is assumed that all maintenance on the emergency generators would be performed by PWCSD personnel. The total maintenance costs for these options are derived from other PNL studies of emergency-generator facilities (Richman et al. 1993; Dixon et al. 1992). The annual maintenance costs for Scenarios 13, 14, and 15 are estimated to be $2,000. Scenarios 16 through 19 require additional operating hours, therefore the annual maintenance costs are estimated to be $4,400. Maintenance cost for the backup boiler system of Scenarios 14, 15, 18, and 19 are assumed to be negligible.

4.3.3 Emissions and Related Costs

4.3.3.1 Summary of Findings

The emissions costs associated with the NCTS cogeneration plant fall into two categories: the annual permitting cost and the opportunity cost of the emissions permits. The annual permitting cost is a fee paid directly to SDAPCD and is estimated at about $10,724 per year. This fee would be discontinued if the plant were shut down and so represents a plant operating cost. In addition to this fee, there is the opportunity cost of operating the plant, which is derived from the emissions permits held by the plant. This opportunity cost is the value that could be obtained from the sale of the right to emit regulated pollutants. When the plant is operating, these rights must be held by the USN. If the plant were to reduce its level of operation or be closed down, some or all of these rights could be sold or saved for use on a different pollution emitting project. In either case, the closure or reduced operation of the plant would result in the production of a set of emissions permits with a market value. This market value is estimated to be at least $400,000 if the plant were closed, which should

be treated as a one-time lump sum obtained after the plant closure. If the plant were not closed but reduced its level of operation, the value of the saleable permits would be proportionally less. The permits should be valued at the market value, even if the USN were to save the permits for their own use, because possession of the permits would save the USN from having to purchase permits on the open market. For a more thorough discussion on emissions trading, see Appendix C in *Economic Analysis of Operating Alternatives for the South Vandenberg Power Plant at Vandenberg Air Force Base, California* (Daellenbach et al. 1993).

4.3.3.2 Description of SDAPCD Regulations

Permit schedules vary depending on the type and size of a facility. The schedule that the NCTS plant falls under charges an annual renewal fee per engine. The renewal fee covers all costs involved with testing and emissions fees and represents an average of the cogeneration plants of a given size.[a] This fee changes from year to year because it is calculated by dividing the number of engines tested into the total cost of testing, with a two-year lag.[b] In other words, changes in testing costs and engine population for 1991 will be reflected in the renewal fee for 1993. If an engine is going to be taken off line, the plant owner has two choices: the emissions can be banked or traded, or the engine can go to a nonoperational status.

For the emissions to be banked or traded, credits must be issued by SDAPCD. The number of credits is determined by the actual emission output of the engine averaged over the last two years of operation. Credits are only issued for emissions reductions that are real and permanent.[c] The value of these credits is uncertain because of the newness of the market and the limited number of market transactions that have occurred. The value of the credits is also affected by whether the district is in attainment for a given pollutant; that is, whether the measured pollutants within the district meet state or federal limits. Within SDAPCD, the only pollutant in attainment is sulfur oxides (SOx). The district is in nonattainment for nitrogen oxides (NOx), particulate matter (PM), carbon monoxide (CO), and reactive organic compounds (ROCs).[d] Both attainment and nonattainment pollutants can be traded; however, district nonattainment pollutant levels imply a greater value for those credits.

Another alternative that the plant owner has is to place the engine on nonoperational status. The nonoperational status fee allows the owner to maintain the emissions permit in the event that the owner may want to bring the engine back on line.

(a) Personal Communication, Barney McIntire, San Diego Air Pollution Control District. February 23, 1993, 9:00 a.m. PST.

(b) Personal Communication, John Savel, Code 950B Public Works Center, Environmental Division. March 4, 1993, 9:45 a.m. PST.

(c) Personal Communication, Dan Speer, San Diego Air Pollution Control District. February 23, 1993, 8:30 a.m. PST.

(d) Personal Communication, Alberto Abreu, San Diego Air Pollution Control District. October 27, 1993.

4.3.3.3 The NCTS Cogeneration Plant

The NCTS cogeneration plant consists of four 650-kW Caterpillar engines operated as rich burn using natural gas with a propane backup fuel supply, which are operated by PWCSD. Currently, the NCTS plant operates two engines continuously while maintaining a third engine for backup power. The engines are permitted for operation at 600 kW, with a minimum operation level of 580 kW and a maximum level of 620 kW (see Appendix H) for natural-gas usage with diesel oil backup.[a] The engines were permitted at 600 kW instead of 650 kW because that is the maximum power level that the engines were able to achieve when tested.[b]

The engines are tested at least once a year by SDAPCD. According to the permits, each engine can emit up to 215 ppmv of NOx and up to 350 ppmv of CO. If an engine fails the emissions test, a notice of violation is issued and a fine is assessed. The plant operator will then shut down the violating engine to avoid additional fines, and begin the process of correcting the problem. Once the correction is made, an independent testing firm is brought in to retest the engine and SDAPCD sends an observer. After submission of a final report, the plant operator must go before a hearing board to ask that a variance be granted before the engine can be restarted. Operation of the engine during this time can result in large fines. Once the variance has been granted, the operator can bring the engine back to full operational status.[b]

The NCTS plant has received six to eight notices of violation in the past. The plant has been in compliance for the past year, however, primarily because of the purchase and use of a portable tester. The tester monitors the engine emissions so that problems can be quickly identified and corrected to avoid further violation notices.[b] For this reason, the variable costs associated with violation notices were not included in the analysis because it was assumed that the use of the portable tester would prevent future notices of violation.

4.3.3.4 Development of Environmental Cost Estimate

Each year, the NCTS must renew the permits on each of the operating engines. Currently, the permit fee for 1993 is $2,681 per engine. If the NCTS plant decides to take an engine off line but retain the permits, the cost will be $147 per engine per year. Calculating the opportunity cost of operating the engines is more complicated.

Table 4.5 summarizes the emissions per engine for 1991.[c] SDAPCD does not test for SOx, and ROCs are a subset of total organic compounds (TOCs). Engines are identified by permit number, and pollutant levels are listed in tons.

(a) Personal Communication, John Savel, Code 950B Public Works Center, Environmental Division. March 4, 1993, 9:45 a.m. PST.

(b) Personal Communication, John Savel, Code 950B Public Works Center, Environmental Division. March 2, 1993, 8:15 a.m. PST.

(c) Personal Communication, Clay Hinkle, San Diego Air Pollution Control District. March 3, 1993, 4:30 p.m. PST.

In 1991, however, the emissions of NOx and CO exceeded the permitted level, resulting in fines. Only actual, permitted emissions can be traded, so the potentially available credits are less than shown in Table 4.5. Table 4.6 shows the level of potentially available credits.

Assuming that these totals represent continuous operation of two engines, and that this level of operation would be maintained for 2 years prior to any shutdown, the next step is to assign a value to the available credits. Table 4.7 contains the best estimates of existing market prices for emission credits (Daellenbach et al. 1993).

Table 4.5. 1991 Annual Emissions Per Engine

Pollutant	Engine 860537 (tons)	Engine 860538 (tons)	Engine 860539 (tons)	Engine 860540 (tons)	Total (tons)
Nox	1.8	1.7	20.1	17.2	40.8
TOC	1.2	3.5	8.3	4.6	18.2[a]
ROC	0.3	0.9	2.1	1.2	5.1[a]
CO	0.2	1.3	2.5	3.3	7.3
PM	—	0.1	0.1	0.1	0.3

(a) Totals for TOC and ROC include 0.6 ton for metals coding.

Table 4.6. Potentially Available Emissions Credits

Pollutant	Credit (ton/yr)
NOx	34.4
ROC	5.1
CO	7.3
PM	0.3

Table 4.7. Estimated Value of Emission Reduction Credits

Pollutant	Value ($/ton)
ROC	20,000
NOx	10,000
SOx	400
CO	400
PM	400

The $20,000 price per ton for ROC is based on an actual sale that occurred in Ventura County Air Pollution Control District. The $10,000 price per ton for NOx is a prediction based on the ROC sales price and the price of control technologies. There is a low but nonzero estimated price for SOx, although it is not a regulated pollutant. This is presumably because of some speculative demand to offset potential future regulations. While CO is regulated in SDAPCD, it is not in the Santa Barbara Air Pollution Control District; the district for which these figures were estimated. The $400 price per ton from Santa Barbara is used here; however, it probably represents a lower bound estimate. These price estimates are very rough and should be treated as approximate lower bound estimates because this is a new, highly volatile market. As an example of the volatility, consider the experience in one district where an owner was made an offer of $1,000,000 for five tons of SOx credits. The owner decided to keep the credits.[a]

By combining the information in Tables 4.6 and 4.7, the estimated value of permits held by the NCTS cogeneration plant is $449,040 (see Table 4.8). This value would only be realized if the plant were to shut down entirely. Table 4.9 shows the value of the emissions permits used for each scenario based on their hours of operation. Table 4.9 also shows the value of the renewal fee, which is based on the number of permitted engines.

Table 4.8. Value of Emissions Permits

Pollutant	Ton	Value ($/ton)	Estimated Value ($)
ROC	65.1	20,000	102,000
NOx	34.4	10,000	344,000
CO	7.3	400	2,920
PM	0.3	400	120
Total	41.4		449,040

(a) Personal Communication, Bill Anderson, EMC Inc., February 25, 1993, 10:00 a.m. PST.

Table 4.9. Value of Renewal Fee and Emissions Permits for the Life-Cycle Cost Analysis

Scenario	Engine Operation (h/yr)	Renewal Fee ($/yr)	Emissions Permit Value[a] ($)
1	8,760	10,724	0
2	4,080	10,724	223,898
3	1,189	10,724	388,092
4	8,500	10,724	13,328
5	3,959	10,724	246,101
6	1,154	10,724	389,886
7	8,500	10,724	13,328
8	3,959	10,724	246,101
9	1,154	10,724	389,886
10	8,500	5,362	13,328
11	3,959	5,362	246,101
12	1,154	5,362	389,886
13	52	1,060	446,374
14	52	1,060	446,374
15	52	1,060	446,374
16	108	1,060	443,504
17	108	1,060	443,504
18	108	1,060	443,504
19	108	1,060	443,504

(a) Must obtain new permit to operate at reduced level, and operate at the reduced level for two years before the value of emissions permits can be realized. Therefore, the proposed cash flow will occur in 1997.

4.3.4 Implementation Costs

The 19 scenarios can be divided into five main groups for implementation costs, which are status-quo, repair the existing engines, replace the engines with new reciprocating engines, replace the engines with new gas turbines, and convert the facility to emergency-generator status.

Scenarios 1, 2, and 3 are status-quo alternatives. There are no implementation costs for these alternatives. The engines continue to operate in their existing condition.

Scenarios 4, 5, and 6 are repair alternatives. The Energy Technology Engineering Center (ETEC) was commissioned by PNL to further evaluate the condition of the existing cogeneration facility to identify necessary repairs required to bring the facility up to original specifications. The ETEC report is located in Appendix I. Repair costs are estimated to be $54,525, which includes replacing the load-sharing and speed controls; the air-fuel ratio controller; service and tune-up of the governor actuators, Caterpillar engines; switch gear; and some electrical and instrumentation rewiring. In addition to the repairs to the engines and controls, PNL has also identified necessary modifications to the electrical switchgear, which is included in the implementation cost estimate. Because the plant will not be staffed continuously in Scenarios 5 and 6, the chilled-water system will be equipped with new automated valves and controls to better control the system and respond to equipment failures. Should a chiller, cooling tower, or pump fail, the new control system will shut down the failed component and automatically start another. The cost of this modification, including materials, labor, equipment, and engineering fees, is estimated to be $35,950.

Scenarios 7, 8, and 9 assume the existing engines are replaced with new reciprocating engines. The total implementation cost for this set of alternatives is estimated to be $1,830,000, which includes removing the existing engines and generators, purchasing new reciprocating engine generators, delivery, and installing and commissioning the new system (Rodden et al. 1986; Gerber 1988; CEC 1991). It is assumed that the salvage value of the existing engines would cover the cost of their removal. The existing waste heat recovery equipment is still used under these scenarios as discussed in Section 2.0. In addition to replacing the engines and controls, PNL has also identified necessary modifications to the electrical switchgear, which is included in the implementation cost estimate. Because the plant will not be staffed continuously in Scenarios 8 and 9, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. The cost of this modification, including materials, labor, equipment, and engineering fees, is estimated to be $35,950.

Scenarios 10, 11, and 12 consider replacing the existing cogeneration system with a new gas turbine cogeneration system. Implementation of this alternative is estimated to be $5,554,000, which includes removing the existing engines, generators, and waste heat recovery equipment; purchasing new gas turbines with generators and waste heat recovery equipment; delivery; installing and commissioning the new system; and training PWCSD personnel on the O&M of the new system (Rodden et al. 1986; Gerber 1988; CEC 1991). In addition to replacing the cogeneration system, PNL has also identified necessary modifications to the electrical switchgear, which is also included in the implementation cost estimate. Because the plant will not be staffed continuously in Scenarios 11 and 12, the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. The cost of this modification, including materials, labor, equipment, and engineering fees, is estimated to be $35,950.

Scenarios 13, 16, and 17 assume the cogeneration facility is converted to an emergency-generator facility. In addition to the repairs noted in the repair alternatives described earlier (Scenarios 4, 5, and 6), it is estimated that additional servicing and conversion will be required (see Appendix I). The total implementation cost for these scenarios is estimated to be $100,425.

Scenarios 14, 18, and 19 involve repairing the engines as described for Scenario 13, as well as installing a new 11.5 MBtu/h (output) boiler (approximately 350-boiler hp) to back up the AEI steam

system. The new boiler is required to supply the peak thermal energy requirements of the NCTS facility, including the forecasted growth. The total implementation cost for this scenario is estimated to be $259,250.

Scenario 15 involves replacing the entire cogeneration system with a new emergency-generator system and new backup boiler. Implementation of this alternative is estimated to be $2,024,725, which includes removing the existing engines and generators, abandoning-in-place the waste heat recovery equipment, purchasing new emergency generators, purchasing the new boiler, installing new automated valves and controls, and installing and commissioning the new system.

Because the plant will no longer be staffed in any of the emergency-generator scenarios (Scenarios 13 through 19), the chilled-water system will be equipped with new automated valves and controls to respond to equipment failures. The cost of this modification, including materials, labor, equipment, and engineering fees, has been included in the implementation cost estimates. A summary of the implementation costs for all scenarios is shown in Table 4.10.

As noted in Sections 2.13 through 2.19, the emergency generators are to be tested under no load approximately one hour each week and under full load approximately one hour each quarter. Load banks are not included in the implementation cost estimate. Full-load tests will be accomplished by connecting the generators to the electric grid. The new engine controls are capable of automatically synchronizing with the electric grid.

4.3.5 Life-Cycle Cost Analysis

The alternative scenarios described in this report were evaluated on the basis of their life-cycle costs. Federal agencies are required to evaluate energy-related investments on the basis of minimum life-cycle costs (10 CFR 436). The life-cycle cost of an investment is the present value of all costs associated with the investment over time. The cost elements cannot simply be summed up when calculating the life-cycle cost because costs occurring at different points in time need to be treated differently (NBS 1987). This is accomplished through discounting using the federally mandated discount rate of 4.0% (NIST 1992) and fuel escalation rates. In addition, competing alternatives must be analyzed over the same life. For alternatives with different estimated lifetimes, appropriate replacements at end of life, salvage values, and economic values must be considered. Twenty-five years is used as the common project life for this analysis with implementation occurring in 1995. The life-cycle cost of an alternative is calculated by summing the present value of all costs (implementation, energy, and O&M). The net savings of an alternative is the difference between the life-cycle cost of the alternative and that of the existing system or base case. In this analysis the base case is Scenario 1.

The results of the life-cycle cost analysis for the 19 alternative scenarios are shown in Table 4.11 and are expressed in 1995 dollars (the implementation year). Because the emissions credit estimate is volatile, life-cycle costs and net savings are provided with and without the credit. Scenario 17 has the best life-cycle cost (least total cost), therefore the highest net savings. The next best alternative is Scenario 19. The only difference between these two scenarios is the backup boiler included in Scenario 19. The inclusion of a fast response backup boiler may be a technical requirement if the engines are not capable of providing backup thermal energy within the 15-minute requirement of the NCTS facility (noted earlier).

Table 4.10. Summary of Implementation Costs

Scenario	Implementation Cost (1993 $)	Replacement Year[a]	Replacement Cost (1993 $)	Economic Value at End of LCC Period (%)
1	0	2015	1,950,000	81
2	0	n/a	n/a	0
3	0	n/a	n/a	0
4	54,525	2005 & 2019	1,950,000	89
5	90,475	2017	1,950,000	87
6	90,475	n/a	n/a	0
7	1,830,000	2009	1,830,000	18
8	1,865,950	n/a	n/a	0
9	1,865,950	n/a	n/a	0
10	5,554,000	2016	3,080,000	78
11	5,589,950	n/a	n/a	17
12	5,589,950	n/a	n/a	17
13	100,475	n/a	n/a	0
14	259,250	n/a	n/a	0
15	2,024,425	n/a	n/a	0
16	100,475	n/a	n/a	0
17	100,475	n/a	n/a	0
18	259,250	n/a	n/a	0
19	259,250	n/a	n/a	0

(a) Assumes implementation by end of 1995.

