ESL-TR-85/08-01

Cogeneration System Analysis

Summary Reports

for

Austin State Hospital
Capital Complex
San Antonio State Mental Hospital
Steven F. Austin University
Southwest Texas State University
Texas Woman's University
Texas Woman's University and North Texas State University
University of Houston-University Park
University of Texas at Dallas
University of Texas at El Paso
University of Texas at San Antonio

written for

The Public Utility Commission
Energy Efficiency Division

by

Energy Management Group
Department of Mechanical Engineering
Texas A&M University

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August 31, 1985

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August 31, 1985

SUMMARY REPORT

Cogeneration Analysis for Austin State Hospital

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. Austin State Hospital (ASH) was one of those sites, and it was selected for a detailed feasibility study. The hospital has a high thermal energy to electrical power requirement, which makes cogeneration especially attractive. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared with that of approximately 35 percent for a conventional power plant.

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost for natural gas, electricity, and operating and maintenance for the boilers.

Method of Analysis

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

Most of the input information required for the analysis was obtained from the ASH physical plant personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. ASH is currently paying $5.50/MCF for natural gas and the cost of electricity averages 7.12¢/kwh.

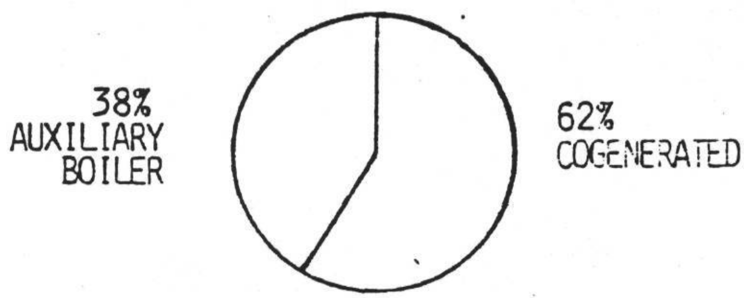
Assumptions

It was assumed that no electricity would be sold by ASH. The cogeneration system would therefore be a base load system. It was also assumed that a standby power charge of $5.16/kW of peak demand would be levied each month by the utility company, or that no standby charge would apply. This assumption is based on how other utilities' charges for standby power. Standby power is the electrical capacity that the utility must have in the event the cogeneration plant has an unscheduled down-time.

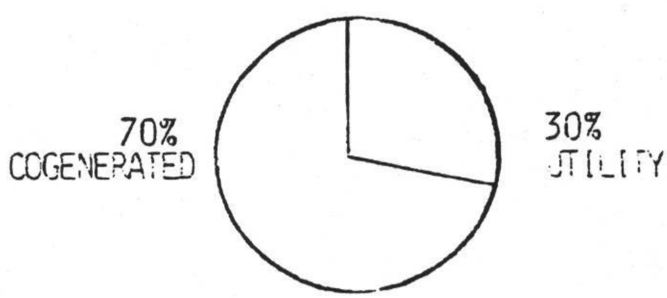
The hospital will purchase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum system for ASH was found to be a 1.0 MW (megawatt) gas turbine with a heat recovery steam generator, although the most economical size is relatively insensitive to small capacity variations between 0.5 MW and 1.3 MW. For at least one scenario of fuel price escalation, a larger size (1.3 MW) would be preferred based upon this analysis, if no standby power charges occurred. The gas turbine system could be installed at one of various sites at the hospital. The installed cost would be approximately \$1100/kW or about \$1,100,000. The electricity generated by the cogeneration system will cost about 8.1¢ /kwh (including operating and maintenance cost) which is only slightly higher than the purchase price. Therefore, the steam produced by the cogeneration system is almost "free." This gas turbine cogeneration system will save approximately \$240,000/yr and have a simple payback of 4.6 years. However, if the standby charge was relaxed, the cogeneration system would save about \$300,000/yr and have a simple payback of 3.6. years. The system will provide 62% of the annual thermal energy requirements and 70% of the annual electrical energy requirements, as shown on the charts.

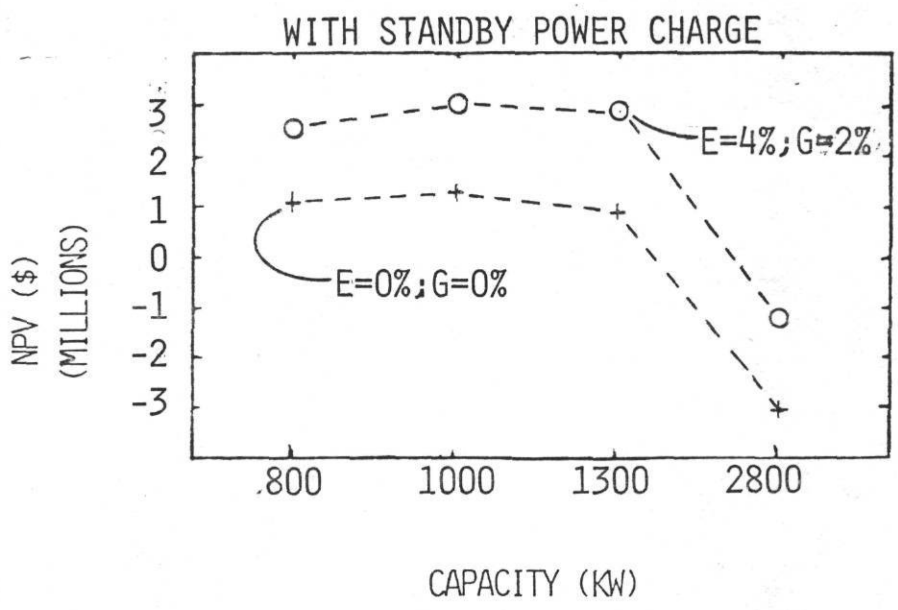


ANNUAL THERMAL ENERGY
REQUIREMENTS

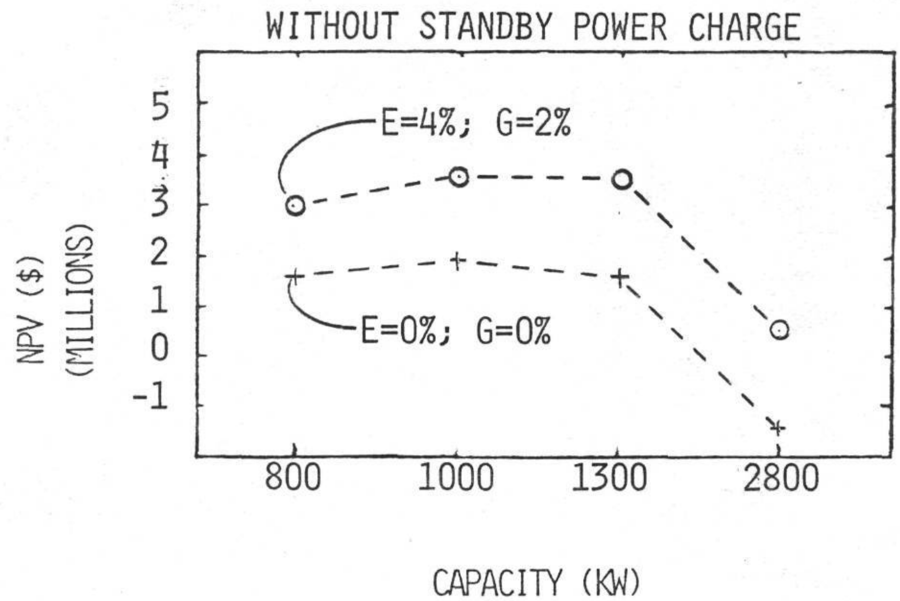


ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

A net present value (NPV) analysis is perhaps the best indicator of the potential savings from the cogeneration system. It projects the NPV including the cost of the cogeneration system over the lifetime of 20 years and gives the NPV of the system in today's dollars. NPV analyses were performed for the case using the current standby power charge and for the case using no standby charge. The adjacent graphs show the NPV for four sizes of gas turbines. With no fuel or electricity cost escalation above inflation, the 1.0 MW (1000kW) system shows an NPV from 1.0 million dollars to 1.8 million dollars depending on the standby charge. The other curve shown in each graph is for the case when the escalation rates for electricity and natural gas are 4 percent and 2 percent, respectively. If this scenario was to become a reality, the 1.0 MW cogeneration system would have an NPV from 3.0 million dollars to over 3.6 million dollars, again, depending on the standby charge.