Table 4.11. Summary of Life-Cycle Cost Analysis in 1995 Dollars

Scenario	Life-Cycle Cost w/Emission Credit ($)	Life-Cycle Cost w/o Emission Credit ($)	Net Savings w/Emission Credit ($)	Net Savings w/o Emission Credit ($)
1	12,522,000	12,528,000	base case	base case
2	9,286,000	9,509,000	3,236,000	3,019,000
3	8,322,000	8,709,000	4,200,000	3,819,000
4	14,988,000	15,012,000	(2,466,000)	(2,474,000)
5	10,073,000	10,318,000	2,449,000	2,210,000
6	4,319,000	4,709,000	8,203,000	7,819,000
7	13,897,000	13,910,000	(1,375,000)	(1,382,000)
8	9,222,000	9,467,000	3,300,000	3,061,000
9	5,417,000	5,807,000	7,105,000	6,721,000
10	28,923,000	28,936,000	(16,401,000)	(16,408,000)
11	16,099,000	16,344,000	(3,577,000)	(3,816,000)
12	9,233,000	9,621,000	3,289,000	2,907,000
13	898,000	1,342,000	11,624,000	11,186,000
14	1,069,000	1,513,000	11,453,000	11,015,000
15	2,969,000	3,413,000	9,553,000	9,115,000
16	(1,430,000)	(989,000)	13,952,000	13,517,000
17	(2,560,000)	(2,118,000)	15,082,000	14,646,000
18	(1,259,000)	(818,000)	13,781,000	13,346,000
19	(2,389,000)	(1,947,000)	14,911,000	14,475,000

5.0 References

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Appendix A

Public Works Center Meter Utility Reports for 1992

Date of Report
02-Aug-92

Prepared by: PWC San Diego
Utilities Dept
Code 611

METERED UTILITY REPORT

Base	Bldg Number	Util Type	Meter Number	Sort Code	PWC Job Order #	Met U/M	Total Mult	Brief Location Description		RT
NCOGEN	1482	E	1035871	76386	1548002	KWH	600.	ON GENERATOR	SWITCHBOARD NEXTTO GENERATOR RM	02

Comments:

Meter Feeds: TOT GEN OUTPUT (SDG&E MTR)

CONSUMPTION HISTORY

				Monthly				Daily			
Read Date	# of Days in Cycle	Meter Read	VERified/ ESTimated Reading?	Monthly Consumption	Monthly Cost	Change Frm Previous Month	Change Frm Same Month Last Year	Avg Daily Consumption	Avg Daily Cost	Change Frm Previous Month	Change Frm Same Month Last Year
07-Aug-90	28	50019		690600	$44,889	-24 %	165 %	23814	$1,548	-16 %	165 %
07-Sep-90	31	50578		335400	$21,801	-51 %	2562 %	10819	$703	-55 %	2390 %
09-Oct-90	32	50588		6000	$336	-98 %	0 %	188	$11	-98 %	-9 %
05-Nov-90	27	50589		600	$34	-90 %	-100 %	22	$1	-88 %	-100 %
05-Dec-90	30	50772		109800	$6,149	**** %	-92 %	3660	$205	**** %	-91 %
08-Jan-91	34	50772		0	$0	-100 %	-100 %	0	$0	-100 %	-100 %
06-Feb-91	29	50772		0	$0	0 %	-100 %	0	$0	0 %	-100 %
08-Mar-91	30	51513		444600	$24,898	INFNT%	-27 %	14820	$830	INFNT%	-25 %
08-Apr-91	31	52507		596400	$33,398	34 %	6527 %	19239	$1,077	30 %	6527 %
08-May-91	30	53618		666600	$37,330	12 %	405 %	22220	$1,244	15 %	388 %
05-Jun-91	28	54244		378600	$21,094	-44 %	-37 %	13414	$751	-40 %	-33 %
10-Jul-91	35	55978		1040400	$58,262	177 %	15 %	29726	$1,665	122 %	5 %
08-Aug-91	29	56843		519000	$29,064	-50 %	-25 %	17897	$1,002	-40 %	-25 %
12-Sep-91	35	58199		813600	$69,970	57 %	143 %	23246	$1,999	30 %	115 %
10-Oct-91	28	59497		778800	$66,977	-4 %	**** %	27814	$2,392	20 %	**** %
07-Nov-91	28	60100		361800	$31,118	-54 %	**** %	12921	$1,111	-54 %	**** %
05-Dec-91	28	60100		0	$0	-100 %	-100 %	0	$0	-100 %	-100 %
09-Jan-92	35	60736		381600	$32,818	INFNT%	INFNT %	10903	$938	INFNT%	INFNT %
06-Feb-92	28	61966		738000	$63,468	93 %	INFNT %	26357	$2,267	142 %	INFNT %
12-Mar-92	35	63545		947400	$81,476	28 %	113 %	27069	$2,328	3 %	83 %
09-Apr-92	28	64811		759600	$65,326	-20 %	27 %	27129	$2,333	0 %	41 %
07-May-92	28	66090		767400	$65,996	1 %	15 %	27407	$2,357	1 %	23 %
04-Jun-92	28	67320		738000	$63,468	-4 %	96 %	26357	$2,267	-4 %	96 %
09-Jul-92	35	68869		929400	$79,928	26 %	-11 %	26554	$2,284	1 %	-11 %

Date of Report
02-Aug-92

Prepared by: PWC San Diego
Utilities Dept
Code 611

METERED UTILITY REPORT

Base	Bldg Number	Util Type	Meter Number	Sort Code	PWC Job Order #	Met U/M	Total Mult	Brief Location Description	RT
NCOGEN	1482	E	630851	76381	5118500	KWH	1.	SEE GUARD MAIN ENTRY FOR ESCORTIN MAIN SW ROOM BY ROLLDR #186B	02

Comments:

Meter Feeds: POWERHOUSE LOAD (SDG&E MTR)

CONSUMPTION HISTORY

				Monthly				Daily			
Read Date	# of Days in Cycle	Meter Read	VERified/ ESTimated Reading?	Monthly Consumption	Monthly Cost	Change Frm Previous Month	Change Frm Same Month Last Year	Avg Daily Consumption	Avg Daily Cost	Change Frm Previous Month	Change Frm Same Month Last Year
07-Aug-90	29	29271		16040	$1,043	16 %	204 %	553	$36	28 %	204 %
07-Sep-90	31	38015		8744	$568	-45 %	1621 %	282	$18	-49 %	1510 %
09-Oct-90	32	38364		349	$20	-96 %	22 %	11	$1	-96 %	10 %
05-Nov-90	27	38477		113	$6	-68 %	-99 %	4	$0	-62 %	-99 %
05-Dec-90	30	40388		1911	$107	1591 %	-91 %	64	$4	1422 %	-90 %
08-Jan-91	34	42263		1875	$105	-2 %	-90 %	55	$3	-13 %	-91 %
06-Feb-91	29	44822		2559	$143	36 %	-84 %	88	$5	60 %	-84 %
08-Mar-91	30	52123		7301	$409	185 %	-18 %	243	$14	176 %	-15 %
08-Apr-91	31	58969		6846	$383	-6 %	1919 %	221	$12	-9 %	1920 %
08-May-91	30	65856		6887	$386	1 %	189 %	230	$13	4 %	180 %
05-Jun-91	28	69477		3621	$203	-47 %	-56 %	129	$7	-44 %	-62 %
10-Jul-91	35	84328		14851	$832	310 %	8 %	424	$24	228 %	-2 %
08-Aug-91	29	91943		7615	$426	-49 %	-53 %	263	$15	-38 %	-53 %
12-Sep-91	35	3513		11570	$995	52 %	32 %	331	$28	26 %	17 %
10-Oct-91	28	16348		11835	$1,018	2 %	9291 %	423	$36	28 %	9776 %
07-Nov-91	28	20851		5503	$473	-54 %	4770 %	197	$17	-54 %	4896 %
05-Dec-91	28	21061		210	$18	-96 %	-89 %	8	$1	-96 %	-88 %
09-Jan-92	35	24891		3830	$329	1724 %	104 %	109	$9	1359 %	98 %
06-Feb-92	28	33379		8488	$730	122 %	232 %	303	$26	177 %	244 %
12-Mar-92	35	43377		9998	$860	18 %	97 %	286	$25	-6 %	17 %
09-Apr-92	28	51785		8408	$723	-16 %	23 %	300	$26	5 %	36 %
07-May-92	28	66343		14558	$1,252	73 %	111 %	520	$45	73 %	126 %
04-Jun-92	28	74614		8271	$711	-43 %	128 %	295	$25	-43 %	128 %
09-Jul-92	35	84676		10062	$865	22 %	-32 %	287	$25	-3 %	-32 %

Date of Report
02-Aug-92

Prepared by: PWC San Diego
Utilities Dept
Code 611

METERED UTILITY REPORT

Base	Bldg Number	Util Type	Meter Number	Sort Code	PWC Job Order #	Met U/M	Total Mult	Brief Location Description	RT
NASNI	1482	G	T12221-0	30000	5195502	CF	100.	ENGINE RM IN LFTCRNR AS YOU ENTRTHE DOOR FACING THE ENGINES	02

Comments:

Meter Feeds:BLDG 1482 COGENGAS '

CONSUMPTION HISTORY

Read Date	# of Days In Cycle	Meter Read	VERIfied/ ESTImated Reading?	Monthly Consumption	Monthly Cost	Change Frm Previous Month	Change Frm Same Month Last Year	Avg Daily Consumption	Avg Daily Cost	Change Frm Previous Month	Change Frm Same Month Last Year
				Monthly				Daily			
07-Aug-90	29	42060	EST	5368000	$46,312	-42 %		185103	$1,666	-36 %	
07-Sep-90	31	48774	EST	6714000	$60,426	25 %		216581	$1,949	17 %	
09-Oct-90	32	55451	EST	6677000	$60,093	-1 %		208656	$1,878	-4 %	
25-Oct-90	16	2429		0	$0	-100 %		0	$0	-100 %	
05-Dec-90	41	12569		1014000	$9,126	INFNT%		24732	$223	INFNT%	
08-Jan-91	34	12574		500	$5	-100 %		15	$0	-100 %	
06-Feb-91	29	12575		100	$1	-80 %		3	$0	-77 %	
08-Mar-91	30	55955		4338000	$39,042	**** %	-31 %	144600	$1,301	**** %	-28 %
08-Apr-91	31	113608		5765300	$51,888	33 %	-8 %	185977	$1,674	29 %	-8 %
08-May-91	30	179285		6587700	$59,109	14 %	1137 %	218923	$1,970	18 %	1096 %
06-Jun-91	28	218888		3760300	$33,843	-43 %	-36 %	134296	$1,209	-39 %	-31 %
10-Jul-91	35	320223		10333500	$93,002	175 %	12 %	295243	$2,657	120 %	3 %
08-Aug-91	29	372498		5227500	$47,048	-49 %	-3 %	180259	$1,622	-39 %	-3 %
12-Sep-91	35	433203		6070500	$60,705	16 %	-10 %	173443	$1,734	-4 %	-20 %
10-Oct-91	28	465619		3241600	$32,416	-47 %	-51 %	115771	$1,158	-33 %	-45 %
07-Nov-91	28	480975		1535600	$15,356	-53 %	INFNT %	54843	$548	-53 %	INFNT %
05-Dec-91	28	480976		100	$1	-100 %	-100 %	4	$0	-100 %	-100 %
09-Jan-92	35	518997		3802100	$38,021	**** %	**** %	108631	$1,086	**** %	**** %
08-Feb-92	28	594764		7578700	$75,787	99 %	**** %	270896	$2,706	149 %	**** %
12-Mar-92	35	691913		9714900	$97,149	28 %	124 %	277569	$2,776	3 %	92 %
09-Apr-92	28	768341		7642800	$76,428	-21 %	33 %	272957	$2,730	-2 %	47 %
07-May-92	28	847301		7896000	$78,960	3 %	20 %	282000	$2,820	3 %	29 %
04-Jun-92	28	922517		7521600	$75,216	-5 %	100 %	268629	$2,686	-5 %	100 %
09-Jul-92	35	1019939		9742200	$97,422	30 %	-6 %	278349	$2,783	4 %	-6 %
		1080404		6916500							

6- Dec-92 Pressure Transmitter found shut off and corrected
14- Aug-92 New Gas Meter Installed

Date of Report
08-Jan-93

Prepared by: PWC San Diego
Utilities Dept
Code 611

METERED UTILITY REPORT

Base	Bldg Number	Util Type	Meter Number	Sort Code	PWC Job Order #	Met U/M	Total Mult	Brief Location Description	RT
NASNI	1482	ST	2203009-L008	13800	5198531	MBT	1.	IN CHILLER ROOM ON WALL ENGINE ROOM SIDE	08

Comments:

Meter Feeds: 1482(COGEN)

CONSUMPTION HISTORY

Read Date	# of Days In Cycle	Meter Read	VERified/ ESTimated Reading?	Monthly Consumption	Monthly Cost	Change Frm Previous Month	Change Frm Same Month Last Year	Avg Daily Consumption	Avg Daily Cost	Change Frm Previous Month	Change Frm Same Month Last Year
				Monthly				Daily			
08-Jan-91	34	2187229		6317	$56,853	45 %		186	$1,672	28 %	
06-Feb-91	29	2603283		4964	$44,676	-21 %		171	$1,541	-8 %	
08-Mar-91	30	2722573		1423	$12,807	-71 %	-90 %	47	$427	-72 %	-88 %
08-Apr-91	31	2741546		226	$2,034	-84 %	-96 %	7	$66	-85 %	-96 %
08-May-91	30	2864012		1461	$13,149	546 %	-69 %	49	$438	568 %	-70 %
05-Jun-91	28	3073085		2494	$22,000	71 %	-6 %	89	$1	88 %	0 %
10-Jul-91	35	3130038		679	$6,000	-73 %	-63 %	19	$0	-78 %	-66 %
08-Aug-91	29	3372261		2890	$26,000	326 %	15 %	100	$1	414 %	15 %
12-Sep-91	35	3542807		2035	$28,000	-30 %	-67 %	58	$1	-42 %	-71 %
10-Oct-91	28	3638397		1140	$16,000	-44 %	-84 %	41	$1	-30 %	-81 %
07-Nov-91	28	3726547		1052	$15,000	-8 %	-79 %	38	$1	-8 %	-80 %
05-Dec-91	28	3838410		1335	$19,000	27 %	-69 %	48	$1	27 %	-67 %
09-Jan-92	35	3960290		1454	$20,356	9 %	-77 %	42	$582	-13 %	-78 %
06-Feb-92	28	4056339		1146	$16,044	-21 %	-77 %	41	$573	-1 %	-76 %
12-Mar-92	35	4180972		1487	$20,818	30 %	4 %	42	$595	4 %	+10 %
09-Apr-92	28	4286367		1257	$17,598	-15 %	456 %	45	$629	6 %	516 %
07-May-92	28	4416120		1548	$21,672	23 %	6 %	55	$774	23 %	14 %
* 04-Jun-92	28	4551129	EST	1611	$22,554	4 %	-35 %	58	$806	4 %	-35 %
09-Jul-92	35	4651120		1193000	16,702,000	**** %	**** %	34086	477,200	**** %	**** %
06-Aug-92	28	317507		986	$13,804	-100 %	-66 %	35	$493	-100 %	-65 %
10-Sep-92	35	322327		575	$8,625	-42 %	-72 %	16	$246	-53 %	-72 %
07-Oct-92	27	496		1125	$16,875	96 %	-1 %	42	$625	154 %	2 %
04-Nov-92	28	858		362	$5,430	-68 %	-66 %	13	$194	-69 %	-66 %
09-Dec-92	35	893		35	$525	-90 %	-97 %	1	$15	-92 %	-98 %
06-JAN 93	28	936		43							

* FEDL FOR MAY - USED (1548 + 1611 + 1193) ÷ 3 = 1450.7
(STEAM)

Appendix B

Natural-Gas Unit Cost Calculations for 1992

Table B.1. Unit Cost Calculations for Natural Gas

1992 Month	Billing Season	Cogen Rate Procurement ($/therm)	Cogen Rate Transmission ($/therm)	Non-Cogen Rate Procurement ($/therm)	Non-Cogen Rate Transmission ($/therm)
Jan	W	$0.215230	$0.120430	$0.215230	$0.177210
Feb	W	$0.163980	$0.120430	$0.163980	$0.177210
Mar	W	$0.163980	$0.119575	$0.163980	$0.176012
Apr	S	$0.163980	$0.095660	$0.163980	$0.142470
May	S	$0.174540	$0.096787	$0.174540	$0.144482
Jun	S	$0.178865	$0.097520	$0.178865	$0.145790
Jul	S	$0.169575	$0.097520	$0.169575	$0.145790
Aug	S	$0.215760	$0.097520	$0.215760	$0.145790
Sep	S	$0.230600	$0.097520	$0.230600	$0.145790
Oct	S	$0.272918	$0.097520	$0.272918	$0.145790
Nov	S	$0.238458	$0.099173	$0.238458	$0.148116
Dec	W	$0.204987	$0.124140	$0.204987	$0.183245
Average:					
Winter		$0.18704	$0.12114	$0.18704	$0.17842
Summer		$0.20559	$0.09740	$0.20559	$0.14550

	Summer	Winter	
Cogen Rate:			
Procurement	$0.20559	$0.18704	
Transmission	$0.09740	$0.12114	
Reg. Fee	$0.00076	$0.00076	
Total	$0.30375	$0.30895	/therm
Non-Cogen Rate:			
Procurement	$0.20559	$0.18704	
Transmission	$0.14550	$0.17842	
Reg. Fee	$0.00076	$0.00076	
Total	$0.35185	$0.36622	/therm

Appendix C

Public Works Center Federal Energy Regulatory Commission Calculations for 1992

COGENERATION DATA SUMMARY

Data for year 1992 — NAVAL COMP. TELECOM. CNTR. (Facility name or No.) — 28 JAN 1993 (date)

Month	Natural Gas & Oil Energy Input	Useful Power Output	Useful Thermal Energy Output	Total Energy Output
Jan	9233 LHV	2585	3844	6429
Feb	10141	2922	1363	4285
Mar	8976	2650	2437	5087
Apr	8896	2677	1791	4468
May	9637	2934	2243	5177
Jun	8585	2589	2536	5125
Jul	9848	3052	2426	5478
Aug	8091	2518	2826	5344
Sep	9067	2783	2112	4895
Oct	9464	2933	2770	5703
Nov	9377	2797	2680	5477
Dec	11069	3035	2683	5718
Totals	112384 (A)	33475 (B)	29711 (C)	63186 (D) Million BTU's

The operating and efficiency standards in equation form are:

1. operating standard

$$\frac{C}{D} \times 100\% \geq 5\%$$

2. efficiency standard

$$\left(\frac{B + \frac{C}{2}}{A}\right) \times 100\% \geq 42.5$$

My operating standard result is 47.0%.

My efficiency standard result is 43.0%.

signature — for — PWC San Diego, CA (entity)

Head, Utilities Department (title)

Relationship to the cogeneration facility owner Head, Utilities Department

Appendix D

Marginal Energy Cost Calculations - Cogen Gas Rate

Marginal Energy Cost Analysis - Cogen Gas Rate

		Summer	Winter				
Electric Rate							
Energy							
	On-Peak	$0.06886	$0.06171	/kWh			
	Semi-Peak	$0.04533	$0.03864	/kWh			
	Off-Peak	$0.03369	$0.03186	/kWh			
Demand							
	System Peak	$13.39	$2.17	/kW			
	True Peak	$1.24	$1.24	/kW			
Natural Gas Rate							
	Cogen	$0.30375	$0.30895	/therm	Based on:	0.107	therm/kwh
	Non-cogen	$0.35185	$0.36622	/therm		all additional gas	
Steam Rate							
	Avoided Cost	$1.961	$1.591	/Mlbs @100 psig, or			
	Avoided Cost	$0.222	$0.180	/therm			
Engine Rating							
	Rated Load	100%	650	kW			
	Derated Load	92.31%	600	kW			

Engine Specifications	Load	100%	75%	50%	25%	Units
Fuel Input (HHV)		7,807,000	6,193,000	4,623,500	3,091,500	Btu/h
Heat Rate		12,011	12,691	14,226	18,966	Btu/kWh
Electrical		650	488	325	163	kW
- Electrical		2,217,800	1,665,056	1,108,900	556,156	Btu/h
- Percent of Fuel Input		28.41%	26.89%	23.98%	17.99%	
Thermal-exhaust		2,672,000	1,990,000	1,378,500	839,400	Btu/h
- Percent of Fuel Input		34.23%	32.13%	29.82%	27.15%	
- Recoverable		1,429,700	1,017,000	662,000	362,000	Btu/h
–Percent of total exhaust		53.51%	51.11%	48.02%	43.13%	
- Non-Recov.		1,242,300	973,000	716,500	477,400	Btu/h
Thermal-jacket water		2,050,740	1,626,775	1,214,499	812,074	Btu/h
- Percent of Fuel Input		26.27%	26.27%	26.27%	26.27%	
- Recoverable		2,009,725	1,594,240	1,190,209	795,833	Btu/h
–Percent of total jacket		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		41,015	32,536	24,290	16,241	Btu/h
Thermal-lube oil		232,020	184,053	137,408	91,878	Btu/h
- Percent of Fuel Input		2.97%	2.97%	2.97%	2.97%	
- Recoverable		227,380	180,372	134,660	90,040	Btu/h
–Percent of total lube oil		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		4,640	3,681	2,748	1,838	Btu/h
Thermal-intercooler		153,540	121,798	90,930	60,800	Btu/h
- Percent of Fuel Input		1.97%	1.97%	1.97%	1.97%	
- Recoverable		150,469	119,362	89,112	59,584	Btu/h
–Percent of total intercir		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		3,071	2,436	1,819	1,216	Btu/h
Thermal-radiation		317,340	317,340	317,340	317,340	Btu/h
- Percent of Fuel Input		4.06%	5.12%	6.86%	10.26%	
Thermal-unaccounted (a)		163,560	287,979	375,922	413,852	Btu/h
- Percent of Fuel Input		2.10%	4.65%	8.13%	13.39%	
Total Thermal Recoverable		3,817,274	2,910,973	2,075,981	1,307,457	Btu/h
- Percent of Fuel Input		48.90%	47.00%	44.90%	42.29%	

(a) Unaccounted thermal energy most likely in the jacket water and lube oil heat system.
Shaded area not documented in equipment specifications, assumed values.

Efficiency Analysis

Efficiency (based on HHV of fuel)	Load	100%	75%	50%	25%
Electrical		28.41%	26.89%	23.98%	17.99%
Thermal Recoverable		48.90%	47.00%	44.90%	42.29%
Total Cogen Efficiency		77.30%	73.89%	68.88%	60.28%

Efficiency (based on LHV of fuel)	Load	100%	75%	50%	25%
Net Electrical		30.31%	28.62%	25.40%	18.74%
Thermal Recoverable		54.33%	52.23%	49.89%	46.99%
Total Cogen Efficiency		84.64%	80.85%	75.29%	65.73%

FERC Efficiency (a)					
Thermal energy usable	100%	57.48%	54.74%	50.34%	42.23%
(percent of recoverable)	90%	54.76%	52.13%	47.85%	39.89%
	80%	52.05%	49.51%	45.35%	37.54%
	75%	50.69%	48.21%	44.11%	36.36%
	70%	49.33%	46.90%	42.86%	35.19%
	60%	46.61%	44.29%	40.37%	32.84%
	50%	43.90%	41.68%	37.87%	30.49%
	40%	41.18%	39.07%	35.38%	28.14%

(a) Shaded area does not meet SDG&E efficiency requirements as a Qualified Facility (QF).
FERC efficiency = net electrical efficiency + 1/2 useful thermal efficiency
FERC calculations based on fuel lower heating value (LHV).

Value of Cogenerated Energy
Engine Full Load
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
92.31%	7,310,385	Btu/h - total	($22.63)	($22.63)	($22.63)	($23.10)	($23.10)	($23.10)
	6,420,000	Btu/h - cogen rate						
Electrical Output								
92.31%	600	kW	$41.32	$27.20	$20.21	$37.03	$23.18	$19.12
Heat Recoverable and Useable								
100%	3,523,638	Btu/h	$7.84	$7.84	$7.84	$6.36	$6.36	$6.36
90%	3,171,274	Btu/h	$7.05	$7.05	$7.05	$5.72	$5.72	$5.72
80%	2,818,910	Btu/h	$6.27	$6.27	$6.27	$5.09	$5.09	$5.09
75%	2,642,728	Btu/h	$5.88	$5.88	$5.88	$4.77	$4.77	$4.77
70%	2,466,546	Btu/h	$5.49	$5.49	$5.49	$4.45	$4.45	$4.45
60%	2,114,183	Btu/h	$4.70	$4.70	$4.70	$3.81	$3.81	$3.81
50%	1,761,819	Btu/h	$3.92	$3.92	$3.92	$3.18	$3.18	$3.18
40%	1,409,455	Btu/h	$3.13	$3.13	$3.13	$2.54	$2.54	$2.54
30%	1,057,091	Btu/h	$2.35	$2.35	$2.35	$1.91	$1.91	$1.91
25%	880,909	Btu/h	$1.96	$1.96	$1.96	$1.59	$1.59	$1.59
20%	704,728	Btu/h	$1.57	$1.57	$1.57	$1.27	$1.27	$1.27
10%	352,364	Btu/h	$0.78	$0.78	$0.78	$0.64	$0.64	$0.64
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
	Useable Thermal Energy						
	100%	$26.52	$12.40	$5.42	$20.29	$6.45	$2.38
	90%	$25.73	$11.62	$4.63	$19.65	$5.81	$1.74
	80%	$24.95	$10.83	$3.85	$19.02	$5.17	$1.11
	75%	$24.56	$10.44	$3.46	$18.70	$4.86	$0.79
	70%	$24.17	$10.05	$3.07	$18.38	$4.54	$0.47
	60%	$23.38	$9.27	$2.28	$17.75	$3.90	($0.16)
	50%	$22.60	$8.48	$1.50	$17.11	$3.27	($0.80)
	40%	$21.82	$7.70	$0.71	$16.47	$2.63	($1.44)
	30%	$21.03	$6.92	($0.07)	$15.84	$2.00	($2.07)
	25%	$20.64	$6.52	($0.46)	$15.52	$1.68	($2.39)
	20%	$20.25	$6.13	($0.85)	$15.20	$1.36	($2.71)
	10%	$19.47	$5.35	($1.64)	$14.57	$0.72	($3.34)
	0%	$18.68	$4.56	($2.42)	$13.93	$0.09	($3.98)

Value of Cogenerated Energy
Thermal Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
92%	7,310,534	Btu/h	($22.63)	($22.63)	($22.63)	($23.09)	($23.09)	($23.09)
90%	7,161,400	Btu/h	($22.19)	($22.19)	($22.19)	($22.64)	($22.64)	($22.64)
80%	6,515,800	Btu/h	($20.25)	($20.25)	($20.25)	($20.67)	($20.67)	($20.67)
75%	6,193,000	Btu/h	($19.28)	($19.28)	($19.28)	($19.69)	($19.69)	($19.69)
70%	5,879,100	Btu/h	($18.34)	($18.34)	($18.34)	($18.74)	($18.74)	($18.74)
60%	5,251,300	Btu/h	($16.47)	($16.47)	($16.47)	($16.84)	($16.84)	($16.84)
50%	4,623,500	Btu/h	($14.60)	($14.60)	($14.60)	($14.94)	($14.94)	($14.94)
40%	4,010,700	Btu/h	($12.77)	($12.77)	($12.77)	($13.09)	($13.09)	($13.09)
30%	3,397,900	Btu/h	($10.95)	($10.95)	($10.95)	($11.25)	($11.25)	($11.25)
25%	3,091,500	Btu/h	($10.04)	($10.04)	($10.04)	($10.32)	($10.32)	($10.32)
Heat Recoverable and Useable								
92%	3,538,496	Btu/h	$7.87	$7.87	$7.87	$6.38	$6.38	$6.38
90%	3,454,754	Btu/h	$7.68	$7.68	$7.68	$6.23	$6.23	$6.23
80%	3,092,233	Btu/h	$6.88	$6.88	$6.88	$5.58	$5.58	$5.58
75%	2,910,973	Btu/h	$6.47	$6.47	$6.47	$5.25	$5.25	$5.25
70%	2,743,974	Btu/h	$6.10	$6.10	$6.10	$4.95	$4.95	$4.95
60%	2,409,978	Btu/h	$5.36	$5.36	$5.36	$4.35	$4.35	$4.35
50%	2,075,981	Btu/h	$4.62	$4.62	$4.62	$3.75	$3.75	$3.75
40%	1,768,571	Btu/h	$3.93	$3.93	$3.93	$3.19	$3.19	$3.19
30%	1,461,162	Btu/h	$3.25	$3.25	$3.25	$2.64	$2.64	$2.64
25%	1,307,457	Btu/h	$2.91	$2.91	$2.91	$2.36	$2.36	$2.36
Electrical Output								
92%	600	kW	$41.33	$27.21	$20.22	$37.04	$23.19	$19.12
90%	585	kW	$40.30	$26.53	$19.72	$36.11	$22.61	$18.64
80%	520	kW	$35.83	$23.59	$17.53	$32.11	$20.11	$16.58
75%	488	kW	$33.60	$22.12	$16.44	$30.11	$18.86	$15.55
70%	455	kW	$31.36	$20.64	$15.34	$28.10	$17.60	$14.51
60%	390	kW	$26.87	$17.69	$13.15	$24.08	$15.08	$12.43
50%	325	kW	$22.38	$14.73	$10.95	$20.06	$12.56	$10.35
40%	260	kW	$17.92	$11.79	$8.77	$16.06	$10.05	$8.29
30%	195	kW	$13.46	$8.86	$6.58	$12.06	$7.55	$6.23
25%	163	kW	$11.22	$7.39	$5.49	$10.06	$6.30	$5.19
Net Marginal Value of Energy								
	92%		$26.56	$12.44	$5.46	$20.33	$6.48	$2.41
	90%		$25.79	$12.02	$5.21	$19.71	$6.21	$2.24
	80%		$22.46	$10.22	$4.16	$17.02	$5.01	$1.49
	75%		$20.80	$9.32	$3.64	$15.68	$4.42	$1.11
	70%		$19.12	$8.40	$3.10	$14.31	$3.81	$0.72
	60%		$15.76	$6.58	$2.04	$11.59	$2.59	($0.06)
	50%		$12.40	$4.75	$0.97	$8.86	$1.36	($0.84)
	40%		$9.08	$2.96	($0.07)	$6.15	$0.15	($1.61)
	30%		$5.75	$1.16	($1.12)	$3.45	($1.06)	($2.38)
	25%		$4.09	$0.26	($1.64)	$2.09	($1.67)	($2.77)

Value of Cogenerated Energy
Electrical Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
75.00%	6,193,000	Btu/h - total	($19.28)	($19.28)	($19.28)	($19.69)	($19.69)	($19.69)
	5,221,600	Btu/h - cogen rate						
Electrical Output								
75.00%	488	kW	$33.60	$22.12	$16.44	$30.11	$18.86	$15.55
Heat Recoverable and Useable								
100%	2,910,973	Btu/h	$6.47	$6.47	$6.47	$5.25	$5.25	$5.25
90%	2,619,876	Btu/h	$5.83	$5.83	$5.83	$4.73	$4.73	$4.73
80%	2,328,778	Btu/h	$5.18	$5.18	$5.18	$4.20	$4.20	$4.20
75%	2,183,230	Btu/h	$4.86	$4.86	$4.86	$3.94	$3.94	$3.94
70%	2,037,681	Btu/h	$4.53	$4.53	$4.53	$3.68	$3.68	$3.68
60%	1,746,584	Btu/h	$3.88	$3.88	$3.88	$3.15	$3.15	$3.15
50%	1,455,486	Btu/h	$3.24	$3.24	$3.24	$2.63	$2.53	$2.63
40%	1,164,389	Btu/h	$2.59	$2.59	$2.59	$2.10	$2.10	$2.10
30%	873,292	Btu/h	$1.94	$1.94	$1.94	$1.58	$1.58	$1.58
25%	727,743	Btu/h	$1.62	$1.62	$1.62	$1.31	$1.31	$1.31
20%	582,195	Btu/h	$1.29	$1.29	$1.29	$1.05	$1.05	$1.05
10%	291,097	Btu/h	$0.65	$0.65	$0.65	$0.53	$0.53	$0.53
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy

Useable Thermal Energy	Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
100%	$20.80	$9.32	$3.64	$15.68	$4.42	$1.11
90%	$20.15	$8.67	$2.99	$15.15	$3.89	$0.59
80%	$19.50	$8.02	$2.34	$14.63	$3.37	$0.06
75%	$19.18	$7.70	$2.02	$14.36	$3.11	($0.20)
70%	$18.86	$7.37	$1.69	$14.10	$2.84	($0.47)
60%	$18.21	$6.73	$1.05	$13.58	$2.32	($0.99)
50%	$17.56	$6.08	$0.40	$13.05	$1.79	($1.52)
40%	$16.91	$5.43	($0.25)	$12.53	$1.27	($2.04)
30%	$16.27	$4.78	($0.90)	$12.00	$0.74	($2.57)
25%	$15.94	$4.46	($1.22)	$11.74	$0.48	($2.83)
20%	$15.62	$4.14	($1.54)	$11.48	$0.22	($3.09)
10%	$14.97	$3.49	($2.19)	$10.95	($0.31)	($3.62)
0%	$14.33	$2.84	($2.84)	$10.42	($0.83)	($4.14)

Value of Cogenerated Energy
Electrical Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
50.00%	4,623,500	Btu/h - total	($14.60)	($14.60)	($14.60)	($14.94)	($14.94)	($14.94)
	3,477,500	Btu/h - cogen rate						
Electrical Output								
50.00%	325	kW	$22.38	$14.73	$10.95	$20.06	$12.56	$10.35
Heat Recoverable and Useable								
100%	2,075,981	Btu/h	$4.62	$4.62	$4.62	$3.75	$3.75	$3.75
90%	1,868,383	Btu/h	$4.15	$4.15	$4.15	$3.37	$3.37	$3.37
80%	1,660,785	Btu/h	$3.69	$3.69	$3.69	$3.00	$3.00	$3.00
75%	1,556,986	Btu/h	$3.46	$3.46	$3.46	$2.81	$2.81	$2.81
70%	1,453,187	Btu/h	$3.23	$3.23	$3.23	$2.62	$2.62	$2.62
60%	1,245,589	Btu/h	$2.77	$2.77	$2.77	$2.25	$2.25	$2.25
50%	1,037,990	Btu/h	$2.31	$2.31	$2.31	$1.87	$1.87	$1.87
40%	830,392	Btu/h	$1.85	$1.85	$1.85	$1.50	$1.50	$1.50
30%	622,794	Btu/h	$1.38	$1.38	$1.38	$1.12	$1.12	$1.12
25%	518,995	Btu/h	$1.15	$1.15	$1.15	$0.94	$0.94	$0.94
20%	415,196	Btu/h	$0.92	$0.92	$0.92	$0.75	$0.75	$0.75
10%	207,598	Btu/h	$0.46	$0.46	$0.46	$0.37	$0.37	$0.37
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy

Useable Thermal Energy	Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
100%	$12.40	$4.75	$0.97	$8.86	$1.36	($0.84)
90%	$11.94	$4.29	$0.51	$8.49	$0.99	($1.21)
80%	$11.48	$3.83	$0.05	$8.11	$0.61	($1.59)
75%	$11.25	$3.60	($0.18)	$7.92	$0.43	($1.78)
70%	$11.02	$3.37	($0.41)	$7.74	$0.24	($1.96)
60%	$10.55	$2.91	($0.88)	$7.36	($0.14)	($2.34)
50%	$10.09	$2.45	($1.34)	$6.99	($0.51)	($2.71)
40%	$9.63	$1.98	($1.80)	$6.61	($0.88)	($3.09)
30%	$9.17	$1.52	($2.26)	$6.24	($1.26)	($3.46)
25%	$8.94	$1.29	($2.49)	$6.05	($1.45)	($3.65)
20%	$8.71	$1.06	($2.72)	$5.86	($1.63)	($3.84)
10%	$8.25	$0.60	($3.18)	$5.49	($2.01)	($4.21)
0%	$7.78	$0.14	($3.65)	$5.12	($2.38)	($4.59)

Appendix E

Marginal Energy Cost Calculations - Non-Cogen Gas Rate

Marginal Energy Cost Analysis - Non-Cogen Gas Rate

		Summer	Winter	
Electric Rate				
Energy				
	On-Peak	$0.06886	$0.06171	/kWh
	Semi-Peak	$0.04533	$0.03864	/kWh
	Off-Peak	$0.03369	$0.03186	/kWh
Demand				
	System Peak	$13.39	$2.17	/kW
	True Peak	$1.24	$1.24	/kW
Natural Gas Rate				
	Non-cogen	$0.35185	$0.36622	/therm
Steam Rate				
	Avoided Cost	$1.961	$1.591	/Mlbs @100 psig, or
	Avoided Cost	$0.222	$0.180	/therm
Engine Rating				
	Rated Load	100%	650	kW
	Derated Load	92.31%	600	kW

Engine Specifications	Load	100%	75%	50%	25%	Units
Fuel Input (HHV)		7,807,000	6,193,000	4,623,500	3,091,500	Btu/h
Heat Rate		12,011	12,691	14,226	18,966	Btu/kWh
Electrical		650	488	325	163	kW
- Electrical		2,217,800	1,665,056	1,108,900	556,156	Btu/h
- Percent of Fuel Input		28.41%	26.89%	23.98%	17.99%	
Thermal-exhaust		2,672,000	1,990,000	1,378,500	839,400	Btu/h
- Percent of Fuel Input		34.23%	32.13%	29.82%	27.15%	
- Recoverable		1,429,700	1,017,000	662,000	362,000	Btu/h
--Percent of total exhaust		53.51%	51.11%	48.02%	43.13%	
- Non-Recov.		1,242,300	973,000	716,500	477,400	Btu/h
Thermal-jacket water		2,050,740	1,626,775	1,214,499	812,074	Btu/h
- Percent of Fuel Input		26.27%	26.27%	26.27%	26.27%	
- Recoverable		2,009,725	1,594,240	1,190,209	795,833	Btu/h
--Percent of total jacket		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		41,015	32,536	24,290	16,241	Btu/h
Thermal-lube oil		232,020	184,053	137,408	91,878	Btu/h
- Percent of Fuel Input		2.97%	2.97%	2.97%	2.97%	
- Recoverable		227,380	180,372	134,660	90,040	Btu/h
--Percent of total lube oil		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		4,640	3,681	2,748	1,838	Btu/h
Thermal-intercooler		153,540	121,798	90,930	60,800	Btu/h
- Percent of Fuel Input		1.97%	1.97%	1.97%	1.97%	
- Recoverable		150,469	119,362	89,112	59,584	Btu/h
--Percent of total intercir		98.00%	98.00%	98.00%	98.00%	
- Non-Recov.		3,071	2,436	1,819	1,216	Btu/h
Thermal-radiation		317,340	317,340	317,340	317,340	Btu/h
- Percent of Fuel Input		4.06%	5.12%	6.86%	10.26%	
Thermal-unaccounted (a)		163,560	287,979	375,922	413,852	Btu/h
- Percent of Fuel Input		2.10%	4.65%	8.13%	13.39%	
Total Thermal Recoverable		3,817,274	2,910,973	2,075,981	1,307,457	Btu/h
- Percent of Fuel Input		48.90%	47.00%	44.90%	42.29%	

(a) Unaccounted thermal energy most likely in the jacket water and lube oil heat system.
Shaded area not documented in equipment specifications, therefore assumed values.

Efficiency Analysis

Efficiency (based on HHV of fuel)	Load	100%	75%	50%	25%
Electrical		28.41%	26.89%	23.98%	17.99%
Thermal Recoverable		48.90%	47.00%	44.90%	42.29%
Total Cogen Efficiency		77.30%	73.89%	68.88%	60.28%

Efficiency (based on LHV of fuel)	Load	100%	75%	50%	25%
Net Electrical		30.31%	28.62%	25.40%	18.74%
Thermal Recoverable		54.33%	52.23%	49.89%	46.99%
Total Cogen Efficiency		84.64%	80.85%	75.29%	65.73%

FERC Efficiency (a)					
Thermal energy usable	100%	57.48%	54.74%	50.34%	42.23%
(percent of recoverable)	90%	54.76%	52.13%	47.85%	39.58%
	80%	52.05%	49.51%	45.35%	37.54%
	75%	50.69%	48.21%	44.11%	36.35%
	70%	49.33%	46.90%	42.86%	35.19%
	60%	46.61%	44.29%	40.37%	32.84%
	50%	43.90%	41.68%	37.87%	30.49%
	40%	41.18%	39.07%	35.38%	28.14%

(a) Shaded area does not meet SDG&E efficiency requirements as a Qualified Facility (QF).
FERC efficiency = net electrical efficiency + 1/2 useful thermal efficiency
Calculations based on fuel lower heating value (LHV).