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE

The $1100 per installed KW presumes that a small, auxiliary building will have to be constructed to house the gas turbine, generator, waste heat boiler, and switchgear. The building will be adjacent to the existing physical plant, but it will not be necessary to lay additional steamlines to tie into the curent facilities. Also, about one hundred feet of electrical lines will have to be constructed to tie into the electrical substation for the ASH faciity. These additional construction costs have added to the installed costs of the cogeneration facility.

Recommendations

A 1.0 MW gas turbine cogeneration system should be installed at ASH. The system would save the State of Texas from $240,000/yr to over $300,000/yr depending on the agreement arranged between the utility company and ASH concerning the standby power charge.

Cogeneration System Analysis

for

Capitol Complex
Austin, Texas

for

Public Utility Commission
Energy Efficiency Division

by

Energy Management Group
Department of Mechanical Engineering
Texas A&M University

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August 31, 1985

SUMMARY REPORT

Cogeneration Analysis for Capitol Complex

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. The Capitol Complex (CC) was one of those sites, and it was selected for a detailed feasibility study. The complex has a low thermal energy to electrical power requirement, which reduces the feasibility of cogeneration. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared with that of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance cost of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

Most of the input information required for the analysis was obtained from the CC Physical Plant personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. CC is currently paying $5.20 /MCF for natural gas and an average of 6.50¢/kwh for electricity.

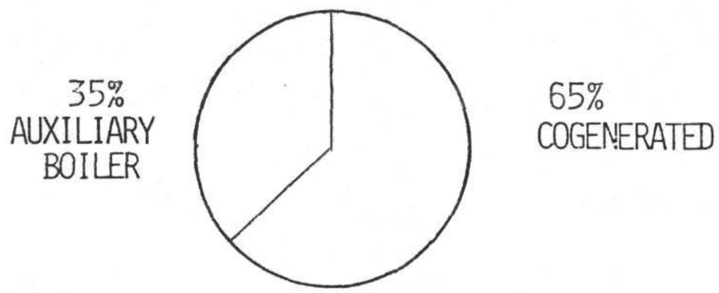
Assumptions

It was assumed that no electricity would be sold by CC. The cogeneration system would therefore be a base load system. It was also assumed that a standby power charge of $3.63/KW of peak demand (ratchet demand charge) would be levied each month by the utility company. This assumption is based on how other utilities charge for standby power. Standby power is the electrical capacity that the utility must have in the event that the cogeneration plant has an unscheduled down-time.

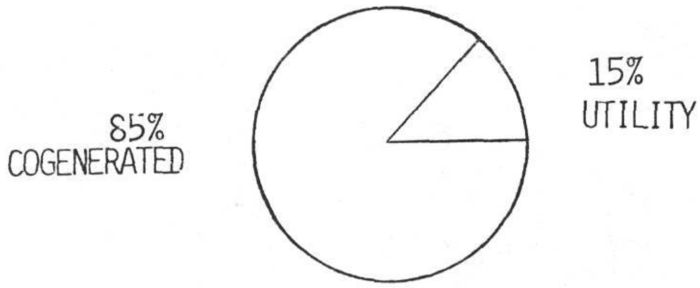
The complex would purchase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum system for CC was found to be a 2.5MW (megawatt) diesel engine with a heat recovery steam generator. The diesel engine system would be installed at one of the various sites on the complex. The installed cost would be approximately \$800/kW or about \$2,000,000. The electricity generated by the cogeneration system would cost about 5.84¢/kwh (including operating and maintenance cost) which is slightly lower than the purchase price. Therefore,the steam produced by the cogeneration system would be essentially "free." This diesel engine cogeneration system would save approximately \$225,000/yr and have a simple payback of 7.8 years. However, if the standby charge was relaxed, the cogeneration system would save \$364,000/yr and have a simple payback 5.5 years. The system would provide 65% of the annual thermal energy requirements and 85% of the annual electrical energy requirements, as shown on the charts.

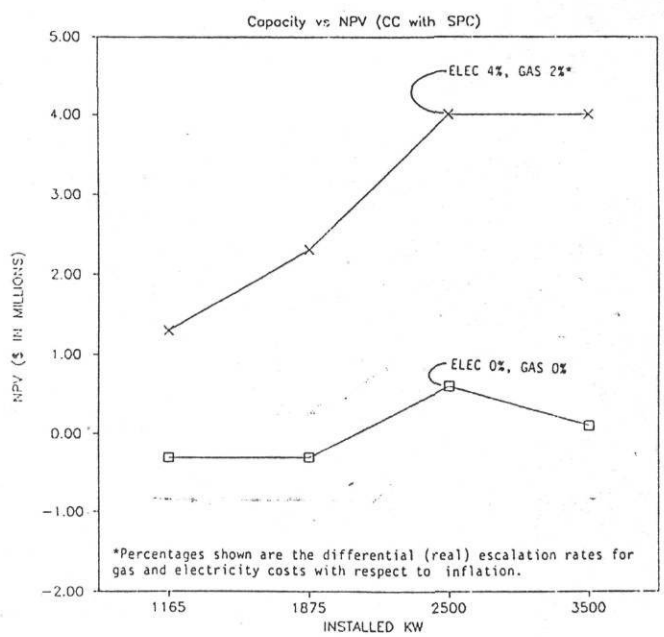


SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS

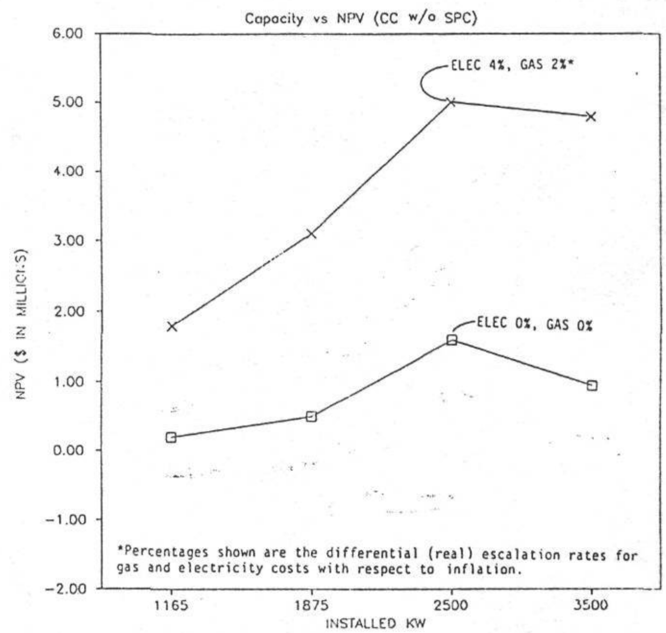


SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

A net present value (NPV) analysis is a good indicator of the potential savings from the cogeneration system. It projects the present value of the cogeneration system over its lifetime (20 years) and gives the NPV of the system in today's dollars. NPV analyses were performed for the case using the current standby power charge and for the case using no standby charge (no ratchet charge). The adjacent graphs show the NPV for four sizes of diesel engines. With no fuel or electricity cost escalation above inflation, the 2.5 MW (2500 KW) system shows an NPV from 0.5 million dollars to 1.6 million dollars depending on the standby charge. The other curve shown in each graph is for the case when the escalation rates for electricity and natural gas are 4 percent and 2 percent, respectively. If this scenario was to become a reality, the 2.5MW cogeneration system would have an NPV from 4 million dollars to over 5 million dollars, again, depending on the standby charge.