Value of Cogenerated Energy
Engine Full Load
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
92.31%	7,310,385	Btu/h	($25.72)	($25.72)	($25.72)	($26.77)	($26.77)	($26.77)
Electrical Output								
92.31%	600	kW	$41.32	$27.20	$20.21	$37.03	$23.18	$19.12
Heat Recoverable and Useable								
100%	3,523,638	Btu/h	$7.84	$7.84	$7.84	$6.36	$6.36	$6.36
90%	3,171,274	Btu/h	$7.05	$7.05	$7.05	$5.72	$5.72	$5.72
80%	2,818,910	Btu/h	$6.27	$6.27	$6.27	$5.09	$5.09	$5.09
75%	2,642,728	Btu/h	$5.88	$5.88	$5.88	$4.77	$4.77	$4.77
70%	2,466,546	Btu/h	$5.49	$5.49	$5.49	$4.45	$4.45	$4.45
60%	2,114,183	Btu/h	$4.70	$4.70	$4.70	$3.81	$3.81	$3.81
50%	1,761,819	Btu/h	$3.92	$3.92	$3.92	$3.18	$3.18	$3.18
40%	1,409,455	Btu/h	$3.13	$3.13	$3.13	$2.54	$2.54	$2.54
30%	1,057,091	Btu/h	$2.35	$2.35	$2.35	$1.91	$1.91	$1.91
25%	880,909	Btu/h	$1.96	$1.96	$1.96	$1.59	$1.59	$1.59
20%	704,728	Btu/h	$1.57	$1.57	$1.57	$1.27	$1.27	$1.27
10%	352,364	Btu/h	$0.78	$0.78	$0.78	$0.64	$0.64	$0.64
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy

Useable Thermal Energy	Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
100%	$23.43	$9.31	$2.33	$16.61	$2.77	($1.30)
90%	$22.65	$8.53	$1.54	$15.98	$2.13	($1.93)
80%	$21.86	$7.75	$0.76	$15.34	$1.50	($2.57)
75%	$21.47	$7.35	$0.37	$15.02	$1.18	($2.89)
70%	$21.08	$6.96	($0.02)	$14.70	$0.86	($3.21)
60%	$20.30	$6.18	($0.81)	$14.07	$0.23	($3.84)
50%	$19.51	$5.39	($1.59)	$13.43	($0.41)	($4.48)
40%	$18.73	$4.61	($2.37)	$12.80	($1.04)	($5.11)
30%	$17.95	$3.83	($3.16)	$12.16	($1.68)	($5.75)
25%	$17.55	$3.44	($3.55)	$11.84	($2.00)	($6.07)
20%	$17.16	$3.04	($3.94)	$11.53	($2.32)	($6.38)
10%	$16.38	$2.26	($4.72)	$10.89	($2.95)	($7.02)
0%	$15.59	$1.48	($5.51)	$10.25	($3.59)	($7.66)

Value of Cogenerated Energy
Thermal Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
92%	7,310,534	Btu/h	($25.72)	($25.72)	($25.72)	($26.77)	($26.77)	($26.77)
90%	7,161,400	Btu/h	($25.20)	($25.20)	($25.20)	($26.23)	($26.23)	($26.23)
80%	6,515,800	Btu/h	($22.93)	($22.93)	($22.93)	($23.86)	($23.86)	($23.86)
75%	6,193,000	Btu/h	($21.79)	($21.79)	($21.79)	($22.68)	($22.68)	($22.68)
70%	5,879,100	Btu/h	($20.69)	($20.69)	($20.69)	($21.53)	($21.53)	($21.53)
60%	5,251,300	Btu/h	($18.48)	($18.48)	($18.48)	($19.23)	($19.23)	($19.23)
50%	4,623,500	Btu/h	($16.27)	($16.27)	($16.27)	($16.93)	($16.93)	($16.93)
40%	4,010,700	Btu/h	($14.11)	($14.11)	($14.11)	($14.69)	($14.69)	($14.69)
30%	3,397,900	Btu/h	($11.96)	($11.96)	($11.96)	($12.44)	($12.44)	($12.44)
25%	3,091,500	Btu/h	($10.88)	($10.88)	($10.88)	($11.32)	($11.32)	($11.32)
Heat Recoverable and Useable								
92%	3,538,496	Btu/h	$7.87	$7.87	$7.87	$6.38	$6.38	$6.38
90%	3,454,754	Btu/h	$7.68	$7.68	$7.68	$6.23	$6.23	$6.23
80%	3,092,233	Btu/h	$6.88	$6.88	$6.88	$5.58	$5.58	$5.58
75%	2,910,973	Btu/h	$6.47	$6.47	$6.47	$5.25	$5.25	$5.25
70%	2,743,974	Btu/h	$6.10	$6.10	$6.10	$4.95	$4.95	$4.95
60%	2,409,978	Btu/h	$5.36	$5.36	$5.36	$4.35	$4.35	$4.35
50%	2,075,981	Btu/h	$4.62	$4.62	$4.62	$3.75	$3.75	$3.75
40%	1,768,571	Btu/h	$3.93	$3.93	$3.93	$3.19	$3.19	$3.19
30%	1,461,162	Btu/h	$3.25	$3.25	$3.25	$2.64	$2.64	$2.64
25%	1,307,457	Btu/h	$2.91	$2.91	$2.91	$2.36	$2.36	$2.36
Electrical Output								
92%	600	kW	$41.33	$27.21	$20.22	$37.04	$23.19	$19.12
90%	585	kW	$40.30	$26.53	$19.72	$36.11	$22.61	$18.64
80%	520	kW	$35.83	$23.59	$17.53	$32.11	$20.11	$16.58
75%	488	kW	$33.60	$22.12	$16.44	$30.11	$18.86	$15.55
70%	455	kW	$31.36	$20.64	$15.34	$28.10	$17.60	$14.51
60%	390	kW	$26.87	$17.69	$13.15	$24.08	$15.08	$12.43
50%	325	kW	$22.38	$14.73	$10.95	$20.06	$12.56	$10.35
40%	260	kW	$17.92	$11.79	$8.77	$16.06	$10.05	$8.29
30%	195	kW	$13.46	$8.86	$6.58	$12.06	$7.55	$6.23
25%	163	kW	$11.22	$7.39	$5.49	$10.06	$6.30	$5.19
Net Marginal Value of Energy								
	92%		$23.47	$9.35	$2.37	$16.65	$2.80	($1.27)
	90%		$22.78	$9.01	$2.20	$16.12	$2.62	($1.35)
	80%		$19.79	$7.54	$1.48	$13.83	$1.83	($1.70)
	75%		$18.29	$6.80	$1.12	$12.69	$1.43	($1.88)
	70%		$16.78	$6.06	$0.76	$11.52	$1.02	($2.07)
	60%		$13.75	$4.57	$0.03	$9.20	$0.19	($2.45)
	50%		$10.73	$3.08	($0.70)	$6.87	($0.63)	($2.83)
	40%		$7.74	$1.62	($1.41)	$4.56	($1.44)	($3.21)
	30%		$4.75	$0.15	($2.12)	$2.25	($2.26)	($3.58)
	25%		$3.25	($0.58)	($2.48)	$1.10	($2.66)	($3.77)

Value of Cogenerated Energy
Electrical Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
75.00%	6,193,000	Btu/h	($21.79)	($21.79)	($21.79)	($22.68)	($22.68)	($22.68)
Electrical Output								
75.00%	488	kW	$33.60	$22.12	$16.44	$30.11	$18.86	$15.55
Heat Recoverable and Useable								
100%	2,910,973	Btu/h	$6.47	$6.47	$6.47	$5.25	$5.25	$5.25
90%	2,619,876	Btu/h	$5.83	$5.83	$5.83	$4.73	$4.73	$4.73
80%	2,328,778	Btu/h	$5.18	$5.18	$5.18	$4.20	$4.20	$4.20
75%	2,183,230	Btu/h	$4.86	$4.86	$4.86	$3.94	$3.94	$3.94
70%	2,037,681	Btu/h	$4.53	$4.53	$4.53	$3.68	$3.68	$3.68
60%	1,746,584	Btu/h	$3.88	$3.88	$3.88	$3.15	$3.15	$3.15
50%	1,455,486	Btu/h	$3.24	$3.24	$3.24	$2.63	$2.63	$2.63
40%	1,164,389	Btu/h	$2.59	$2.59	$2.59	$2.10	$2.10	$2.10
30%	873,292	Btu/h	$1.94	$1.94	$1.94	$1.58	$1.58	$1.58
25%	727,743	Btu/h	$1.62	$1.62	$1.62	$1.31	$1.31	$1.31
20%	582,195	Btu/h	$1.29	$1.29	$1.29	$1.05	$1.05	$1.05
10%	291,097	Btu/h	$0.65	$0.65	$0.65	$0.53	$0.53	$0.53
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Useable Thermal Energy							
100%		$18.29	$6.80	$1.12	$12.69	$1.43	($1.88)
90%		$17.64	$6.16	$0.48	$12.16	$0.90	($2.41)
80%		$16.99	$5.51	($0.17)	$11.64	$0.38	($2.93)
75%		$16.67	$5.19	($0.49)	$11.37	$0.12	($3.19)
70%		$16.35	$4.86	($0.82)	$11.11	($0.15)	($3.46)
60%		$15.70	$4.22	($1.47)	$10.59	($0.67)	($3.98)
50%		$15.05	$3.57	($2.11)	$10.06	($1.20)	($4.51)
40%		$14.40	$2.92	($2.76)	$9.54	($1.72)	($5.03)
30%		$13.76	$2.27	($3.41)	$9.01	($2.25)	($5.56)
25%		$13.43	$1.95	($3.73)	$8.75	($2.51)	($5.82)
20%		$13.11	$1.63	($4.05)	$8.48	($2.77)	($6.08)
10%		$12.46	$0.98	($4.70)	$7.96	($3.30)	($6.61)
0%		$11.81	$0.33	($5.35)	$7.43	($3.82)	($7.13)

Value of Cogenerated Energy
Electrical Load Following
(Values are per engine per hour)

Load	Energy		Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
Fuel Input								
50.00%	4,623,500	Btu/h	($16.27)	($16.27)	($16.27)	($16.93)	($16.93)	($16.93)
Electrical Output								
50.00%	325	kW	$22.38	$14.73	$10.9[illegible]	[illegible]	[illegible]2.56	$10.35
Heat Recoverable and Useable								
100%	2,075,981	Btu/h	$4.62	$4.62	$4.62	$3.75	$3.75	$3.75
90%	1,868,383	Btu/h	$4.15	$4.15	$4.15	$3.37	$3.37	$3.37
80%	1,660,785	Btu/h	$3.69	$3.69	$3.69	$3.00	$3.00	$3.00
75%	1,556,986	Btu/h	$3.46	$3.46	$3.46	$2.81	$2.81	$2.81
70%	1,453,187	Btu/h	$3.23	$3.23	$3.23	$2.62	$2.62	$2.62
60%	1,245,589	Btu/h	$2.77	$2.77	$2.77	$2.25	$2.25	$2.25
50%	1,037,990	Btu/h	$2.31	$2.31	$2.31	$1.87	$1.87	$1.87
40%	830,392	Btu/h	$1.85	$1.85	$1.85	$1.50	$1.50	$1.50
30%	622,794	Btu/h	$1.38	$1.38	$1.38	$1.12	$1.12	$1.12
25%	518,995	Btu/h	$1.15	$1.15	$1.15	$0.94	$0.94	$0.94
20%	415,196	Btu/h	$0.92	$0.92	$0.92	$0.75	$0.75	$0.75
10%	207,598	Btu/h	$0.46	$0.46	$0.46	$0.37	$0.37	$0.37
0%	0	Btu/h	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Net Marginal Value of Energy

Useable Thermal Energy	Summer On-Peak	Summer Semi-Peak	Summer Off-Peak	Winter On-Peak	Winter Semi-Peak	Winter Off-Peak
100%	$10.73	$3.08	($0.70)	$6.87	($0.63)	($2.83)
90%	$10.27	$2.62	($1.16)	$6.49	($1.00)	($3.21)
80%	$9.80	$2.16	($1.63)	$6.12	($1.38)	($3.58)
75%	$9.57	$1.93	($1.86)	$5.93	($1.56)	($3.77)
70%	$9.34	$1.70	($2.09)	$5.75	($1.75)	($3.96)
60%	$8.88	$1.23	($2.55)	$5.37	($2.13)	($4.33)
50%	$8.42	$0.77	($3.01)	$5.00	($2.50)	($4.70)
40%	$7.96	$0.31	($3.47)	$4.62	($2.88)	($5.08)
30%	$7.50	($0.15)	($3.93)	$4.25	($3.25)	($5.45)
25%	$7.27	($0.38)	($4.16)	$4.06	($3.44)	($5.64)
20%	$7.04	($0.61)	($4.40)	$3.87	($3.63)	($5.83)
10%	$6.57	($1.07)	($4.86)	$3.50	($4.00)	($6.20)
0%	$6.11	($1.54)	($5.32)	$3.12	($4.37)	($6.58)

Appendix F

Thermal Energy Analyses for Scenarios 1 Through 12

TABLE F.1. Thermal Energy Analysis for Scenarios 1 - 3

	Operating Hours			Thermal Energy Recoverable		
	Summer (h/yr)	Winter (h/yr)	Total (h/yr)	Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
Alternatives 1-3						
Continuous Operation	3,672	5,088	8,760	243,276	337,089	580,365
On-Peak & Semi-Peak	1,696	2,384	4,080	112,363	157,944	270,307
On-Peak Operation	742	447	1,189	49,159	29,615	78,774

NCTS Forecasted Growth													
Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
End of Year				0	1	2	3	4	5	6	7	8	9
Load Increase		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Average Electrical Load (kW)	1,100	1,133	1,167	1,202	1,238	1,275	1,313	1,353	1,393	1,435	1,478	1,523	1,568
NCTS Required Thermal Energy (therms/yr)													
Summer													
Cooling	176,330	181,620	187,068	192,681	198,461	204,415	210,547	216,864	223,370	230,071	236,973	244,082	251,404
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	4,183	4,308	4,438	4,571	4,708	4,849	4,995	5,145	5,299	5,458	5,622	5,790	5,964
Total	180,513	185,928	191,506	197,251	203,169	209,264	215,542	222,008	228,668	235,529	242,594	249,872	257,368
Winter													
Cooling	234,460	241,494	248,739	256,201	263,887	271,803	279,958	288,356	297,007	305,917	315,095	324,547	334,284
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	5,797	5,971	6,150	6,335	6,525	6,720	6,922	7,130	7,343	7,564	7,791	8,024	8,265
Total	240,257	247,465	254,889	262,535	270,411	278,524	286,879	295,486	304,350	313,481	322,885	332,572	342,549
Thermal Energy Recoverable and Useable (therms/yr)													
Summer													
Continuous Operation	126,359	130,150	134,054	138,076	142,218	146,485	150,879	155,406	160,068	164,870	169,816	174,911	180,158
On-Peak & Semi-Peak	58,362	60,113	61,916	63,774	65,687	67,657	69,687	71,778	73,931	76,149	78,434	80,787	83,210
On-Peak Operation	25,533	26,299	27,088	27,901	28,738	29,600	30,488	31,403	32,345	33,315	34,315	35,344	36,404
Winter													
Continuous Operation	168,180	173,225	178,422	183,775	189,288	194,967	200,816	206,840	213,045	219,437	226,020	232,800	239,784
On-Peak & Semi-Peak	78,801	81,165	83,600	86,108	88,692	91,352	94,093	96,916	99,823	102,818	105,902	109,079	112,352
On-Peak Operation	14,775	15,218	15,675	16,145	16,630	17,129	17,642	18,172	18,717	19,278	19,857	20,452	21,066
Total													
Continuous Operation	294,539	303,375	312,476	321,851	331,506	341,451	351,695	362,246	373,113	384,307	395,836	407,711	419,942
On-Peak & Semi-Peak	137,163	141,278	145,516	149,882	154,378	159,010	163,780	168,693	173,754	178,967	184,336	189,866	195,562
On-Peak Operation	40,309	41,518	42,763	44,046	45,368	46,729	48,131	49,574	51,062	52,594	54,171	55,797	57,470

TABLE F.1. Thermal Energy Analysis for Scenarios 1 - 3 (contd)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1,615	1,664	1,714	1,765	1,818	1,873	1,929	1,987	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
258,947	266,715	274,716	282,958	291,447	300,190	309,196	318,472	320,542	320,542	320,542	320,542	320,542	320,542	320,542	320,542
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,143	6,327	6,517	6,712	6,914	7,121	7,335	7,555	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604
265,089	273,042	281,233	289,670	298,360	307,311	316,531	326,027	328,146	328,146	328,146	328,146	328,146	328,146	328,146	328,146
344,312	354,642	365,281	376,239	387,527	399,152	411,127	423,461	426,213	426,213	426,213	426,213	426,213	426,213	426,213	426,213
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8,513	8,768	9,032	9,302	9,582	9,869	10,165	10,470	10,538	10,538	10,538	10,538	10,538	10,538	10,538	10,538
352,826	363,410	374,313	385,542	397,108	409,021	421,292	433,931	436,751	436,751	436,751	436,751	436,751	436,751	436,751	436,751
185,563	191,129	196,863	202,769	208,852	215,118	221,571	228,219	229,702	229,702	229,702	229,702	229,702	229,702	229,702	229,702
85,708	88,278	90,926	93,654	96,463	99,357	102,338	105,408	108,093	108,093	108,093	108,093	108,093	108,093	108,093	108,093
37,497	38,621	39,780	40,974	42,203	43,469	44,773	46,116	46,416	46,416	46,416	46,416	46,416	46,416	46,416	46,416
246,978	254,387	262,019	269,879	277,976	286,315	294,904	303,752	305,726	305,726	305,726	305,726	305,726	305,726	305,726	305,726
115,722	119,194	122,770	126,453	130,246	134,154	138,179	142,324	143,249	143,249	143,249	143,249	143,249	143,249	143,249	143,249
21,696	22,349	23,019	23,710	24,421	25,154	25,908	26,686	26,859	26,859	26,859	26,859	26,859	26,859	26,859	26,859
432,540	445,517	458,882	472,649	486,828	501,433	516,476	531,970	535,428	535,428	535,428	535,428	535,428	535,428	535,428	535,428
201,429	207,472	213,696	220,107	226,710	233,511	240,517	247,732	249,342	249,342	249,342	249,342	249,342	249,342	249,342	249,342
59,195	60,970	62,799	64,683	66,624	68,623	70,681	72,802	73,275	73,275	73,275	73,275	73,275	73,275	73,275	73,275

TABLE F.2. Thermal Energy Analysis for Scenarios 4 - 6

	Operating Hours			Thermal Energy Recoverable		
	Summer (h/yr)	Winter (h/yr)	Total (h/yr)	Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
Alternatives 4-6						
Continuous Operation	3,672	5,088	8,760	502,246	695,923	1,198,169
On-Peak & Semi-Peak	1,696	2,384	4,080	231,974	326,077	558,051
On-Peak Operation	742	447	1,139	101,489	61,139	162,628

NCTS Forecasted Growth													
Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
End of Year				0	1	2	3	4	5	6	7	8	9
Load Increase		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Average Electrical Load (kW)	1,100	1,133	1,167	1,202	1,238	1,275	1,313	1,353	1,393	1,435	1,478	1,523	1,568
NCTS Required Thermal Energy (therms/yr)													
Summer													
Cooling	178,330	181,820	187,088	192,681	198,461	204,415	210,547	216,864	223,370	230,071	236,973	244,082	251,404
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	4,183	4,308	4,438	4,571	4,708	4,849	4,995	5,145	5,299	5,458	5,622	5,790	5,964
Total	180,513	185,928	191,508	197,251	203,169	209,264	215,542	222,008	228,668	235,529	242,594	249,872	257,368
Winter													
Cooling	234,460	241,494	248,739	256,201	263,887	271,803	279,958	288,356	297,007	305,917	315,095	324,547	334,284
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	5,797	5,971	6,150	6,335	6,525	6,720	6,922	7,130	7,343	7,564	7,791	8,024	8,265
Total	240,257	247,465	254,889	262,535	270,411	278,524	286,879	295,486	304,350	313,481	322,885	332,572	342,549
Thermal Energy Recoverable and Useable (therms/yr)													
Summer													
Continuous Operation	175,098	180,351	185,761	191,334	197,074	202,986	209,076	215,348	221,808	228,463	235,317	242,376	249,647
On-Peak & Semi-Peak	80,873	83,299	85,798	88,372	91,023	93,754	96,567	99,464	102,447	105,521	108,687	111,947	115,306
On-Peak Operation	35,382	36,443	37,537	38,663	39,823	41,017	42,248	43,515	44,821	46,165	47,550	48,977	50,446
Winter													
Continuous Operation	233,049	240,041	247,242	254,659	262,299	270,168	278,273	286,621	295,220	304,076	313,199	322,595	332,273
On-Peak & Semi-Peak	109,196	112,472	115,846	119,321	122,901	126,588	130,386	134,297	138,326	142,476	146,750	151,153	155,687
On-Peak Operation	20,474	21,088	21,721	22,373	23,044	23,735	24,447	25,181	25,936	26,714	27,516	28,341	29,191
Total													
Continuous Operation	408,147	420,391	433,003	445,993	459,373	473,154	487,349	501,969	517,028	532,539	548,515	564,971	581,920
On-Peak & Semi-Peak	190,069	195,771	201,644	207,694	213,924	220,342	226,952	233,761	240,774	247,997	255,437	263,100	270,993
On-Peak Operation	55,856	57,532	59,258	61,036	62,867	64,753	66,695	68,696	70,757	72,880	75,066	77,318	79,638

TABLE F.2. Thermal Energy Analysis for Scenarios 4 - 6 (contd)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.85%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1,815	1,864	1,714	1,765	1,818	1,873	1,929	1,987	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
258,947	266,715	274,716	282,958	291,447	300,190	309,196	318,472	320,542	320,542	320,542	320,542	320,542	320,542	320,542	320,542
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,143	6,327	6,517	6,712	6,914	7,121	7,335	7,555	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604
265,089	273,042	281,233	289,670	298,360	307,311	316,531	326,027	328,146	328,146	328,146	328,146	328,146	328,146	328,146	328,146
344,312	354,642	365,281	376,239	387,527	399,152	411,127	423,461	428,213	428,213	428,213	428,213	428,213	428,213	428,213	428,213
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8,513	8,768	9,032	9,302	9,582	9,869	10,165	10,470	10,538	10,538	10,538	10,538	10,538	10,538	10,538	10,538
352,826	363,410	374,313	385,542	397,108	409,021	421,292	433,931	438,751	438,751	438,751	438,751	438,751	438,751	438,751	438,751
257,137	264,851	272,796	280,980	289,410	298,092	307,035	316,246	318,301	318,301	318,301	318,301	318,301	318,301	318,301	318,301
118,765	122,328	125,997	129,777	133,671	137,681	141,811	146,066	147,015	147,015	147,015	147,015	147,015	147,015	147,015	147,015
51,960	53,518	55,124	56,778	58,481	60,235	62,042	63,904	64,319	64,319	64,319	64,319	64,319	64,319	64,319	64,319
342,241	352,508	363,083	373,976	385,195	396,751	408,653	420,913	423,649	423,649	423,649	423,649	423,649	423,649	423,649	423,649
160,358	165,169	170,124	175,228	180,484	185,899	191,476	197,220	198,502	198,502	198,502	198,502	198,502	198,502	198,502	198,502
30,067	30,969	31,898	32,855	33,841	34,856	35,902	36,979	37,219	37,219	37,219	37,219	37,219	37,219	37,219	37,219
599,377	617,359	635,880	654,956	674,605	694,843	715,688	737,159	741,950	741,950	741,950	741,950	741,950	741,950	741,950	741,950
279,123	287,496	296,121	305,005	314,155	323,580	333,287	343,286	345,517	345,517	345,517	345,517	345,517	345,517	345,517	345,517
82,027	84,487	87,022	89,633	92,322	95,091	97,944	100,882	101,538	101,538	101,538	101,538	101,538	101,538	101,538	101,538

TABLE F.3. Thermal Energy Analysis for Scenarios 7 - 9

	Operating Hours			Thermal Energy Recoverable		
Scenarios 7-9	Summer (h/yr)	Winter (h/yr)	Total (h/yr)	Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
Continuous Operation	3,672	5,088	8,760	346,881	480,645	827,526
On-Peak & Semi-Peak	1,696	2,384	4,080	160,215	225,208	385,423
On-Peak Operation	742	447	1,189	70,094	42,226	112,320

NCTS Forecasted Growth													
Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
End of Year				0	1	2	3	4	5	6	7	8	9
Load Increase		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Average Electrical Load (kW)	1,100	1,133	1,167	1,202	1,238	1,275	1,313	1,353	1,393	1,435	1,478	1,523	1,568
NCTS Required Thermal Energy (therms/yr)													
Summer													
Cooling	178,330	181,620	187,068	192,681	198,461	204,415	210,547	216,864	223,370	230,071	236,973	244,082	251,404
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	4,183	4,308	4,438	4,571	4,708	4,849	4,995	5,145	5,299	5,458	5,622	5,790	5,964
Total	180,513	185,928	191,506	197,251	203,169	209,264	215,542	222,008	228,668	235,529	242,594	249,872	257,368
Winter													
Cooling	234,460	241,494	248,739	256,201	263,887	271,803	279,958	288,356	297,007	305,917	315,095	324,547	334,284
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	5,797	5,971	6,150	6,335	6,525	6,720	6,922	7,130	7,343	7,564	7,791	8,024	8,265
Total	240,257	247,465	254,889	262,535	270,411	278,524	286,879	295,486	304,350	313,481	322,885	332,572	342,549
Thermal Energy Recoverable and Useable (therms/yr)													
Summer													
Continuous Operation	175,098	180,351	185,761	191,334	197,074	202,986	209,076	215,348	221,808	228,463	235,317	242,376	249,647
On-Peak & Semi-Peak	80,873	83,299	85,798	88,372	91,023	93,754	96,567	99,464	102,447	105,521	108,687	111,947	115,306
On-Peak Operation	35,382	36,443	37,537	38,663	39,823	41,017	42,248	43,515	44,821	46,165	47,550	48,977	50,446
Winter													
Continuous Operation	233,049	240,041	247,242	254,659	262,299	270,168	278,273	286,621	295,220	304,076	313,199	322,595	332,273
On-Peak & Semi-Peak	109,198	112,472	115,846	119,321	122,901	126,588	130,386	134,297	138,326	142,476	146,750	151,153	155,687
On-Peak Operation	20,474	21,088	21,721	22,373	23,044	23,735	24,447	25,181	25,936	26,714	27,516	28,341	29,191
Total													
Continuous Operation	408,147	420,391	433,003	445,993	459,373	473,154	487,349	501,969	517,028	532,539	548,515	564,971	581,920
On-Peak & Semi-Peak	190,069	195,771	201,644	207,694	213,924	220,342	226,952	233,761	240,774	247,997	255,437	263,100	270,993
On-Peak Operation	55,856	57,532	59,258	61,036	62,867	64,753	66,695	68,696	70,757	72,880	75,066	77,318	79,638

TABLE F.3. Thermal Energy Analysis for Scenarios 7 - 9 (contd)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1,615	1,664	1,714	1,765	1,818	1,873	1,929	1,987	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
258,947	266,715	274,716	282,958	291,447	300,190	309,196	318,472	320,542	320,542	320,542	320,542	320,542	320,542	320,542	320,542
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,143	6,327	6,517	6,712	6,914	7,121	7,335	7,555	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604
265,089	273,042	281,233	289,670	298,360	307,311	316,531	326,027	328,146	328,146	328,146	328,146	328,146	328,146	328,146	328,146
344,312	354,642	365,281	376,239	387,527	399,152	411,127	423,461	426,213	426,213	426,213	426,213	426,213	426,213	426,213	426,213
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8,513	8,768	9,032	9,302	9,582	9,869	10,165	10,470	10,538	10,538	10,538	10,538	10,538	10,538	10,538	10,538
352,826	363,410	374,313	385,542	397,108	409,021	421,292	433,931	436,751	436,751	436,751	436,751	436,751	436,751	436,751	436,751
257,137	264,851	272,796	280,980	289,410	298,092	307,035	316,246	318,301	318,301	318,301	318,301	318,301	318,301	318,301	318,301
118,765	122,328	125,997	129,777	133,671	137,681	141,811	146,066	147,015	147,015	147,015	147,015	147,015	147,015	147,015	147,015
51,960	53,518	55,124	56,778	58,481	60,235	62,042	63,904	64,319	64,319	64,319	64,319	64,319	64,319	64,319	64,319
342,241	352,508	363,083	373,976	385,195	396,751	408,653	420,913	423,649	423,649	423,649	423,649	423,649	423,649	423,649	423,649
160,358	165,169	170,124	175,228	180,484	185,899	191,476	197,220	198,502	198,502	198,502	198,502	198,502	198,502	198,502	198,502
30,067	30,969	31,898	32,855	33,841	34,856	35,902	36,979	37,219	37,219	37,219	37,219	37,219	37,219	37,219	37,219
599,377	617,359	635,880	654,956	674,605	694,843	715,688	737,159	741,950	741,950	741,950	741,950	741,950	741,950	741,950	741,950
279,123	287,496	296,121	305,005	314,155	323,580	333,287	343,286	345,517	345,517	345,517	345,517	345,517	345,517	345,517	345,517
82,027	84,487	87,022	89,633	92,322	95,091	97,944	100,882	101,538	101,538	101,538	101,538	101,538	101,538	101,538	101,538

TABLE F.4. Thermal Energy Analysis for Scenarios 10 - 12

Scenarios 10-12	Operating Hours Summer (h/yr)	Operating Hours Winter (h/yr)	Operating Hours Total (h/yr)	Thermal Energy Recoverable Summer (therms/yr)	Thermal Energy Recoverable Winter (therms/yr)	Thermal Energy Recoverable Total (therms/yr)
Continuous Operation	3,672	5,088	8,760	721,985	1,000,397	1,722,382
On-Peak & Semi-Peak	1,696	2,384	4,080	333,466	468,740	802,206
On-Peak Operation	742	447	1,189	145,891	87,889	233,780

NCTS Forecasted Growth													
Year	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
End of Year				0	1	2	3	4	5	6	7	8	9
Load Increase		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Average Electrical Load (kW)	1,100	1,133	1,167	1,202	1,238	1,275	1,313	1,353	1,393	1,435	1,478	1,523	1,568
NCTS Required Thermal Energy (therms/yr)													
Summer													
Cooling	176,330	181,620	187,068	192,681	198,461	204,415	210,547	216,864	223,370	230,071	236,973	244,082	251,404
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	4,183	4,308	4,438	4,571	4,708	4,849	4,995	5,145	5,299	5,458	5,622	5,790	5,964
Total	180,513	185,928	191,506	197,251	203,169	209,264	215,542	222,008	228,668	235,529	242,594	249,872	257,368
Winter													
Cooling	234,460	241,494	248,739	256,201	263,887	271,803	279,958	288,356	297,007	305,917	315,095	324,547	334,284
Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-heat	0	0	0	0	0	0	0	0	0	0	0	0	0
DHW	5,797	5,971	6,150	6,335	6,525	6,720	6,922	7,130	7,343	7,564	7,791	8,024	8,265
Total	240,257	247,465	254,889	262,535	270,411	278,524	286,879	295,486	304,350	313,481	322,885	332,572	342,549
Thermal Energy Recoverable and Useable (therms/yr)													
Summer													
Continuous Operation	175,098	180,351	185,761	191,334	197,074	202,986	209,076	215,348	221,808	228,463	235,317	242,376	249,647
On-Peak & Semi-Peak	80,873	83,299	85,798	88,372	91,023	93,754	96,567	99,464	102,447	105,521	108,687	111,947	115,306
On-Peak Operation	35,382	36,443	37,537	38,663	39,823	41,017	42,248	43,515	44,821	46,165	47,550	48,977	50,446
Winter													
Continuous Operation	233,049	240,041	247,242	254,659	262,299	270,168	278,273	286,621	295,220	304,076	313,199	322,595	332,273
On-Peak & Semi-Peak	109,196	112,472	115,846	119,321	122,901	126,588	130,386	134,297	138,326	142,476	146,750	151,153	155,687
On-Peak Operation	20,474	21,088	21,721	22,373	23,044	23,735	24,447	25,181	25,936	26,714	27,516	28,341	29,191
Total													
Continuous Operation	408,147	420,391	433,003	445,993	459,373	473,154	487,349	501,969	517,028	532,539	548,515	564,971	581,920
On-Peak & Semi-Peak	190,069	195,771	201,644	207,694	213,924	220,342	226,952	233,761	240,774	247,997	255,437	263,100	270,993
On-Peak Operation	55,856	57,532	59,258	61,036	62,867	64,753	66,695	68,696	70,757	72,880	75,066	77,318	79,638

TABLE F.4. Thermal Energy Analysis for Scenarios 10 - 12 (contd)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	0.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1,815	1,864	1,714	1,765	1,818	1,873	1,929	1,987	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
258,947	266,715	274,716	282,958	291,447	300,190	309,196	318,472	320,542	320,542	320,542	320,542	320,542	320,542	320,542	320,542
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6,143	6,327	6,517	6,712	6,914	7,121	7,335	7,555	7,604	7,604	7,604	7,604	7,604	7,604	7,604	7,604
265,089	273,042	281,233	289,670	298,360	307,311	316,531	326,027	328,146	328,146	328,146	328,146	328,146	328,146	328,146	328,146
344,312	354,642	365,281	376,239	387,527	399,152	411,127	423,461	428,213	428,213	428,213	428,213	428,213	428,213	428,213	428,213
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8,513	8,768	9,032	9,302	9,582	9,869	10,165	10,470	10,538	10,538	10,538	10,538	10,538	10,538	10,538	10,538
352,826	363,410	374,313	385,542	397,108	409,021	421,292	433,931	438,751	438,751	438,751	438,751	438,751	438,751	438,751	438,751
257,137	264,851	272,796	280,980	289,410	298,092	307,035	316,246	318,301	318,301	318,301	318,301	318,301	318,301	318,301	318,301
118,765	122,328	125,997	129,777	133,671	137,681	141,811	146,066	147,015	147,015	147,015	147,015	147,015	147,015	147,015	147,015
51,980	53,518	55,124	56,778	58,481	60,235	62,042	63,904	64,319	64,319	64,319	64,319	64,319	64,319	64,319	64,319
342,241	352,508	363,083	373,976	385,195	396,751	408,653	420,913	423,649	423,649	423,649	423,649	423,649	423,649	423,649	423,649
160,358	165,169	170,124	175,228	180,484	185,899	191,476	197,220	198,502	198,502	198,502	198,502	198,502	198,502	198,502	198,502
30,067	30,969	31,898	32,855	33,841	34,856	35,902	36,979	37,219	37,219	37,219	37,219	37,219	37,219	37,219	37,219
599,377	617,359	635,880	654,956	674,605	694,843	715,688	737,159	741,950	741,950	741,950	741,950	741,950	741,950	741,950	741,950
279,123	287,496	296,121	305,005	314,155	323,580	333,287	343,286	345,517	345,517	345,517	345,517	345,517	345,517	345,517	345,517
82,027	84,487	87,022	89,633	92,322	95,091	97,944	100,882	101,538	101,538	101,538	101,538	101,538	101,538	101,538	101,538

Appendix G

Energy Analyses for Scenarios 1 Through 12

TABLE G.1. Energy Analysis for Scenario 1

Reciprocating Engine Data:				
Number of Engines	2	Units operating		
Generator Capacity	600	kW-each	derated	
Contracted Demand	2,600	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh		
Thermal Recovery	49%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	Y	Y

Available Operating Hours	8,760	h/yr	
Scheduled Downtime	0	h/yr	Assumes 2 of 4 engines always operating.
Net Operating Hours	8,760	h/yr	
Net Utilization of Hours	100%		
Load Utilization Factor	94%	(average engine load factor when in operation)	
Powerhouse Load	1.25%	(percent of load used in powerhouse)	

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	1,976	$0.03369	
	sub-total	3,672		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	2,704	$0.03186	
	sub-total	5,088		
	Total	8,760		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	2,904	$0.30895	0.107	therm/kWh
	Non-cogen Rate	2,904	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	5,856	$0.30375		
	Non-cogen Rate	5,856	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	3,672	$0.222
Winter	Marginal Rate	5,088	$0.180
		8,760	

TABLE G.1. Energy Analysis for Scenario 1 (contd)

Natural Gas Consumed:		Energy	(therm/yr)	Value	($/yr)
Winter	Cogen Rate	357,196		$110,356	
	Non-cogen Rate	48,840		$17,886	
	sub-total	406,036		$128,242	
Summer	Cogen Rate	720,296		$218,790	
	Non-cogen Rate	98,488		$34,653	
	sub-total	818,783		$253,443	
Total		1,224,819		$381,685	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	836,976		1,200	
	Semi-Peak	1,076,112		1,200	
	Off-Peak	2,228,928			
Winter	On-Peak	504,216		1,200	
	Semi-Peak	2,184,936		1,200	
	Off-Peak	3,050,112			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	826,514		1,185		$136,249	
	Semi-Peak	1,062,661		1,185		$55,517	
	Off-Peak	2,201,066				$74,154	
	sub-total	4,090,241				$265,921	
Winter	On-Peak	497,913		1,185		$48,726	
	Semi-Peak	2,157,624		1,185		$93,656	
	Off-Peak	3,011,986				$95,962	
	sub-total	5,667,523				$238,345	
Total		9,757,764				$504,265	

Thermal Energy Recoverable:	Summer		Winter		Total	
	243,276	therms/yr	337,089	therms/yr	580,365	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.1. Energy Analysis for Scenario 1 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	126,359	14,326	$28,100
Winter	168,180	19,068	$30,345
Total	294,539	33,394	$58,444

Summary of Calculations:

Natural Gas Fuel Cost	($381,685)	/yr
Electrical Savings	$504,265	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$58,444	/yr
Net Energy Savings	150,137	/yr

Average SDG&E/FERC Efficiency 43.57%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.2. Energy Analysis for Scenario 2

Reciprocating Engine Data:				
Number of Engines	2	Units operating		
Generator Capacity	600	kW-each	derated	
Contracted Demand	2,600	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh		
Thermal Recovery	49%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	N	N

Available Operating Hours	8,760	h/yr	
Scheduled Downtime	0	h/yr	Assumes 2 of 4 engines always operating.
Net Operating Hours	8,760	h/yr	
Net Utilization of Hours	100%		
Load Utilization Factor	94%	(average engine load factor when in operation)	
Powerhouse Load	1.25%	(percent of load used in powerhouse)	

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	1,696		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	2,384		
	Total	4,080		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	1,344	$0.30895	0.107	therm/kWh
	Non-cogen Rate	1,344	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	2,736	$0.30375		
	Non-cogen Rate	2,736	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	1,696	$0.222
Winter	Marginal Rate	2,384	$0.180
		4,080	

TABLE G.2. Energy Analysis for Scenario 2 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	165,314		$51,074	
	Non-cogen Rate	22,604		$8,278	
	sub-total	187,918		$59,352	
Summer	Cogen Rate	336,532		$102,221	
	Non-cogen Rate	46,015		$16,190	
	sub-total	382,546		$118,412	
Total		570,464		$177,763	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	836,976		1,200	
	Semi-Peak	1,076,112		1,200	
	Off-Peak	0			
Winter	On-Peak	504,216		1,200	
	Semi-Peak	2,184,936		1,200	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	826,514		1,185		$136,249	
	Semi-Peak	1,062,661		1,185		$55,517	
	Off-Peak	0				$0	
	sub-total	1,889,174				$191,767	
Winter	On-Peak	497,913		1,185		$48,726	
	Semi-Peak	2,157,624		1,185		$93,656	
	Off-Peak	0				$0	
	sub-total	2,655,538				$142,383	
Total		4,544,712				$334,150	