NPV vs. Installed Capacity for Diesel Engine Cogeneration Systems
Standby Power Charge Case



NPV vs. Installed Capacity for Diesel Engine Cogeneration Systems
No Standby Power Charge Case

Recommendations

A 2.5 MW diesel engine cogeneration system should be installed at CC. The system would save the State of Texas from $225,000/yr to over $360,000/yr depending on the agreement arranged between the utility company and CC concerning the standby power charges.

Cogeneration System Analysis

for

San Antonio State Mental Hospital

San Antonio, Texas

for

Public Utility Commission

Energy Efficiency Division

by

Energy Management Group

Department of Mechanical Engineering

Texas A&M University

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August 31, 1985

Cogeneration Analysis for San Antonio State School, Hospital

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential condidates for cogeneration among state agencies. After a detailed study it was concluded that a single cogeneration set-up would be adequate to meet the energy demands of the San Antonio State School, San Antonio State Chest Hospital and San Antonio State Hospital. The moderately high price paid by the institutions for electricity makes cogeneration attractive. The cogeneration system will generate electricity cheaper than the electricity purchased from the utility. In addition, dollar savings will be obtained from the "free" thermal energy obtained from the waste heat of the diesel engine. The overall thermal efficiency of a cogeneration system ranges from 70 to 85 percent. This is compared to an efficiency of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

The prices of electricity and natural gas purchased by institutions used in the analysis were $4.68/MCF for natural gas and 6.8¢/KWH for electricity. Economic analyses were made of the systems both with and without a standby power charge of $5.00/KW included.

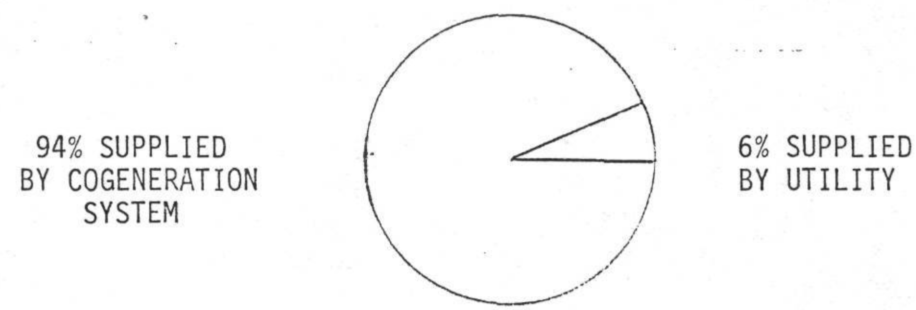
A diesel-driven cogeneration system was found to be the most appropriate to meet the campus electrical and thermal energy demand.

Assumptions

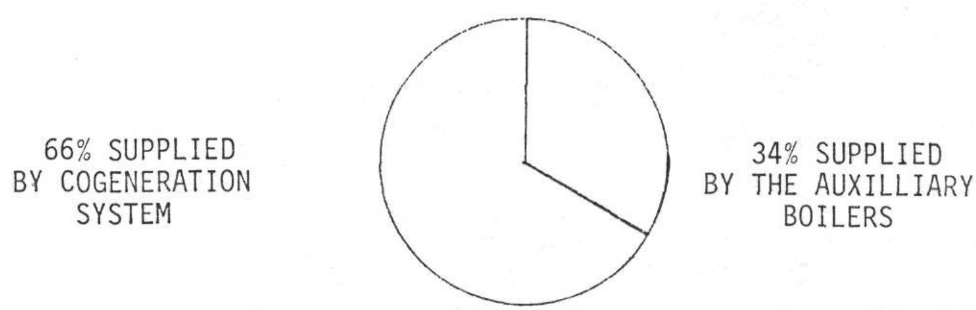
An installation cost of $800/KW was assumed for the system. This includes construction costs of the building housing the system, the diesel engine, the waste heat boiler, and the necessary electrical gear. Operation and maintenance costs for the diesel cogenerator were assumed to be $6.00/MWH. O&M costs for the thermal energy were assumed to be $1.10/KLB of steam generated in the auxiliary-fired boilers and $1.00/KLB of steam generated in the waste heat recovery boilers. It was assumed that no electricity would be sold. The cogeneration system is expected to have a lifetime of 20 years. Long term bond interest was assumed to be 8% in the NPV analysis.

Findings

Based on the above assumptions, the optimum system was found to be a 2.5 MW diesel engine. The cost of displaced electricity averaged 4.69¢/KWH. The installed cost would be approximately $1.9 million and would have a simple payback betweem 5.0 and 7.9 years. At current utility prices, the cogeneration system would save more than $400,000/year. The following figures graphically show the breakdown of generated and purchased utilities. This system would supply approximately 94% of the electrical load and 66% of the thermal energy requirements at SASH.



ANNUAL ELECTRICAL REQUIREMENTS

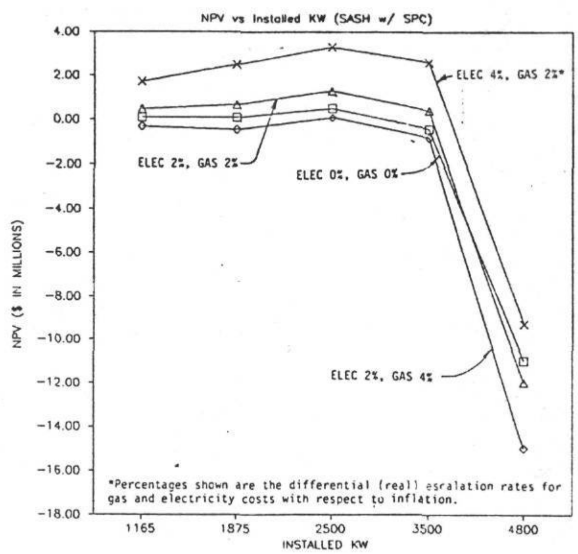


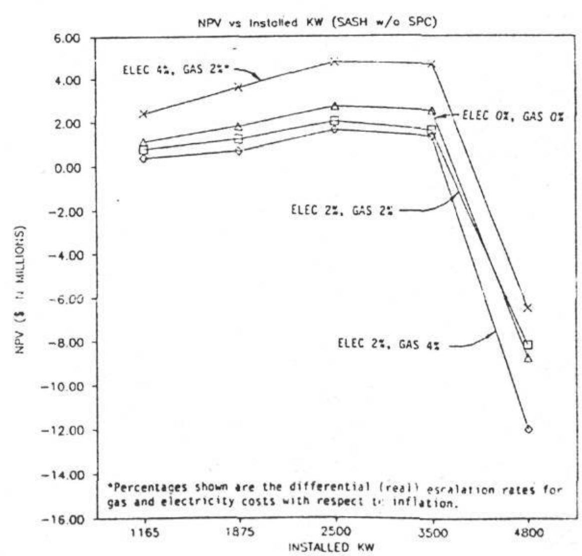
ANNUAL THERMAL ENERGY REQUIREMENTS

A net present value (NPV) analysis is perhaps the best indicator of the potential savings from the cogeneration system. It projects the savings over the lifetime (20 years) and gives the net value of the system in today's dollars. The adjacent figures show the NPV for five different diesel engine sizes. With no standby power charge, the NPV of the 2.5 MW system ranges from $1.6 million to $4.8 million depending on the escalation rate scenario. With the $5.00/KW standby power charge included, the NPV of the system ranges from $130,000 to over $3.3 million.

Recommendations

A 2.5 MW cogeneration system should be installed for meeting the energy demand of the three institutions. The system will save the State of Texas approximately $400,000 in reduced utility bills.





Cogeneration System Analysis

for

Stephen F. Austin University

Nacogdoches, Texas

for

Public Utility Commission

Energy Efficiency Division

by

Energy Management Group

Department of Mechanical Engineering

Texas A&M University

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Alan Propp

August 31, 1985

Summary Report for Stephen F. Austin University

Background

Cogeneration is defined as the generation of electrical power and coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the PUC identified 20 potential cogeneration candidates among state agencies. The Stephen F. Austin campus was one of those sites and it was selected for a detailed feasibility study. The campus has a low thermal energy to electrical power requirement which reduces the feasibility of cogeneration. The overall thermal efficiency of cogeneration system ranges from 70 to 85%. This is compared to an efficiency of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly thermal loads and electrical loads were required to determine the optimum cogeneration system. Other information required by CELCAP was cost data on natural gas, electricity, and the operation and maintenance of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

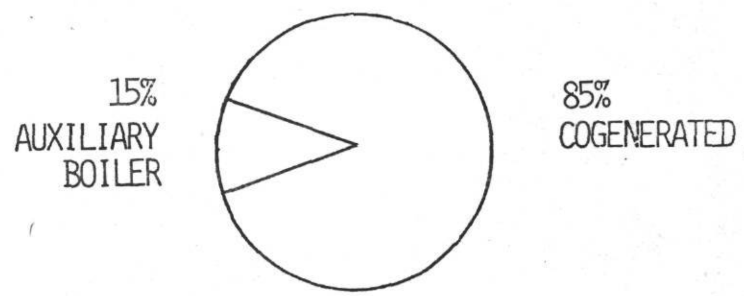
The price of electricity and natural gas purchased by the University used in the analysis averaged 4.87¢/KWH and $4.95 /MCF. The University is currently negotiating for the purchase of natural gas at $4.00/MCF which would further enhance the benefits of cogeneration.

Assumptions

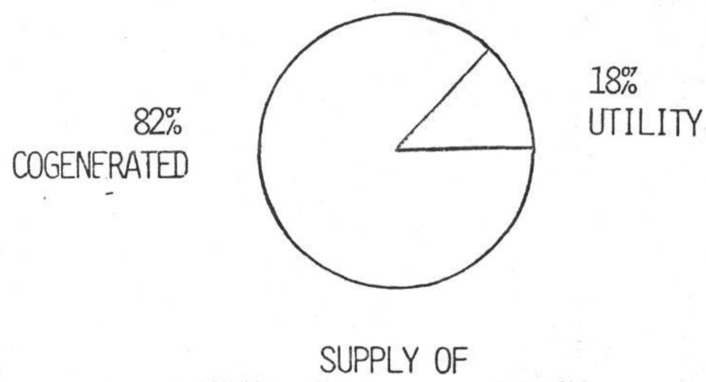
It was assumed that no electricity would be sold by SFA. It was also assumed that a standby power charge of $4.05/KW of peak demand would be levied each month by the utility company. Standby power is the electrical capacity that the utility must have in the event the cogeneration facility has an unscheduled outage. The campus would purchase excess electrical power when needed and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

A 2.5 MW diesel engine cogeneration system was found to be the most suitable for the University. The relatively inexpensive electrical rates had a somewhat adverse impact on the size of the system, which is not in proportion to the electrical demand. The initial cost of the system would be approximately $2.0 million. The system would save about $90,000 per year and have a simple payback of 22 years. However, if the standby power charge was removed, the cogeneration system would save $210,000 per year and have a simple payback of 9.5 years. The system would provide 85% of the annual thermal energy requirements and 18% of the annual electrical energy requirements, as shown on the charts.

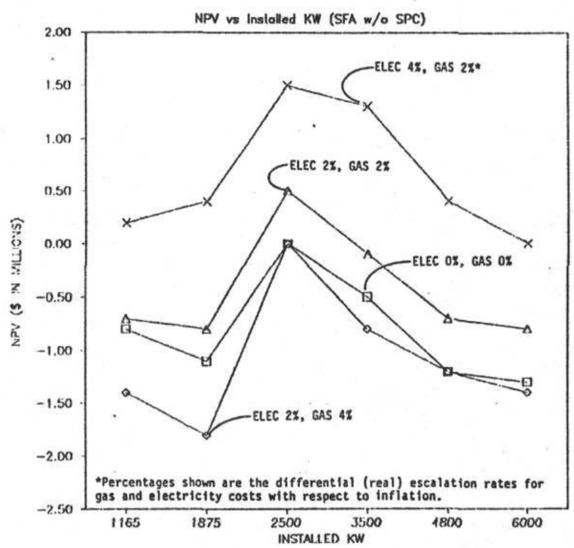


SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS



SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

The selection of the system was based on a net present value (NPV) analysis, which is a good indicator of the potential savings from the cogeneration system. For the case of maximum standby power charge, the NPV's for all systems analyzed were negative, therefore none of the systems were economically attractive. However, if the standby power charge was removed, the economics improve significantly. With no fuel or escalation cost above inflation, the NPV for the 2.5 MW system was $16,000. For the cases where the cost escalation rates for electricity and natural gas are 4% and 2%, respectively, the NPV is $1,500,000.



Stephen F. Austin University is negotiating for the purchase of natural gas at $4.00/MCF. If this were to come about, the 2.5 MW diesel engine system would save an additional $100,000 per year and have a payback of 6.5 years.

An absorption chiller could be used to increase SFA's thermal (hot water) demand and decrease its electrical demand. The analysis showed that an absorption chiller would save an additional $50,000/yr, but at a cost of $200,000.

A cogeneration system should not be installed at SFA at this time due to poor economics. However,

Recommendations

relaxation of the standby power charge, negotiation of $4.00/MCF for natural gas, and the addition of an absorption chiller would make cogeneration attractive.

COGENERATION SYSTEM ANALYSIS

for

SOUTHWEST TEXAS STATE UNIVERSITY

SAN MARCOS, TEXAS

for

PUBLIC UTILITY COMMISSION

ENERGY EFFICIENCY DIVISION

by

ENERGY MANAGEMENT GROUP
DEPARTMENT OF MECHANICAL ENGINEERING
TEXAS A&M UNIVERSITY

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August 31, 1985

SUMMARY REPORT

Cogeneration Analysis for Southwest Texas State University

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. Southwest Texas State University (SWTSU) was one of those sites, and it was selected for a detailed feasibility study. The campus has a high thermal energy to electrical power requirement, which makes cogeneration especially attractive. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared with that of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

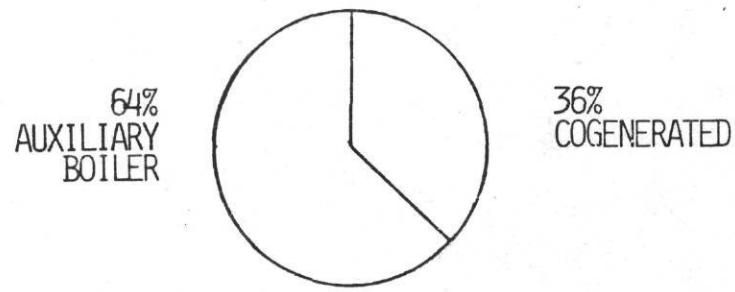
Most of the input information required for the analysis was obtained from the SWTSU Physical Plant personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. At the writing of this report, SWTSU was paying $4.25/MCF for natural gas and an average of 4.67 ¢/kwh for electricity.