Thermal Energy Recoverable:	Summer		Winter		Total	
	112,363	therms/yr	157,944	therms/yr	270,307	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.2. Energy Analysis for Scenario 2 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	58,362	6,617	$12,979
Winter	78,801	8,934	$14,218
Total	137,163	15,551	$27,197

Summary of Calculations:

Natural Gas Fuel Cost	($177,763)	/yr
Electrical Savings	$334,150	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$27,197	/yr
Net Energy Savings	152,695	/yr

Average SDG&E/FERC Efficiency 43.57%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.3. Energy Analysis for Scenario 3

Reciprocating Engine Data:					
Number of Engines	2	Units operating			
Generator Capacity	600	kW-each	derated		
Contracted Demand	2,600	kW @		$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh			
Thermal Recovery	49%	(percent of total energy)			

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	N	N
Off-Peak	N	N

Available Operating Hours	8,760	h/yr	
Scheduled Downtime	0	h/yr	Assumes 2 of 4 engines always operating.
Net Operating Hours	8,760	h/yr	
Net Utilization of Hours	100%		
Load Utilization Factor	94%	(average engine load factor when in operation)	
Powerhouse Load	1.25%	(percent of load used in powerhouse)	

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	0	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	742		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	0	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	447		
	Total	1,189		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	252	$0.30895	0.107	therm/kWh
	Non-cogen Rate	252	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	937	$0.30375		
	Non-cogen Rate	937	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	742	$0.222
Winter	Marginal Rate	447	$0.180
		1,189	

TABLE G.3. Energy Analysis for Scenario 3 (contd)

Natural Gas Consumed:		Energy (therms/yr)	Value ($/yr)
Winter	Cogen Rate	30,996	$9,576
	Non-cogen Rate	4,238	$1,552
	sub-total	35,235	$11,128
Summer	Cogen Rate	115,252	$35,008
	Non-cogen Rate	15,759	$5,545
	sub-total	131,011	$40,553
Total		166,245	$51,681

Electricity Generated:		Energy (kWh/yr)	Demand (kW)
Summer	On-Peak	836,976	1,200
	Semi-Peak	0	0
	Off-Peak	0	
Winter	On-Peak	504,216	1,200
	Semi-Peak	0	0
	Off-Peak	0	

Net Electricity Generated:		Energy (kWh/yr)	Demand (kW)	Value ($/yr)
Summer	On-Peak	826,514	1,185	$136,249
	Semi-Peak	0	0	$0
	Off-Peak	0		$0
	sub-total	826,514		$136,249
Winter	On-Peak	497,913	1,185	$48,726
	Semi-Peak	0	0	$0
	Off-Peak	0		$0
	sub-total	497,913		$48,726
Total		1,324,427		$184,976

Thermal Energy Recoverable:	Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
	49,159	29,615	78,773

Required Thermal Energy:		Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
	Cooling	176,330	234,460	410,790
	Heating	0	0	0
	Re-Heat	0	0	0
	DHW	4,183	5,797	9,980
	sub-total	180,513	240,257	420,770

TABLE G.3. Energy Analysis for Scenario 3 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	25,533	2,895	$5,678
Winter	14,775	1,675	$2,666
Total	40,309	4,570	$8,344

Summary of Calculations:

Natural Gas Fuel Cost	($51,681)	/yr
Electrical Savings	$184,976	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$8,344	/yr
Net Energy Savings	110,751	/yr

Average SDG&E/FERC Efficiency 43.68%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.4. Energy Analysis for Scenario 4

Reciprocating Engine Data:				
Number of Engines	4	Units operating		
Generator Capacity	600	kW-each	derated	
Contracted Demand	2,600	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh		
Thermal Recovery	49%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	Y	Y

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	1,976	$0.03369	
	sub-total	3,672		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	2,704	$0.03186	
	sub-total	5,088		
	Total	8,760		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	2,904	$0.30895	0.107	therm/kWh
	Non-cogen Rate	2,904	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	5,856	$0.30375		
	Non-cogen Rate	5,856	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	3,672	$0.222
Winter	Marginal Rate	5,088	$0.180
		8,760	

TABLE G.4. Energy Analysis for Scenario 4 (contd)

Natural Gas Consumed:		Energy (therms/yr)	Value ($/yr)
Winter	Cogen Rate	0	$0
	Non-cogen Rate	838,265	$306,990
	sub-total	838,265	$306,990
Summer	Cogen Rate	0	$0
	Non-cogen Rate	1,690,386	$594,762
	sub-total	1,690,386	$594,762
Total		2,528,652	$901,752

Electricity Generated:		Energy (kWh/yr)	Demand (kW)
Summer	On-Peak	1,727,945	2,400
	Semi-Peak	2,221,644	2,400
	Off-Peak	4,601,644	-
Winter	On-Peak	1,040,959	2,400
	Semi-Peak	4,510,822	2,400
	Off-Peak	6,296,986	

Net Electricity Generated:		Energy (kWh/yr)	Demand (kW)	Value ($/yr)
Summer	On-Peak	1,706,346	2,370	$276,170
	Semi-Peak	2,193,873	2,370	$114,142
	Off-Peak	4,544,123		$153,092
	sub-total	8,444,342		$543,404
Winter	On-Peak	1,027,947	2,370	$99,435
	Semi-Peak	4,454,437	2,370	$192,691
	Off-Peak	6,218,274		$198,114
	sub-total	11,700,658		$490,240
Total		20,145,000		$1,033,644

Thermal Energy Recoverable:	Summer	Winter	Total
	502,246 therms/yr	695,923 therms/yr	1,198,169 therms/yr

Required Thermal Energy:		Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
	Cooling	176,330	234,460	410,790
	Heating	0	0	0
	Re-Heat	0	0	0
	DHW	4,183	5,797	9,980
	sub-total	180,513	240,257	420,770

TABLE G.4. Energy Analysis for Scenario 4 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	175,156	19,859	$38,951
Winter	233,126	26,431	$42,063
Total	408,281	46,290	$81,014

Summary of Calculations:

Natural Gas Fuel Cost	($901,752)	/yr
Electrical Savings	$1,033,644	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$81,014	/yr
Net Energy Savings	182,018	/yr

Average SDG&E/FERC Efficiency 39.18%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

TABLE G.5. Energy Analysis for Scenario 5

Reciprocating Engine Data:				
Number of Engines	4	Units operating		
Generator Capacity	600	kW-each	derated	
Contracted Demand	2,600	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh		
Thermal Recovery	49%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	1,696		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	2,384		
	Total	4,080		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	1,344	$0.30895	0.107	therm/kWh
	Non-cogen Rate	1,344	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	2,736	$0.30375		
	Non-cogen Rate	2,736	$0.35185		

Steam Rate Schedule:			
Summer	Marginal Rate	1,696	$0.222
Winter	Marginal Rate	2,384	$0.180
		4,080	

TABLE G.5. Energy Analysis for Scenario 5 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	0		$0	
	Non-cogen Rate	387,958		$142,078	
	sub-total	387,958		$142,078	
Summer	Cogen Rate	0		$0	
	Non-cogen Rate	789,771		$277,881	
	sub-total	789,771		$277,881	
Total		1,177,728		$419,959	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	1,727,945		2,400	
	Semi-Peak	2,221,644		2,400	
	Off-Peak	0			
Winter	On-Peak	1,040,959		2,400	
	Semi-Peak	4,510,822		2,400	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	1,706,346		2,370		$276,170	
	Semi-Peak	2,193,873		2,370		$114,142	
	Off-Peak	0				$0	
	sub-total	3,900,219				$390,313	
Winter	On-Peak	1,027,947		2,370		$99,435	
	Semi-Peak	4,454,437		2,370		$192,691	
	Off-Peak	0				$0	
	sub-total	5,482,384				$292,126	
Total		9,382,603				$682,439	

Thermal Energy Recoverable:	Summer		Winter		Total	
	231,974	therms/yr	326,077	therms/yr	558,051	therms/yr

Required Thermal Energy:	Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
Cooling	176,330		234,460		410,790	
Heating	0		0		0	
Re-Heat	0		0		0	
DHW	4,183		5,797		9,980	
sub-total	180,513		240,257		420,770	

TABLE G.5. Energy Analysis for Scenario 5 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	80,900	9,172	$17,990
Winter	109,232	12,385	$19,709
Total	190,132	21,557	$37,699

Summary of Calculations:

Natural Gas Fuel Cost	($419,959)	/yr
Electrical Savings	$682,439	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$37,699	/yr
Net Energy Savings	269,291	/yr

Average SDG&E/FERC Efficiency 39.18%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

TABLE G.6. Energy Analysis for Scenario 6

Reciprocating Engine Data:					
Number of Engines	4	Units operating			
Generator Capacity	600	kW-each	derated		
Contracted Demand	2,600	kW @		$0.99	/kW-month (back-up)
Heat Rate (HHV)	12,011	Btu/kWh			
Thermal Recovery	49%	(percent of total energy)			

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	N	N
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	0	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	742		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	0	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	447		
	Total	1,189		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	252	$0.30895	0.107	therm/kWh
	Non-cogen Rate	252	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	937	$0.30375		
	Non-cogen Rate	937	$0.35185		

Steam Rate Schedule:		Hours/Yr		Energy	($/therm)
Summer	Marginal Rate	742	hrs/yr	$0.222	/therm
Winter	Marginal Rate	447	hrs/yr	$0.180	/therm
		1,189	hrs/yr		

TABLE G.6. Energy Analysis for Scenario 6 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	0		$0	
	Non-cogen Rate	72,742		$26,640	
	sub-total	72,742		$26,640	
Summer	Cogen Rate	0		$0	
	Non-cogen Rate	270,473		$95,166	
	sub-total	270,473		$95,166	
Total		343,215		$121,806	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	1,727,945		2,400	
	Semi-Peak	0		0	
	Off-Peak	0			
Winter	On-Peak	1,040,959		2,400	
	Semi-Peak	0		0	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	1,706,346		2,370		$276,170	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	1,706,346				$276,170	
Winter	On-Peak	1,027,947		2,370		$99,435	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	1,027,947				$99,435	
Total		2,734,293				$375,605	

Thermal Energy Recoverable:	Summer		Winter		Total	
	101,489	therms/yr	61,139	therms/yr	162,628	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.6. Energy Analysis for Scenario 6 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	35,394	4,013	$7,871
Winter	20,481	2,322	$3,695
Total	55,875	6,335	$11,566

Summary of Calculations:

Natural Gas Fuel Cost	($121,806)	/yr
Electrical Savings	$375,605	/yr
SDG&E Back-up Cost	($30,888)	/yr
Thermal Savings	$11,566	/yr
Net Energy Savings	234,478	/yr

Average SDG&E/FERC Efficiency 39.26%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

TABLE G.7. Energy Analysis for Scenario 7

Reciprocating Engine Data:				
Number of Engines	4	Units operating		
Generator Capacity	610	kW-each		
Contracted Demand	2,440	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	10,500	Btu/kWh		
Thermal Recovery	38%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	Y	Y

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	1,976	$0.03369	
	sub-total	3,672		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	2,704	$0.03186	
	sub-total	5,088		
	Total	8,760		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	2,904	$0.30895	0.107	therm/kWh
	Non-cogen Rate	2,904	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	5,856	$0.30375		
	Non-cogen Rate	5,856	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	3,672	$0.222
Winter	Marginal Rate	5,088	$0.180
		8,760	

TABLE G.7. Energy Analysis for Scenario 7 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	745,024		$230,175	
	Non-cogen Rate	0		$0	
	sub-total	745,024		$230,175	
Summer	Cogen Rate	1,502,362		$456,343	
	Non-cogen Rate	0		$0	
	sub-total	1,502,362		$456,343	
Total		2,247,386		$686,518	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	1,756,744		2,440	
	Semi-Peak	2,258,671		2,440	
	Off-Peak	4,678,338			
Winter	On-Peak	1,058,308		2,440	
	Semi-Peak	4,586,002		2,440	
	Off-Peak	6,401,936			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	1,734,785		2,410		$280,773	
	Semi-Peak	2,230,438		2,410		$116,045	
	Off-Peak	4,619,859				$155,643	
	sub-total	8,585,082				$552,461	
Winter	On-Peak	1,045,079		2,410		$101,092	
	Semi-Peak	4,528,677		2,410		$195,903	
	Off-Peak	6,321,912				$201,416	
	sub-total	11,895,668				$498,411	
Total		20,480,750				$1,050,872	

Thermal Energy Recoverable:	Summer		Winter		Total	
	346,881	therms/yr	480,645	therms/yr	827,526	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.7. Energy Analysis for Scenario 7 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	175,156	19,859	$38,951
Winter	233,126	26,431	$42,063
Total	408,281	46,290	$81,014

Summary of Calculations:

Natural Gas Fuel Cost	($686,518)	/yr
Electrical Savings	$1,050,872	/yr
SDG&E Back-up Cost	($28,987)	/yr
Thermal Savings	$81,014	/yr
Net Energy Savings	416,381	/yr

Average SDG&E/FERC Efficiency 44.65%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.8. Energy Analysis for Scenario 8

Reciprocating Engine Data:				
Number of Engines	4	Units operating		
Generator Capacity	610	kW-each		
Contracted Demand	2,440	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	10,500	Btu/kWh		
Thermal Recovery	38%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	1,696		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	2,384		
	Total	4,080		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	1,344	$0.30895	0.107	therm/kWh
	Non-cogen Rate	1,344	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	2,736	$0.30375		
	Non-cogen Rate	2,736	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	1,696	$0.222
Winter	Marginal Rate	2,384	$0.180
		4,080	

TABLE G.8. Energy Analysis for Scenario 8 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	344,804		$106,527	
	Non-cogen Rate	0		$0	
	sub-total	344,804		$106,527	
Summer	Cogen Rate	701,923		$213,209	
	Non-cogen Rate	0		$0	
	sub-total	701,923		$213,209	
Total		1,046,728		$319,737	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	1,756,744		2,440	
	Semi-Peak	2,258,671		2,440	
	Off-Peak	0			
Winter	On-Peak	1,058,308		2,440	
	Semi-Peak	4,586,002		2,440	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	1,734,785		2,410		$280,773	
	Semi-Peak	2,230,438		2,410		$116,045	
	Off-Peak	0				$0	
	sub-total	3,965,223				$396,818	
Winter	On-Peak	1,045,079		2,410		$101,092	
	Semi-Peak	4,528,677		2,410		$195,903	
	Off-Peak	0				$0	
	sub-total	5,573,757				$296,995	
Total		9,538,979				$693,813	

Thermal Energy Recoverable:	Summer		Winter		Total	
	160,215	therms/yr	225,208	therms/yr	385,423	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.8. Energy Analysis for Scenario 8 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	80,900	9,172	$17,990
Winter	109,232	12,385	$19,709
Total	190,132	21,557	$37,699

Summary of Calculations:

Natural Gas Fuel Cost	($319,737)	/yr
Electrical Savings	$693,813	/yr
SDG&E Back-up Cost	($28,987)	/yr
Thermal Savings	$37,699	/yr
Net Energy Savings	382,788	/yr

Average SDG&E/FERC Efficiency 44.65%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.9. Energy Analysis for Scenario 9

Reciprocating Engine Data:				
Number of Engines	4	Units operating		
Generator Capacity	610	kW-each		
Contracted Demand	2,440	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	10,500	Btu/kWh		
Thermal Recovery	38%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	N	N
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	0	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	742		
Winter	On-Peak	447	$0.03171	$2.17
	Semi-Peak	0	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	447		
	Total	1,189		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	252	$0.30895	0.107	therm/kWh
	Non-cogen Rate	252	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	937	$0.30375		
	Non-cogen Rate	937	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	742	$0.222
Winter	Marginal Rate	447	$0.180
		1,189	

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	64,651		$19,974	
	Non-cogen Rate	0		$0	
	sub-total	64,651		$19,974	
Summer	Cogen Rate	240,388		$73,018	
	Non-cogen Rate	0		$0	
	sub-total	240,388		$73,018	
Total		305,039		$92,992	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	1,756,744		2,440	
	Semi-Peak	0		0	
	Off-Peak	0			
Winter	On-Peak	1,058,308		2,440	
	Semi-Peak	0		0	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	1,734,785		2,410		$280,773	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	1,734,785				$280,773	
Winter	On-Peak	1,045,079		2,410		$101,092	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	1,045,079				$101,092	
Total		2,779,864				$381,865	

Thermal Energy Recoverable:	Summer		Winter		Total	
	70,094	therms/yr	42,226	therms/yr	112,321	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	35,394	4,013	$7,871
Winter	20,481	2,322	$3,695
Total	55,875	6,335	$11,566

Summary of Calculations:

Natural Gas Fuel Cost	($92,992)	/yr
Electrical Savings	$381,865	/yr
SDG&E Back-up Cost	($28,987)	/yr
Thermal Savings	$11,566	/yr
Net Energy Savings	271,453	/yr

Average SDG&E/FERC Efficiency 44.74%

42.5% or greater required for cogen gas rate

Does qualify for cogen gas rate.