Assumptions

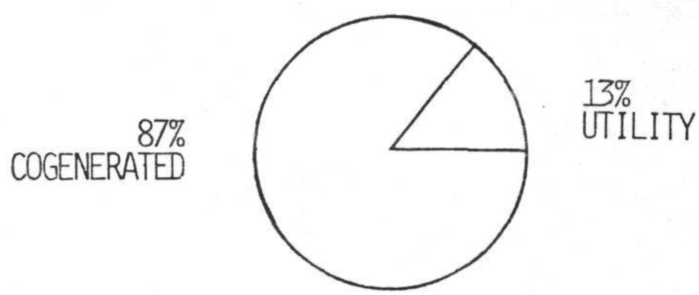
Due to state regulations, it was assumed that no electricity would be sold by SWTSU. The cogeneration system would therefore be a base load system. It was also assumed that no standby power charge would be levied by the utility company. The campus would purchase excess electrical power from the utility when needed. The life of the cogeneration system was asssumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum system for SWTSU was found to be a 4.5MW (megawatt) gas turbine with a heat recovery steam generator. The gas turbine system would be installed at one of the various sites on the complex. The installed cost would be approximately \$800/kW or about \$3,600,000. The electricity generated by the cogeneration system will cost about 5.0¢/kwh (including operating and maintenance cost) which is higher than purchased power. However, the steam produced by the cogeneration system would more than offset the higher cost of electricity. This gas turbine cogeneration system will save approximately \$800,000/yr and have a simple payback of 4.5 years. The system would provide 36% of the annual thermal energy requirements and 87% of the annual electrical energy requirements, as shown on the graphs below.

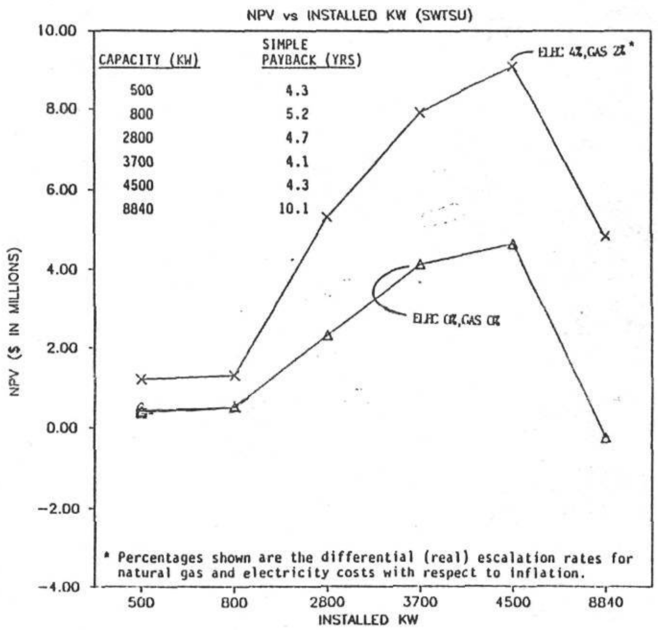


SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS



SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

A net present value (NPV) analysis is a good indicator of the potential savings from the cogeneration system. It projects the NPV of cogeneration system over the lifetime (20 years) and gives the NPV of the system in today's dollars. The graph below shows the NPV for six different gas turbines. With no fuel or electricity cost escalation above inflation, the 4.5 MW (4500 KW) system shows an NPV of 4.0 million dollars. The other curve shows the case when the escalation rates for electricity and natural gas are 4 percent and 2 percent, respectively. If this scenario were to become a reality, the 4.5 MW cogeneration system would have an NPV of 9 million dollars.



Recommendations

A 4.5 MW gas turbine cogeneration system should be installed at SWTSU. The system would save the State of Texas over $800,000/yr in reduced utility bills.

Cogeneration System Analysis

for

Texas Womans University
Denton, Texas

for

Public Utility Commission
Energy Efficiency Division

by

Energy Management Group
Department of Mechanical Engineering
Texas A&M University

Authors:

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August 31, 1985

SUMMARY REPORT

Cogeneration Analysis for Texas Woman's University

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. Texas Woman's University (TWU) was one of those sites, and it was selected for a detailed feasibility study. The campus has a high thermal energy to electrical power requirement, which makes cogeneration especially attractive. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared with that of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

Most of the input information required for the analysis was obtained from the TWU Physical Plant personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. TWU is currently paying $4.43/MCF for natural gas and electricity averages 6.20¢/KWH.

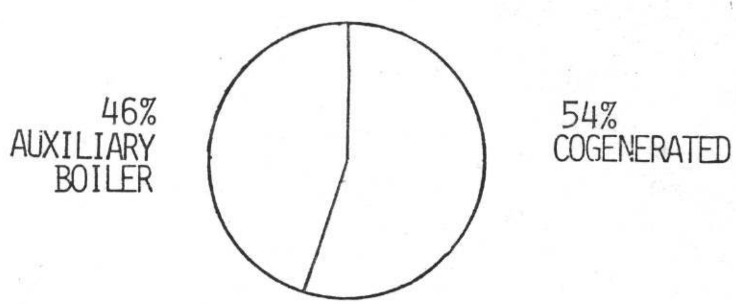
Assumptions

It was assumed that no electricity would be sold by TWU. The cogeneration system would therefore be a base load system. It was also assumed that a standby charge of $5.20 per KW of peak demand would be levied each month by the utility company. This assumption is based on the utility's current tariff concerning standby power. Standby power is the capacity that the utility must have in the event the cogeneration plant has an unscheduled down-time.

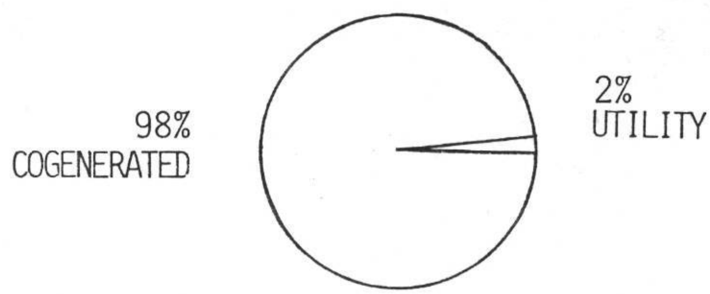
The campus would purhcase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum system for TWU was found to be a 3.7 MW (megawatt) gas turbine with a heat recovery steam generator. The gas turbine system could be installed at one of various sites on the campus. The installed cost would be approximately \$850/KW or about \$3,145,000. The electricity generated by the cogeneration system would cost about 6.14¢ /KWH (including operating and maintenance cost) which is slightly lower than the purchase price. Therefore, the steam produced by the cogeneration system is essentially "free." This gas turbine cogeneration system would save approximately \$800,000/yr and have a simple payback of 3.9 years. However, if the standby charge was relaxed, the cogeneration system would save about \$1,050,000/yr and have a simple payback of 3.0 years. The system would provide 54% of the annual thermal energy requirements and 98% of the annual electrical energy requirements, as shown on the charts.



SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS

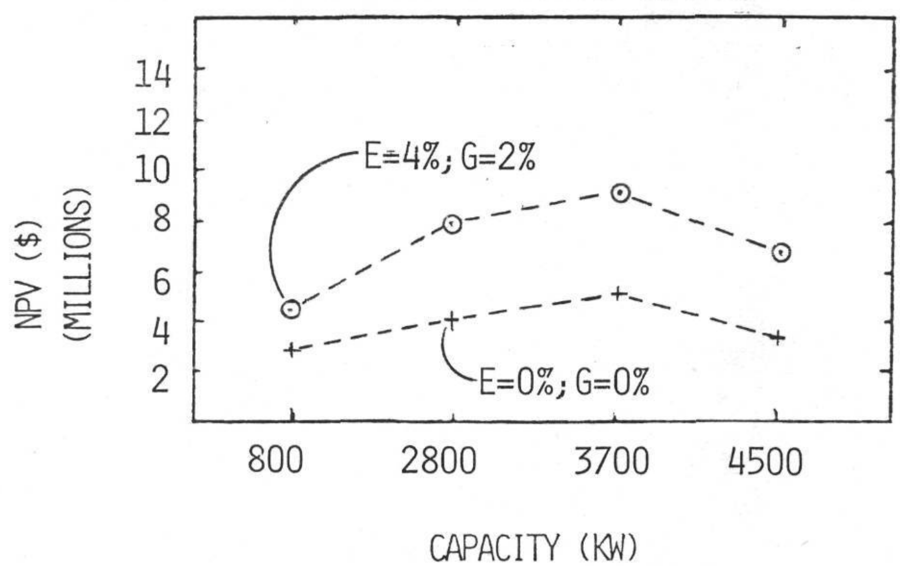


SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

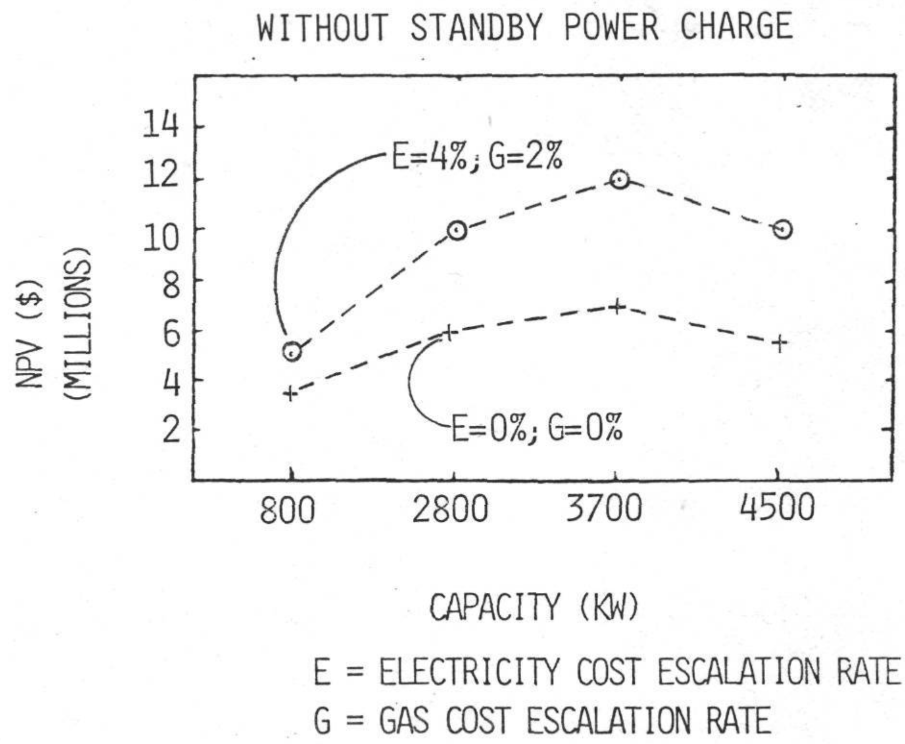
A net present value (NPV) analysis is perhaps the best indicator of the potential savings from the cogeneration system. It projects the present value (includes cost of cogeneration system) over the lifetime of the system (20 years) and gives the NPV in today's dollars. NPV analyses were performed for the case using the current standby power charge and for the case using no standby charge. The adjacent graphs show the NPV for four sizes of gas turbines.

With no fuel or electricity cost escalation above inflation, the 3.7 MW (3700KW) system shows an NPV from 4.8 million dollars to 7.2 million dollars depending on the standby charge. The other curve shown in each graph is for the case when the escalation rates for electricity and natural gas are 4 percent and 2 percent, respectively. If this scenario were to become a reality, the 3.7 MW cogeneration system would have an NPV from 9 million dollars to over 11 million dollars, again, depending on the standby charge.

WITH STANDBY POWER CHARGE



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE



Recommendations

A 3.7 MW gas turbine cogeneration system should be installed at TWU. The system would save the State of Texas from \$800,000/yr to over \$1,000,000/yr depending on the agreement arranged between the utility company and TWU concerning the standby power charges.

Cogeneration System Analysis

for

Texas Woman's University and North Texas State University
Denton, Texas

for

Public Utility Commission
Energy Efficiency Division

by

Energy Management Group
Department of Mechanical Engineering
Texas A&M University

Authors:

Dr. William E. Murphy, P.E.
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August 31, 1985

SUMMARY REPORT

Cogeneration Analysis for Texas Woman's University and North Texas State University

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. The combined electric utility needs of Texas Woman's University (TWU) and North Texas State University (NTSU) were considered as a possible candidate for cogeneration. This proposed combination is a result of studying each of the campuses separately. The analysis of TWU's cogeneration potential (see the report entitled "Cogeneration Analysis for Texas Woman's University") indicated that TWU's steam (thermal energy) demand could support a larger cogeneration system which would be more profitable provided the excess electricity generated by the plant could be economically used. The fact that NTSU lacks a centralized steam distribution system implies that it is not a good choice for cogeneration. However, NTSU's proximity to TWU and its electrical demand suggests that a larger cogeneration system be installed at TWU in order to generate electricity for both campuses. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared with that of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance of the boilers.

CELCAP was run without a cogeneration system to determine the base case costs. Various types and sizes of cogeneration systems were then run by CELCAP to determine the optimum system. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

Most of the input information required for the analysis was obtained from the TWU and NTSU Physical Plant personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month.

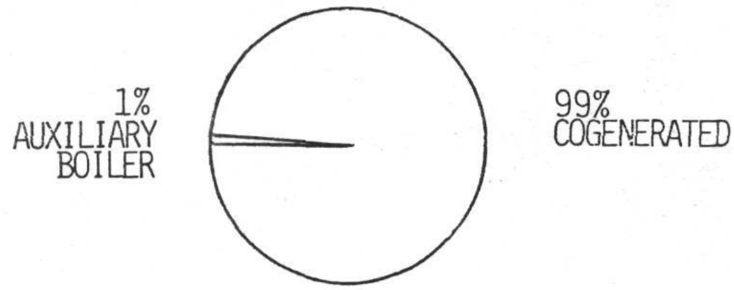
TWU is currently paying $4.43/MCF for natural gas. TWU and NTSU's combined electricity cost averages 6.08¢/KWH.