TABLE G.10. Energy Analysis for Scenario 10

Gas Turbine Engine Data:

Number of Engines	2	Units operating		
Generator Capacity	1,540	kW-each		
Contracted Demand	3,080	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	14,620	Btu/kWh		
Thermal Recovery	45%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	Y	Y

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	1,976	$0.03369	
	sub-total	3,672		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	2,704	$0.03186	
	sub-total	5,088		
	Total	8,760		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	2,904	$0.30895	0.107	therm/kWh
	Non-cogen Rate	2,904	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	5,856	$0.30375		
	Non-cogen Rate	5,856	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	3,672	$0.222
Winter	Marginal Rate	5,088	$0.180
		8,760	

TABLE G.10. Energy Analysis for Scenario 10 (contd)

Natural Gas Consumed:		Energy (therms/yr)	Value ($/yr)
Winter	Cogen Rate	0	$0
	Non-cogen Rate	1,309,451	$479,547
	sub-total	1,309,451	$479,547
Summer	Cogen Rate	0	$0
	Non-cogen Rate	2,640,546	$929,076
	sub-total	2,640,546	$929,076
Total		3,949,997	$1,408,623

Electricity Generated:		Energy (kWh/yr)	Demand (kW)
Summer	On-Peak	2,217,530	3,080
	Semi-Peak	2,851,110	3,080
	Off-Peak	5,905,443	
Winter	On-Peak	1,335,897	3,080
	Semi-Peak	5,788,888	3,080
	Off-Peak	8,081,132	

Net Electricity Generated:		Energy (kWh/yr)	Demand (kW)	Value ($/yr)
Summer	On-Peak	2,189,811	3,042	$354,419
	Semi-Peak	2,815,471	3,042	$146,483
	Off-Peak	5,831,625		$196,467
	sub-total	10,836,906		$697,369
Winter	On-Peak	1,319,199	3,042	$127,608
	Semi-Peak	5,716,527	3,042	$247,287
	Off-Peak	7,980,118		$254,247
	sub-total	15,015,844		$629,142
Total		25,852,750		$1,326,510

Thermal Energy Recoverable:	Summer	Winter	Total
	721,985 therms/yr	1,000,397 therms/yr	1,722,382 therms/yr

Required Thermal Energy:	Summer (therms/yr)	Winter (therms/yr)	Total (therms/yr)
Cooling	176,330	234,460	410,790
Heating	0	0	0
Re-Heat	0	0	0
DHW	4,183	5,797	9,980
sub-total	180,513	240,257	420,770

TABLE G.10. Energy Analysis for Scenario 10 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	175,156	19,859	$38,951
Winter	233,126	26,431	$42,063
Total	408,281	46,290	$81,014

Summary of Calculations:

Natural Gas Fuel Cost	($1,408,623)	/yr
Electrical Savings	$1,326,510	/yr
SDG&E Back-up Cost	($36,590)	/yr
Thermal Savings	$81,014	/yr
Net Energy Savings	(37,689)	/yr

Average SDG&E/FERC Efficiency 30.56%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

TABLE G.11. Energy Analysis for Scenario 11

Gas Turbine Engine Data:

Number of Engines	2	Units operating		
Generator Capacity	1,540	kW-each		
Contracted Demand	3,080	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	14,620	Btu/kWh		
Thermal Recovery	45%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	Y	Y
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	954	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	1,696		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	1,937	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	2,384		
	Total	4,080		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	1,344	$0.30895	0.107	therm/kWh
	Non-cogen Rate	1,344	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	2,736	$0.30375		
	Non-cogen Rate	2,736	$0.35185		

Steam Rate Schedule:		Hours/Yr	Energy ($/therm)
Summer	Marginal Rate	1,696	$0.222
Winter	Marginal Rate	2,384	$0.180
		4,080	

TABLE G.11. Energy Analysis for Scenario 11 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	0		$0	
	Non-cogen Rate	606,027		$221,939	
	sub-total	606,027		$221,939	
Summer	Cogen Rate	0		$0	
	Non-cogen Rate	1,233,698		$434,076	
	sub-total	1,233,698		$434,076	
Total		1,839,724		$656,016	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	2,217,530		3,080	
	Semi-Peak	2,851,110		3,080	
	Off-Peak	0			
Winter	On-Peak	1,335,897		3,080	
	Semi-Peak	5,788,888		3,080	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	2,189,811		3,042		$354,419	/yr
	Semi-Peak	2,815,471		3,042		$146,483	/yr
	Off-Peak	0				$0	/yr
	sub-total	5,005,281				$500,901	
Winter	On-Peak	1,319,199		3,042		$127,608	/yr
	Semi-Peak	5,716,527		3,042		$247,287	/yr
	Off-Peak	0				$0	/yr
	sub-total	7,035,726				$374,895	
Total		12,041,007				$875,796	

Thermal Energy Recoverable:	Summer		Winter		Total	
	333,466	therms/yr	468,740	therms/yr	802,205	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.11. Energy Analysis for Scenario 11 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	80,900	9,172	$17,990
Winter	109,232	12,385	$19,709
Total	190,132	21,557	$37,699

Summary of Calculations:

Natural Gas Fuel Cost	($656,016)	/yr
Electrical Savings	$875,796	/yr
SDG&E Back-up Cost	($36,590)	/yr
Thermal Savings	$37,699	/yr
Net Energy Savings	220,889	/yr

Average SDG&E/FERC Efficiency 30.56%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

TABLE G.12. Energy Analysis for Scenario 12

Gas Turbine Engine Data:

Number of Engines	2	Units operating		
Generator Capacity	1,540	kW-each		
Contracted Demand	3,080	kW @	$0.99	/kW-month (back-up)
Heat Rate (HHV)	14,620	Btu/kWh		
Thermal Recovery	45%	(percent of total energy)		

Operating Schedule:	Summer	Winter
On-Peak	Y	Y
Semi-Peak	N	N
Off-Peak	N	N

Available Operating Hours	8,760	h/yr
Scheduled Downtime	260	h/yr
Net Operating Hours	8,500	h/yr
Net Utilization of Hours	97%	
Load Utilization Factor	100%	(average engine load factor when in operation)
Powerhouse Load	1.25%	(percent of load used in powerhouse)

Electric Rate Schedule:		Hours/Yr	Energy ($/kWh)	Demand ($/kW)
Summer	On-Peak	742	$0.06886	$13.39
	Semi-Peak	0	$0.04533	$1.24
	Off-Peak	0	$0.03369	
	sub-total	742		
Winter	On-Peak	447	$0.06171	$2.17
	Semi-Peak	0	$0.03864	$1.24
	Off-Peak	0	$0.03186	
	sub-total	447		
	Total	1,189		

Natural Gas Rate Schedule:		Hours/Yr	Energy ($/therm)		
Winter	Cogen Rate	252	$0.30895	0.107	therm/kWh
	Non-cogen Rate	252	$0.36622	1,032	Btu/cuft HHV
				928.8	Btu/cuft LHV
Summer	Cogen Rate	937	$0.30375		
	Non-cogen Rate	937	$0.35185		

Steam Rate Schedule:			
Summer	Marginal Rate	742	$0.222
Winter	Marginal Rate	447	$0.180
		1,189	

TABLE G.12. Energy Analysis for Scenario 12 (contd)

Natural Gas Consumed:		Energy	(therms/yr)	Value	($/yr)
Winter	Cogen Rate	0		$0	
	Non-cogen Rate	113,630		$41,614	
	sub-total	113,630		$41,614	
Summer	Cogen Rate	0		$0	
	Non-cogen Rate	422,505		$148,659	
	sub-total	422,505		$148,659	
Total		536,135		$190,272	

Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)
Summer	On-Peak	2,217,530		3,080	
	Semi-Peak	0		0	
	Off-Peak	0			
Winter	On-Peak	1,335,897		3,080	
	Semi-Peak	0		0	
	Off-Peak	0			

Net Electricity Generated:		Energy	(kWh/yr)	Demand	(kW)	Value	($/yr)
Summer	On-Peak	2,189,811		3,042		$354,419	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	2,189,811				$354,419	
Winter	On-Peak	1,319,199		3,042		$127,608	
	Semi-Peak	0		0		$0	
	Off-Peak	0				$0	
	sub-total	1,319,199				$127,608	
Total		3,509,009				$482,027	

Thermal Energy Recoverable:	Summer		Winter		Total	
	145,891	therms/yr	87,889	therms/yr	233,780	therms/yr

Required Thermal Energy:		Summer	(therms/yr)	Winter	(therms/yr)	Total	(therms/yr)
	Cooling	176,330		234,460		410,790	
	Heating	0		0		0	
	Re-Heat	0		0		0	
	DHW	4,183		5,797		9,980	
	sub-total	180,513		240,257		420,770	

TABLE G.12. Energy Analysis for Scenario 12 (contd)

Thermal Energy Recoverable & Useable:

	Energy (therms/yr)	Steam (Mlbs/yr)	Value ($/yr)
Summer	35,394	4,013	$7,871
Winter	20,481	2,322	$3,695
Total	55,875	6,335	$11,566

Summary of Calculations:

Natural Gas Fuel Cost	($190,272)	/yr
Electrical Savings	$482,027	/yr
SDG&E Back-up Cost	($36,590)	/yr
Thermal Savings	$11,566	/yr
Net Energy Savings	266,731	/yr

Average SDG&E/FERC Efficiency 30.61%

42.5% or greater required for cogen gas rate

Does not qualify for cogen gas rate.

Appendix H

Permit to Operate

CONTROL NO.
65[illegible]

PERMIT TO OPERATE

EXPIRES
JANUARY 1, 1992

THIS PERMIT IS NOT VALID UNTIL REQUIRED FEES ARE RECEIVED BY THE DISTRICT.

THE FOLLOWING IS HEREBY GRANTED A PERMIT TO OPERATE THE ARTICLE, MACHINE, EQUIPMENT OR CONTRIVANCE DESCRIBED BELOW. THIS PERMIT IS NOT TRANSFERABLE TO A NEW OWNER, NOR IS IT VALID FOR OPERATION OF THE EQUIPMENT AT ANOTHER LOCATION, EXCEPT FOR PORTABLE EQUIPMENT.

860537
USN AIR STATION / NCRIS (2)PUB WKS
ENV/UTILITIES BR CODE 640
P O BOX 113 NAV STA PWC
SAN DIEGO CA 92136

EQUIPMENT ADDRESS

NAS NORTH ISLAND
SAN DIEGO CA 92135

EQUIPMENT DESCRIPTION

RENEWAL FEE $5,254.00

ONE(1) CATERPILLAR MODEL G 399 HCTA RICH BURN PISTON ENGINE(915 HP) DRIVING A 650KW ELECTRICAL GENERATOR WITH ONE(1) ENGELHARDDUAL STAGE CATALYTIC CONVERTER SET B-40612, SECOND STAGE AIR BLOWER SET, ENGELHARD AIR TO FUEL RATIO CONTROL, AND WASTE HEAT RECOVERY.-ENG. # 1 BLDG 1482 RLB/0688

BLDG 1482 860537
U 05343A 860537 0901L 34A01 92F01 92G01

IN ACCORDANCE WITH RULE 10C ATTACH THIS PERMIT TO YOUR CURRENT PERMIT WHICH INCLUDES THE OPERATING CONDITIONS OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT.

THIS AIR POLLUTION CONTROL DISTRICT PERMIT DOES NOT RELIEVE THE HOLDER FROM OBTAINING PERMITS OR AUTHORIZATIONS WHICH MAY BE REQUIRED BY OTHER GOVERNMENTAL AGENCIES.

R.J. Sommerville
AIR POLLUTION CONTROL OFFICER

1. ACCESS FACILITIES AND UTILITIES FOR SOURCE TESTING AS REQUIRED BY THE AIR POLLUTION CONTROL OFFICER SHALL BE PROVIDED WHEN SUCH TESTING IS PERFORMED BY THE DISTRICT.
2. THIS PERMIT, OR COPY THEREOF, INCLUDING THE PERMIT CONDITIONS, SHALL BE ATTACHED TO OR ACCOMPANY THE EQUIPMENT AT ALL TIMES.
3. OXIDES OF NITROGEN (NOX) EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 215 PARTS PER MILLION BY VOLUME (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PRECENT OXIGEN ON A DRY BASIS.
   CARBON MONOXIDE EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 350 PARTS PER MILLION (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PERCENT OXIGEN ON A DRY BASIS.
5. THE ENGELHARD AIR TO FUEL RATIO CONTROLLER SHALL BE INEPECTED EVERY 2000 HOURS FOR PROPER OPERATION. THE OXYGEN SENSORS SHALL BE REPLACED AT LEAST EVERY TWO (2) THOUSAND HOURS OF ENGINE OPERATION. RECORDS OF THE INSPECTION AND SENSOR REPLACEMENT DATES SHALL BE MAINTAINED AND MADE AVAILABLE TO THE DISTRICT UPON REQUEST.
6. EACH ENGINE / GENERATOR SET SHALL BE OPERATED AT A LOAD RATING OF 600 KW AND SHALL NOT BE OPERATED BELOW 550 KW ~~OR ABOVE 620 KW FOR ANY PERIOD IN~~ EXCESS OF ONE HOUR UNLESS APPROVED IN ADVANCE BY THE AIR POLLUTION CONTROL DISTRICT.
7. THE BYPASS VALVE ON EACH BLOWER THAT SUPPLIES ADDITIONAL AIR TO THE SECOND STAGE CATALYTIC CONVERTER SHALL BE MAINTAINED IN THE OPEN / CLOSED POSTION ESTABLISHED FOR THE INITIAL COMPLIANCE TEST. A LOCKING DEVICE SHALL BE AFFIXED TO THE VALVE TO SEAL THE VALVE IN THE APPROPRIATE POSITION.
8. OPERATION MUST BE IN COMPLIANCE WITH ALL INFORMATION INCLUDED IN APPLICATIONS FOR THIS PERMIT TO OPERATE AS APPROVED BY THE DISTRICT AND THE PERFORMANCE CONDITIONS LISTED ABOVE.

WITHIN 10 DAYS AFTER RECEIPT OF THIS PERMIT, THE APPLICANT MAY PETITION THE HEARING BOARD TO REVIEW ANY CONDITION THAT HAS BEEN MODIFIED OR ADDED TO THE PERMIT. (RULE 25 AND REGULATION VI)

IN ACCORDANCE WITH RULE 10C THIS PERMIT TO OPERATE OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT.

THIS AIR POLLUTION CONTROL DISTRICT PERMIT DOES NOT RELIEVE THE HOLDER FROM OBTAINING PERMITS OR AUTHORIZATIONS WHICH MAY BE REQUIRED BY OTHER GOVERNMENTAL AGENCIES.

R.J. Sommerville
AIR POLLUTION CONTROL OFFICER

15019
CONTROL NO.

(619) 694-3307

PERMIT TO OPERATE

860538
PED EXPIRES
JANUARY 1, 1992

THIS PERMIT IS NOT VALID UNTIL REQUIRED FEES ARE RECEIVED BY THE DISTRICT.

THE FOLLOWING IS HEREBY GRANTED A PERMIT TO OPERATE THE ARTICLE, MACHINE, EQUIPMENT OR CONTRIVANCE DESCRIBED BELOW. THIS PERMIT IS NOT TRANSFERABLE TO A NEW OWNER, NOR IS IT VALID FOR OPERATION OF THE EQUIPMENT AT ANOTHER LOCATION, EXCEPT FOR PORTABLE EQUIPMENT.

860538
USN AIR STATION / NORIS (2)PUB WKS
ENV/UTILITIES BR CODE 640
P O BOX 113 NAV STA PWC
SAN DIEGO CA 92136

EQUIPMENT ADDRESS

NAS NORTH ISLAND
SAN DIEGO CA 92135

EQUIPMENT DESCRIPTION

RENEWAL FEE $5,254.00

ONE(1) CATERPILLAR MODEL 0399 RICH BURN PISTON ENGINE(915 HP) DRIVING A 630KW ELECTRICAL GENERATOR WITH AN ENGELHARD DAUL STAGE CATALYTIC CONVERTER SET, SECOND STAGE BLOWER SET, ENGELHARD AUTOMATIC AIR TO FUEL RATIO CONTROL AND WASTE HEAT RECOVERY. -ENG. # 2
BLDG 1482

APP. #860538 RLB 6/23/88

U 05343A 860538 0901L 34A01 92F01 92901

860538

IN ACCORDANCE WITH RULE 10C ATTACH THIS PERMIT TO YOUR CURRENT PERMIT WHICH INCLUDES THE OPERATING CONDITIONS OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT.

THIS AIR POLLUTION CONTROL DISTRICT PERMIT DOES NOT RELIEVE THE HOLDER FROM OBTAINING PERMITS OR AUTHORIZATIONS WHICH MAY BE REQUIRED BY OTHER GOVERNMENTAL AGENCIES.

R.J. Sommerville
AIR POLLUTION CONTROL OFFICER

1. ACCESS FACILITIES AND UTILITIES FOR SOURCE TESTING AS REQUIRED BY THE AIR POLLUTION CONTROL OFFICER SHALL BE PROVIDED WHEN SUCH TESTING IS PERFORMED BY THE DISTRICT.
2. THIS PERMIT, OR COPY THEREOF, INCLUDING THE PERMIT CONDITIONS, SHALL BE ATTACHED TO OR ACCOMPANY THE EQUIPMENT AT ALL TIMES.
3. OXIDES OF NITROGEN (NOX) EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 215 PARTS PER MILLION BY VOLUME (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PRECENT OXIGEN ON A DRY BASIS.
   CARBON MONOXIDE EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 350 PARTS PER MILLION (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PERCENT OXIGEN ON A DRY BASIS.
5. THE ENGELHARD AIR TO FUEL RATIO CONTROLLER SHALL BE INSPECTED EVERY 2000 HOURS FOR PROPER OPERATION. THE OXYGEN SENSORS SHALL BE REPLACED AT LEAST EVERY TWO (2) THOUSAND HOURS OF ENGINE OPERATION. RECORDS OF THE INSPECTION AND SENSOR REPLACEMENT DATES SHALL BE MAINTAINED AND MADE AVAILABLE TO THE DISTRICT UPON REQUEST.
6. EACH ENGINE / GENERATOR SET SHALL BE OPERATED AT A LOAD RATING OF 600 KW AND SHALL NOT BE OPERATED BELOW 550 KW OR ABOVE 620 KW FOR ANY PERIOD IN EXCESS OF ONE HOUR UNLESS APPROVED IN ADVANCE BY THE AIR POLLUTION CONTROL DISTRICT.
7. THE BYPASS VALVE ON EACH BLOWER THAT SUPPLIES ADDITIONAL AIR TO THE SECOND STAGE CATALYTIC CONVERTER SHALL BE MAINTAINED IN THE OPEN / CLOSED POSTION ESTABLISHED FOR THE INITIAL COMPLIANCE TEST. A LOCKING DEVICE SHALL BE AFFIXED TO THE VALVE TO SEAL THE VALVE IN THE APPROPRIATE POSITION.
8. OPERATION MUST BE IN COMPLIANCE WITH ALL INFORMATION INCLUDED IN APPLICATIONS FOR THIS PERMIT TO OPERATE AS APPROVED BY THE DISTRICT AND THE PERFORMANCE CONDITIONS LISTED ABOVE.

WITHIN 10 DAYS AFTER RECEIPT OF THIS PERMIT, THE APPLICANT MAY PETITION THE HEARING BOARD TO REVIEW ANY CONDITION THAT HAS BEEN MODIFIED OR ADDED TO THE PERMIT. (RULE 25 AND REGULATION VI)

IN ACCORDANCE WITH RULE 10C THIS PERMIT TO OPERATE OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT.

R.J. Sommerville

CONTROL NO.

PERMIT TO OPERATE

860539

EXPIRES JANUARY 1, 1992

THIS PERMIT IS NOT VALID UNTIL REQUIRED FEES ARE RECEIVED BY THE DISTRICT.

THE FOLLOWING IS HEREBY GRANTED A PERMIT TO OPERATE THE ARTICLE, MACHINE, EQUIPMENT OR CONTRIVANCE DESCRIBED BELOW. THIS PERMIT IS NOT TRANSFERABLE TO A NEW OWNER, NOR IS IT VALID FOR OPERATION OF THE EQUIPMENT AT ANOTHER LOCATION, EXCEPT FOR PORTABLE EQUIPMENT.

860539
USN AIR STATION / NORIS (2)PUB WKS
ENV/UTILITIES BR CODE 640
P O BOX 113 NAV STA PWC
SAN DIEGO CA 92136

EQUIPMENT ADDRESS

NAS NORTH ISLAND
SAN DIEGO CA 92135

EQUIPMENT DESCRIPTION

RENEWAL FEE $5,254.00

ONE(1) CATERPILLAR MODEL G399 RICH BURN PISTON ENGINE DRIVING A 650KW ELECTRICAL GENERATOR WITH AN ENGELHARD DUAL STAGE CATALYTIC CONVERTER SET, SECOND STAGE BLOWER SET, ENGELHARD AUTOMATIC AIR TO FUEL RATIO CONTROL, AND WASTE HEAT RECOVERY. -ENG. # 3 APP. # 860539 RLB 6/23/88
BLDG 1482

860539

U 05343A 860539 0901L 34A01 92F01 92001

IN ACCORDANCE WITH RULE 10C ATTACH THIS PERMIT TO YOUR CURRENT PERMIT WHICH INCLUDES THE OPERATING CONDITIONS OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT

THIS AIR POLLUTION CONTROL DISTRICT PERMIT DOES NOT RELIEVE THE HOLDER FROM OBTAINING PERMITS OR AUTHORIZATIONS WHICH MAY BE REQUIRED BY OTHER GOVERNMENTAL AGENCIES.