Assumptions

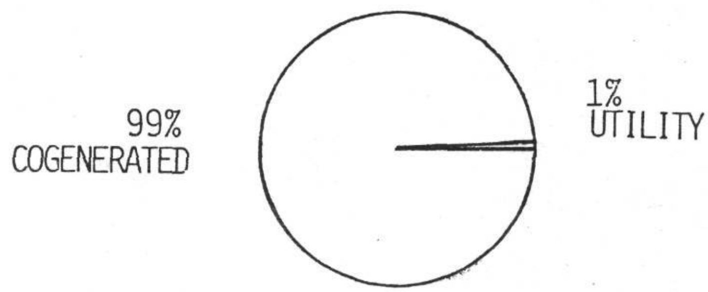
It was assumed that no electricity would be sold to the utility by TWU. Electricity would be transported, however, over utility owned transmission lines to NTSU. This process of transporting electricity, generated by someone other than the utility, to another user is called "wheeling." Wheeling power, however, is not currently allowed by Denton Utilities, and if current legislation requiring municipal utilities to cooperate with the Public Utility Commission (PUC) does not pass then this analysis would be void. It was also assumed that a standby power charge of $5.20 per kw of peak demand would be levied each month by the utility company. This assumption is based on the utility's current tariff concerning standby power. Standby power is the capacity that the utility must have in the event the cogeneration plant has an unscheduled down-time. The campus will purchase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The suggested system for TWU and NTSU was an 8.8 MW (megawatt) gas turbine with a heat recovery steam generator. The gas turbine system could be installed at one of various sites on the campus. The installed cost would be approximately $750/KW or about $6,600,000. The electricity generated by the cogeneration system would cost about 5.74¢ /KWH (including operating and maintenance cost) which is slightly lower than the purchase price. Therefore, the steam produced by the cogeneration system is essentially "free." This gas turbine cogeneration system will save approximately $1,300,000/yr and have a simple payback of 5.1 years. However, if the standby power charge was relaxed the cogeneration system would save about $1,740,000/yr and have a simple payback of 3.8 years. The system would provide 99% of the annual thermal energy requirements and 99% of the annual electrical energy requirements, as shown on the charts.



SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS



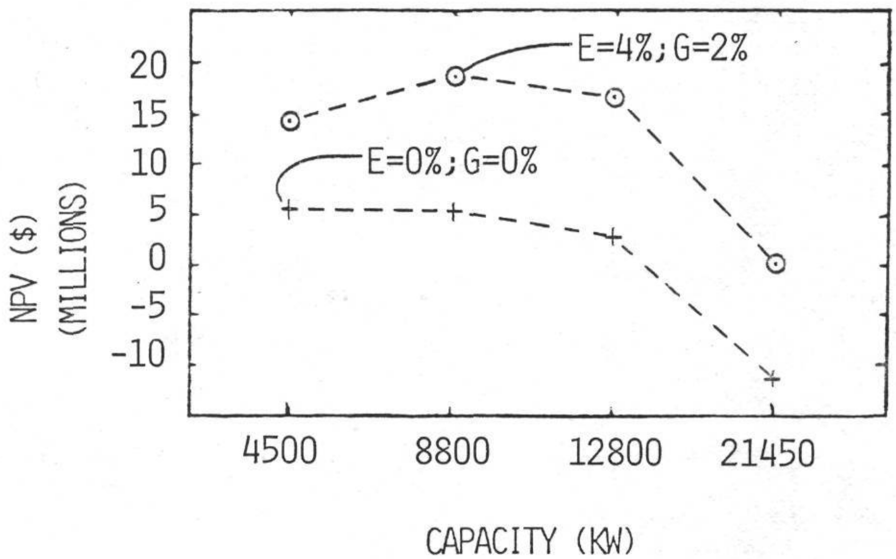
SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

A net present value (NPV) analysis is perhaps the best indicator of the potential savings from the cogeneration system. It projects the present value (includes cost of cogeneration system) over the lifetime (20 years) and gives the NPV of the system in today's dollars. NPV analyses were performed for the case using the maximum standby power charge and for the case using no standby charge. The adjacent graphs show the NPV for four sizes of gas turbines.

With no fuel or electricity cost escalation above inflation, the 8.8 MW (8800 kW) system shows an NPV from 4.0 million dollars to 10.4 million dollars depending on the standby charge. The other curve shown in each graph is for the case when the escalation rates for electricity and natural gas are 4 percent and 2 percent, respectively. If this scenario were to become a reality, the 8.8 MW cogeneration system would have an NPV from 16.6 million dollars to 22.3 million dollars, again, depending on the standby charge.

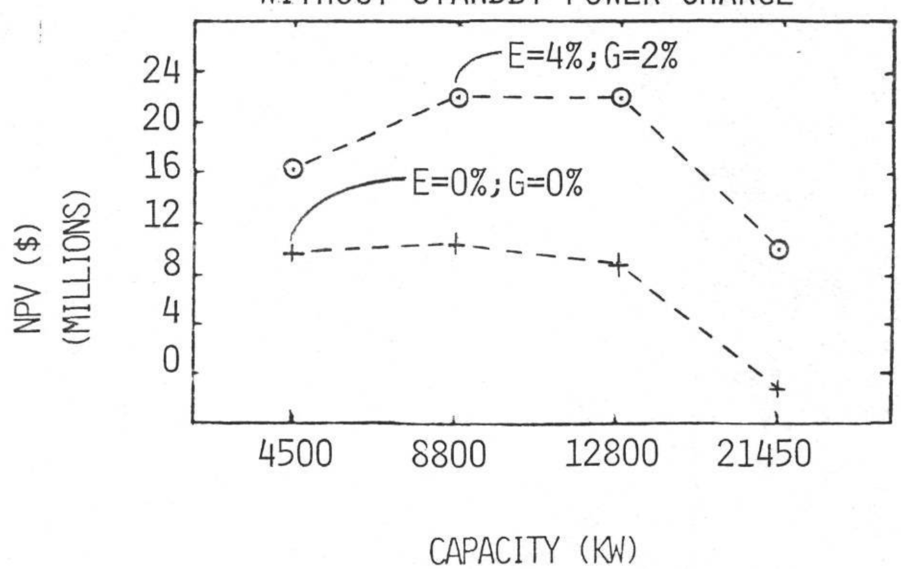
Even though the 8.8 MW system is suggested, other gas turbine systems near that size were also attractive. The 4.5 MW and 12.8 MW gas turbine systems have higher NPV's for some escalation rate cases. However, the 8.8 MW system is suggested because it appears to be the best overall choice.

WITH STANDBY POWER CHARGE



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE

WITHOUT STANDBY POWER CHARGE



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE

Recommendations

An 8.8 MW gas turbine system which would serve both TWU and NTSU could be installed at TWU at this time, providing that wheeling power is approved. The system could save the State of Texas from $1,300,000/yr to over $1,700,000/yr depending on the agreement arranged between the utility company and TWU concerning standby power charges. The above savings of $1,300,000/yr assumes a combined wheeling and standby charge of $5.20/KW, and the savings of $1,700,000/yr assumes no wheeling or standby charges.