R.J. Sommerville
AIR POLLUTION CONTROL OFFICER

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2. THIS PERMIT, OR COPY THEREOF, INCLUDING THE PERMIT CONDITIONS, SHALL BE ATTACHED TO OR ACCOMPANY THE EQUIPMENT AT ALL TIMES.
3. OXIDES OF NITROGEN (NOX) EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 215 PARTS PER MILLION BY VOLUME (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PRECENT OXIGEN ON A DRY BASIS.
   CARBON MONOXIDE EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 350 PARTS PER MILLION (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PERCENT OXIGEN ON A DRY BASIS.
5. THE ENGELHARD AIR TO FUEL RATIO CONTROLLER SHALL BE INSPECTED EVERY 2000 HOURS FOR PROPER OPERATION. THE OXYGEN SENSORS SHALL BE REPLACED AT LEAST EVERY TWO (2) THOUSAND HOURS OF ENGINE OPERATION. RECORDS OF THE INSPECTION AND SENSOR REPLACEMENT DATES SHALL BE MAINTAINED AND MADE AVAILABLE TO THE DISTRICT UPON REQUEST.
6. EACH ENGINE / GENERATOR SET SHALL BE ~~OPERATED AT A LOAD RATING OF 600 KW~~ AND SHALL NOT BE OPERATED BELOW 580 KW OR ABOVE 620 KW FOR ANY PERIOD IN EXCESS OF ONE HOUR UNLESS APPROVED IN ADVANCE BY THE AIR POLLUTION CONTROL DISTRICT.
7. THE BYPASS VALVE ON EACH BLOWER THAT SUPPLIES ADDITIONAL AIR TO THE SECOND STAGE CATALYTIC CONVERTER SHALL BE MAINTAINED IN THE OPEN / CLOSED POSTION ESTABLISHED FOR THE INITIAL COMPLIANCE TEST. A LOCKING DEVICE SHALL BE AFFIXED TO THE VALVE TO SEAL THE VALVE IN THE APPROPRIATE POSITION.
8. OPERATION MUST BE IN COMPLIANCE WITH ALL INFORMATION INCLUDED IN APPLICATIONS FOR THIS PERMIT TO OPERATE AS APPROVED BY THE DISTRICT AND THE PERFORMANCE CONDITIONS LISTED ABOVE.

EXPIRES

WITHIN 10 DAYS AFTER RECEIPT OF THIS PERMIT, THE APPLICANT MAY PETITION THE HEARING BOARD TO REVIEW ANY CONDITION THAT HAS BEEN MODIFIED OR ADDED TO THE PERMIT. (RULE 25 AND REGULATION VI)

IN ACCORDANCE WITH RULE 10C THIS PERMIT TO OPERATE OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN

CONTROL NO.
55721

PERMIT TO OPERATE

860540
EXPIRES
JANUARY 1, 1992

THIS PERMIT IS NOT VALID UNTIL REQUIRED FEES ARE RECEIVED BY THE DISTRICT.

THE FOLLOWING IS HEREBY GRANTED A PERMIT TO OPERATE THE ARTICLE, MACHINE, EQUIPMENT OR CONTRIVANCE DESCRIBED BELOW. THIS PERMIT IS NOT TRANSFERABLE TO A NEW OWNER, NOR IS IT VALID FOR OPERATION OF THE EQUIPMENT AT ANOTHER LOCATION, EXCEPT FOR PORTABLE EQUIPMENT.

860540
USN AIR STATION / NORIS (2)PUB WKS
ENV/UTILITIES BR CODE 640
P O BOX 113 NAV STA PWC
SAN DIEGO CA 92136

EQUIPMENT ADDRESS

NAS NORTH ISLAND
SAN DIEGO CA 92135

EQUIPMENT DESCRIPTION

RENEWAL FEE $5,254.00

ONE(1) CATERPILLAR MODEL G399 RICH BURN PISTON ENGINE DRIVING A 650KW ELECTRIC GENERATOR WITH AN ENGELHARD DUAL STAGE CATALYTIC CONVERTER SET, SECOND STAGE BLOWER SET, ENGELHARD AUTOMATIC AIR TO FUEL RATIO CONTROL, AND WASTE HEAT RECOVERY. -ENG. # 4
BLDG 1482

APP. # 860540 RLB 6/23/88

U 05343A 860540 0901L 34A01 92F01 92G01

860540

IN ACCORDANCE WITH RULE 10C ATTACH THIS PERMIT TO YOUR CURRENT PERMIT WHICH INCLUDES THE OPERATING CONDITIONS OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN FULL FORCE AND EFFECT UNLESS EXPRESSLY MODIFIED BY THE AIR POLLUTION CONTROL DISTRICT.

THIS AIR POLLUTION CONTROL DISTRICT PERMIT DOES NOT RELIEVE THE HOLDER FROM OBTAINING PERMITS OR AUTHORIZATIONS WHICH MAY BE REQUIRED BY OTHER GOVERNMENTAL AGENCIES.

R.J. Sommerville
AIR POLLUTION CONTROL OFFICER

1. ACCESS FACILITIES AND UTILITIES FOR SOURCE TESTING AS REQUIRED BY THE AIR POLLUTION CONTROL OFFICER SHALL BE PROVIDED WHEN SUCH TESTING IS PERFORMED BY THE DISTRICT.
2. THIS PERMIT, OR COPY THEREOF, INCLUDING THE PERMIT CONDITIONS, SHALL BE ATTACHED TO OR ACCOMPANY THE EQUIPMENT AT ALL TIMES.
3. OXIDES OF NITROGEN (NOX) EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 215 PARTS PER MILLION BY VOLUME (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PRECENT OXIGEN ON A DRY BASIS.
   CARBON MONOXIDE EMISSIONS FROM THE ENGINE SHALL NOT EXCEED 350 PARTS PER MILLION (PPMV) MEASURED IN THE FLUE GAS AND CALCULATED AT THREE (3) PERCENT OXIGEN ON A DRY BASIS.
5. THE ENGELHARD AIR TO FUEL RATIO CONTROLLER SHALL BE INSPECTED EVERY 2000 HOURS FOR PROPER OPERATION. THE OXYGEN SENSORS SHALL BE REPLACED AT LEAST EVERY TWO (2) THOUSAND HOURS OF ENGINE OPERATION. RECORDS OF THE INSPECTION AND SENSOR REPLACEMENT DATES SHALL BE MAINTAINED AND MADE AVAILABLE TO THE DISTRICT UPON REQUEST.
6. EACH ENGINE / GENERATOR SET SHALL ~~BE OPERATED AT A LOAD RATING OF 600 KW~~ AND SHALL NOT BE OPERATED BELOW 580 KW OR ABOVE 620 KW FOR ANY PERIOD IN EXCESS OF ONE HOUR UNLESS APPROVED IN ADVANCE BY THE AIR POLLUTION CONTROL DISTRICT.
7. THE BYPASS VALVE ON EACH BLOWER THAT SUPPLIES ADDITIONAL AIR TO THE SECOND STAGE CATALYTIC CONVERTER SHALL BE MAINTAINED IN THE OPEN / CLOSED POSTION ESTABLISHED FOR THE INITIAL COMPLIANCE TEST. A LOCKING DEVICE SHALL BE AFFIXED TO THE VALVE TO SEAL THE VALVE IN THE APPROPRIATE POSITION.
8. OPERATION MUST BE IN COMPLIANCE WITH ALL INFORMATION INCLUDED IN APPLICATIONS FOR THIS PERMIT TO OPERATE AS APPROVED BY THE DISTRICT AND THE PERFORMANCE CONDITIONS LISTED ABOVE.

EXPIRED

THIN 10 DAYS AFTER RECEIPT OF THIS PERMIT, THE APPLICANT MAY PETITION THE HEARING BOARD TO REVIEW ANY CONDITION THAT HAS BEEN MODIFIED OR ADDED TO THE PERMIT. (RULE 25 AND REGULATION VI)

IN ACCORDANCE WITH RULE 10C THIS PERMIT TO OPERATE OR A COPY MUST BE POSTED ON OR WITHIN 25 FEET OF THE EQUIPMENT, OR MAINTAINED READILY AVAILABLE AT ALL TIMES ON THE OPERATING PREMISES.

ANY AND ALL CONDITIONS WHICH HAVE BEEN APPLIED TO THIS EQUIPMENT SHALL REMAIN IN

Appendix I

Energy Technology Engineering Center Report

Energy Technology Engineering Center
Rocketdyne Division
Rockwell International Corporation
P.O. Box 7930
Canoga Park, California 91309

(818) 710-6300

Operator for
U.S. Department of Energy

26 March 1993

In reply refer to 93ETEC-DRF 0536

Mr. Steven A. Parker
Senior Research Engineer
Battelle
Pacific Northwest Laboratories
Battelle Boulevard
P. O. Box 999
Richland, Washington 99352

Subject: Evaluation of MCTS NASNI Cogeneration Plant

Dear Mr. Parker:

The subject evaluation has been completed (enclosure). The Naval Computer & Telecommunications Station (NCTS) at Naval Air Station North Island (NASNI), San Diego, CA was site-visited on 1-2 March 1993. Various persons from the Navy Public Works Center were interviewed, including the following:

Norman Groth, Cogeneration Department Head
Richard Imel, Foreman
John Thomas, Manager

I also interviewed Robert Winn, P. E. Executive Vice President, Pentech Services, Inc. All four cogen units in Building 1482 were inspected, the Unscheduled Repair Log Book, Job Orders, and Engine Maintenance Contract (with Pentech) were reviewed. The San Diego Gas & Electric's various rate schedules were also obtained.

Telephone calls were also made and included the following:

1. Woodward Governor Co.
   Fort Collins, Colorado
2. Gerhardt's Inc.
   Ventura, California
3. Mechanical Equipment, Inc.
   Midland, Texas
4. Caterpillar, Inc.
   Peoria, Illinois
5. Hawthorne Power Systems
   San Diego, California
6. Pentech Services, Inc.
   San Diego, California

The evaluation includes the past year's Unscheduled Repair Log Book and Job Orders information (Table 1). It also includes the various rate schedules of SDG&E and the persons telephoned with addresses and phone numbers (Table 2).

If you have any questions, or if we can be of further assistance, please call me at (818) 586-5510.

Sincerely,

ROCKWELL INTERNATIONAL CORPORATION
Rocketdyne Division

Robert K. Hoshide, CEM, CLEP
Project Manager, Energy Management
Energy Technology Engineering Center

D030-0038/bs

Enclosures as noted

cc w/o enclosures: R. LeChevalier, DOE, ETEC Site Mgr

Table 1

UNSCHEDULED REPAIR LOG
PENTEC SERVICES, INC.

Date	*Unit No.*	*Description*
10/03/91	2	Brazed water line on water pump inlet.
10/04/91	4	Synchro Switch (overspeed switch) checked out & parts ordered.
10/08/91	3	Synchro start overspeed switch installed.
11/26/91	2	Replaced La Marche battery charger.
02/21/92	4	Swapped load controller from Unit No. 2.
02/22/92	3	AFRC would not control flowrate nor read proper milivolts from O_2 sensor used No. 2 AFRC. Hard time getting controller as part was discontinued.
03/19/92	4	Helped checkout load controller (2301).
04/01/92	4	Engine would not operate at proper speed. Found short in wiring, governor O.K. Kato Generator: smoke & coming apart internally.
04/10/92	3	Engine would not start, used No. 4 batteries then replaced No. 4 batteries.
05/20/92	1	Broken exhaust valve in No. 14 cylinder. Rebuilt engine.
06/23/92	2	Water pump leaking.
08/20/92	3	Power supply in AFRC burned-up. Used No. 4 & repaired control board & installed in No. 4.
08/20/92	2	Blown battery, used No. 4 battery.
08/21/92	3	Low oil pressure, switch & magnetic pickup not working. Both replaced.
09/08/92	1	Load controller (2301) burned-up.
09/09/92	1	Replaced load controller with 2301A.
09/11/92	1	Engine would not run. Broken magento drive.
09/22/92	4	After rebuilding left carburetor engine shutdown during testing. The Murphy vibration switch burned.
09/25/92	4	Safety switch installed.
09/29/92	2	Can't control engine speed & could not load. Found short in wiring from magnetic pickup. Replaced wiring.
10/22/92	4	AFRC circuit board pulled from No. 3. Board repaired & installed in No. 3.
11/04/92	4	Magneto, engine running erratically. Pulled No. 3 magento, installed factory rebuilt magneto on No. 3.
02/11/92	3	Engine running erratically, switched No. 2 load controller & replaced O_2 sensor.
12/15/92	2	Replaced water line & seals to aftercooler.

Table 1 (Continued)

JOB ORDERS
PENTEC SERVICES, INC.

Date	*Unit No.*	*Description*
10/23/91	3 & 4	Repair / Replace speed switches.
10/24/91	2	Repair / Replace battery charger.
02/24/92	3	Generator trip on reserve power & engine speed varying too much to load.
04/02/92	4	Throttle control, no electrical control of engine speed from switchboard.
04/02/92	4	Repaired throttle control valve.
04/15/92	3	Troubleshoot, engine will not crank enough to start.
06/24/92	2	Fix leaking water jacket pump.
11/09/92	4	AFRC is erratic in operation.
12/10/92	2	Repair / Adjust cooling water ling.
12/16/92	3	Repair / Adjust engine without overexhausting & tripping off-line.

08dg114.tbl

TABLE 2. CONTACTS FOR TECHNICAL INFORMATION

1. Navy Public Works Center
   P .O. Box 368113
   2730 McKean St., Ste 1
   San Diego, CA 92136-5294

Richard Imel	(619) 545-8615
Norman Groth	(619) 556-7988
John Thomas	(619) 556-7989

2. Woodward Governor Co.
   P. O. Box 1519
   Fort Collins, CO 80522

Wade Edgar	(303) 482-5811

3. Gerhardt's, Inc.
   2001 Palma Drive
   Ventura, CA 93003

James Wimp	(805) 658-2877

4. Mechanical Equipment, Inc.
   P. O. Box 1800
   Midland, TX 79702

Thomas Smith	(915) 687-0601

5. Caterpillar, Inc.
   100 N.E. Adams
   Peoria, IL 61629

Ken Smith	(309) 578-8117

6. Hawthorne Power Systems
   8050 Othello Avenue
   San Diego, CA 92111

Donald Lind	(619) 974-6885

7. Pentech Services, Inc.
   9740 Scranton Road, Suite 150
   San Diego, CA 92121

Robert M. Winn	(619) 457-2911

EVALUATION OF COGENERATION PLANT

Naval Computer & Telecommunication Center (NCTS)
Naval Air Station North Island (NASNI)
San Diego, California

Work Scope

Task A Identification of Repair/Replacement Requirements of Existing System

Identify repair and replacement requirements necessary, with associated costs, to bring the existing cogeneration plant, engines and controls, up to an acceptable level of reliability, as intended in the original plant's design, such that up to all 4 engines can be maintained on-line for scenarios:

4. continuous operation
5. operate on-peak and semi-peak; back-up status off-peak
6. operate on-peak, back-up status off-peak and semi-peak

Task B Identification of Modification Requirements to Convert the Cogeneration Plant to Emergency Generator Status

Identify repair, replacement, and modification requirements necessary, with associated costs to convert the existing cogeneration plant, engine and controls, to a reliable emergency generator system for scenarios;

13. back-up generator status, providing both electrical and thermal back-up
14. back-up generator status, install boiler for thermal back-up

Task A Engineering Estimates

Repair/Replacement requirements for the existing system include the following components:

1. Replace the 2301 Load Sharing & Speed Control, P/N 8271-706E-E with 2301A, P/N 9905020

   Estimated Cost:

Material:	$1,200/unit X 4	=	$4,800
Labor:	40 hr total @ $75/hr	=	3,000
Travel & subsistence:	$125/day X 5 days	=	625
			$8,425

2. Replace Engelhard Air Fuel Ratio Controller (AFRC), Series 2SG

   Estimated Cost:

Material:	$6,575/unit X 4	=	$26,300
Labor:	64 hr total @ $75/hr	=	4,800
(includes commissioning of first unit)			$31,100

3. Service and Tune-Up Woodward Governor Actuator, Model No. EG-3P, P/N E8250-553, Caterpillar Engine, Switch Gear & Rewire Electrical and Instrumentation

   Estimated Cost:

Wiring & misc. materials:	$1,500/unit X 4	=	$6,000
Labor:	10 hr total at $75/hr	=	9,000
	Total	=	$15,000

Total Cost = $8,425 + $31,100 + $15,000 = $54,525

In order to determine operation and maintenance requirements of the cogen units, the following information is supplied:

Caterpillar Engine, Natural Gas Fueled. Model G399TA, Rich Burn
Rated at 650 kW
Output: 600 kW

Engine No.	Serial No.	Total Run Time, hr (Through Mid-March, 1993)
1	49C01426	21,025
2	49C01428	23,724
3	49C01429	21,985
4	49C01427	21,564

Scenario No. 4. Continuous
24 hr/day X 365 days/yr = 8,760 hr/yr

Scenario No. 5. On- & Semi-Peak
Summer & winter hours: 6 a.m. to 10 p.m. = 16 hr
plus 1/2 hr lead & 1/4 hr lag
= 16.75 hr/day

Summer & winter days = 110 - 3 + 150 - 5 = 252
Total = 252 X 16.75 = 4,221 hr/yr
% of year = (4221/8760) 100 = 48.2%

Scenario No. 6. On-Peak

Summer hours: 11 a.m. to 6 p.m. = 7 + .75 = 7.75 hr/day

Hours/year = 107 X 7.75 = 829

Winter hours: 5 p.m. to 8 p.m. = 3 + .75 = 3.75 hr/day

Hours/year = 145 x 3.75 = 544

Total = 1373 hr/yr

% of year = (1373/8760) 100 = 15.7%

The present maintenance contract (N68711-90-D-8335) with Pentech Services, Inc. is summarized below (Table 3).

Code	Item	Cost
0005	Preventive Maint. (P.M.) cost/mo	$7,683
0006	Unscheduled maint. & service calls, cost/yr	9,600
0007	Major scheduled overhaul (every 30,000 hr)	30,376
0008	Materials, cost/yr	50,000
Added	Top-end overhaul (every 10,000 hr)	10,000

Costs for Codes 0005, 0006, and 0007 escalate as follows:

Code	2nd year	3rd year
0005	4.75%	4.83%
0006	3.75%	4.22%
0007	3.75%	3.78%

The estimated maintenance costs are as follows:

Scenario	Maintenance Cost
4	Same as present cost
5	48.2% + 20% = 68.2% of present cost
6	15.7% + 30% = 45.7% of present cost

The Navy Public Works Centers (NPWC) Operation and Maintenance staff can also be reduced for Scenarios 5 and 6. This estimate is as follows:

Scenario	NPWC Staff Reduction
4	No change
5	30% reduction
6	50% reduction

Task B

The estimated cost to convert the existing cogen plant is as follows:

1. Cost of Task A = $54,525
2. Conversion of controls to backup (emergency) generator system and servicing/checkout of existing switchgear and breakers is approximately $10,000.

Scenarios 13 and 14 Back-up Gene. ıtor Status

1. Operational Check With Load:

   Once a month for 2 hr
   2 hr/mon X 12 mon/yr = 24 hr/yr

2. Operational Check Without Load:

   Once a week for 1 hr, less 1 week per month (with load check).
   1 hr/week X 40 wk/yr = 40 hr/yr

3. Estimated Run Time per Year = 100 hr/yr

   Total = 24 + 40 + 100 = 162 hr/yr
   % of year = (162/8760) 100 = 2%

General Notes:

1. The estimated total useful life for each unit is 120,000 hr. The remaining useful life (with proper operation and maintenance) would still be almost 100,000 hr for all 4 units.
2. Their salvage value is presently estimated at $50,000 each.
3. Building 1482, NCTS presently uses the thermal energy from only cogen 2 units for their absorption units. Any additional heat would have to be disposed using their cooling towers.

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