COGENERATION SYSTEM ANALYSIS

for

UNIVERSITY OF HOUSTON-UNIVERSITY PARK

HOUSTON, TEXAS

for

PUBLIC UTILITY COMMISSION

ENERGY EFFICIENCY DIVISION

by

ENERGY MANAGEMENT GROUP
DEPARTMENT OF MECHANICAL ENGINEERING
TEXAS A&M UNIVERSITY

Authors:

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Dr. Warren M. Heffington, P.E.
S. T. Seshan
Jeffery N. Bolander
Alan Propp

August 31, 1985

Summary Report

Cogeneration Analysis for University of Houston-University Park Campus

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. The University of Houston-University Park (UH-UP) campus was one of those sites, and it was selected for a detailed feasibility study. The campus has high thermal to electrical power requirements, which makes cogeneration especially attractive. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the dollar savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall thermal efficiency of the cogeneration system ranges from 70 to 85 percent. This is compared to an efficiency of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Typical hourly loads were obtained from UH-UP Physical Plant personnel for one working day and one non-working day each month. CELCAP was run without a cogeneration system to determine the base case costs. Various sizes of cogeneration systems were then run by CELCAP to determine the optimum system size. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

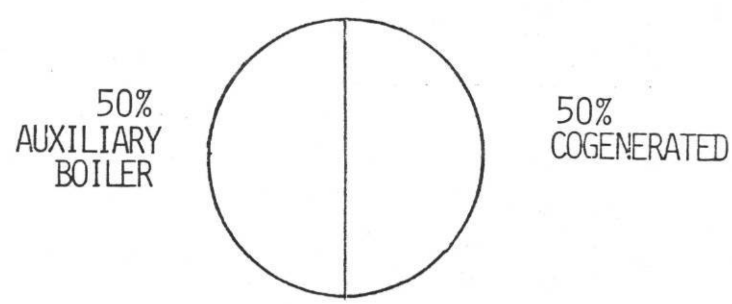
The prices of gas and electricity actually paid by UH-UP were used in the analysis. The displaced electricity price averages 4.76¢/KWH, and the current natural gas price was $4.00/MCF. Cogeneration systems are very sensitive to utility costs, and become more attractive when purchased electrical costs are high and purchased gas prices are low.

Assumptions

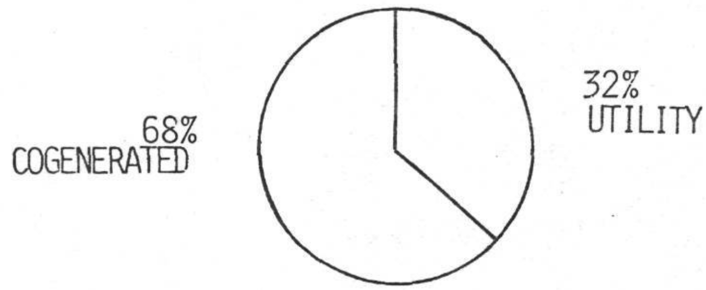
The installation cost of the cogeneration system was assumed to be $750/installed KW of capacity, based upon recent manufacturers' data. The assumption made for the operation and maintenance cost of the gas turbine system was $4.00/MWH. O&M costs of $1.10/KLB for steam generated in auxiliary boilers and $1.00/KLB for steam generated in waste heat recovery boilers were assumed. It was also assumed that no electricity would be sold by the UH-UP Campus. Furthermore, it was assumed that no standby power charge would be levied by the utility company. The cogeneration system is expected to have a life of 20 years. Long term bond interest was assumed to be 8% in the net present value (NPV) analysis.

Findings

The optimum system for the UH-UP campus was found to be an 8.8 Megawatt (MW) gas turbine. The gas turbine and waste heat boiler could be installed in the existing central steam plant. The installed cost of the system would be approximately $6,600,000. Using the current purchased utility prices, the cogeneration system would save approximately 1.8 million dollars a year, for a simple payback of 3.7 years. The optimum system will provide 50% of the annual thermal energy requirements and 68% of the annual electrical energy requirements, as shown on the graphs.

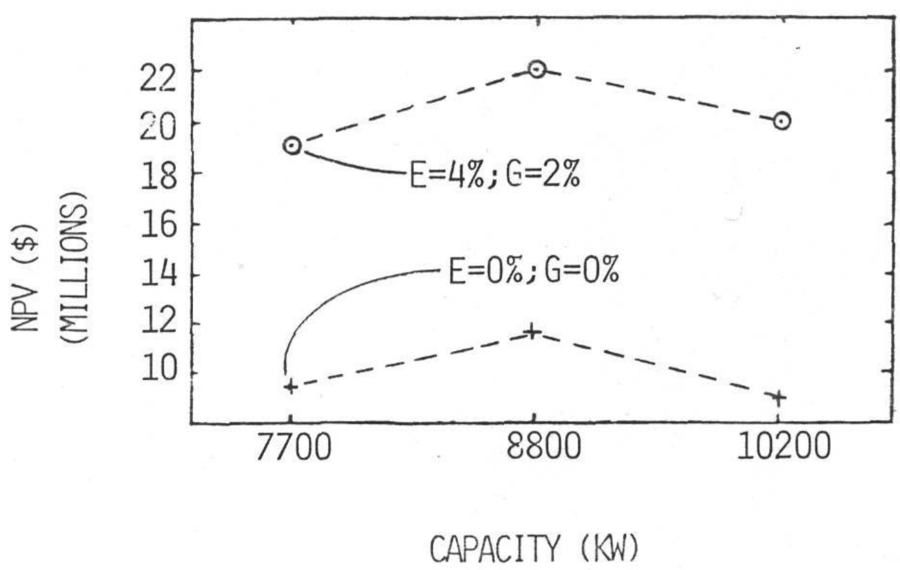


SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS



SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

A net present value (NPV) analysis is a good indicator of the potential savings from the cogeneration system. It projects the NPV over the system's lifetime (20 years) and gives the net value of the system in today's dollars. The adjacent figure shows the NPV for three different gas turbine sizes. With no fuel escalation above inflation, the 8.8MW system shows an NPV of over $11 million dollars. The other curve shown is for purchased electricity prices increasing faster than natural gas, i.e., electricity prices rising 4% above inflation and gas prices rising 2% above inflation over the 20 year lifetime. If that scenario were to become a reality, the 8.8MW cogeneration system would still be optimum, but would have an NPV of nearly $22 million dollars.



E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE

Recommendations	An 8.8MW cogeneration system should be installed at the University of Houston-University Park Campus. The system would save the State of Texas approximately 1.8 million dollars annually in reduced utility bills and pay for itself in approximately 3.7 years.

COGENERATION SYSTEM ANALYSIS

for

UNIVERSITY OF TEXAS AT DALLAS

DALLAS, TEXAS

for

PUBLIC UTILITY COMMISSION

ENERGY EFFICIENCY DIVISION

by

ENERGY MANAGEMENT GROUP
DEPARTMENT OF MECHANICAL ENGINEERING
TEXAS A&M UNIVERSITY

Authors:

Dr. W. E. Murphy, P.E.
Dr. W. D. Turner, P.E.
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Dr. Warren M. Heffington, P.E.
Jeffery N. Bolander
Alan Propp

August 31, 1985

Summary Report

Cogeneration Analysis for the University of Texas at Dallas

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies and later added two additional sites for consideration. The University of Texas at Dallas (UT-D) was one of those latter sites, and it was selected for a detailed feasibility study. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the dollar savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall thermal efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared to that of approximately 35 percent for a conventional power plant.

UT-D currently has a cogeneration system in operation. The system is a diesel engine (natural gas operated) with a heat recovery steam generator. The physical plant which houses the cogeneration system, boilers, and chillers is owned by UT-D, but it is operated by Thermonetics Inc.

The current use of the cogeneration system is to generate electricity to drive an electric chiller which operates periodically for 5 months of the year. The waste heat is recovered and piped to the UT-D campus. No electricity generated is utilized by the UT-D campus, other than that used for the chiller.

The cogeneration system is not economical during the time when it does not operate. Therefore, the authors investigated the feasibility of connecting the campus electrical distribution system to the cogeneration system. This connection would allow the diesel engine to operate throughout the year.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance (O&M) for the boilers.

CELCAP was run to simulate the existing mode of operation of the cogeneration system to determine the base case costs. Various operation modes were then run by CELCAP to determine the optimum mode of operation. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

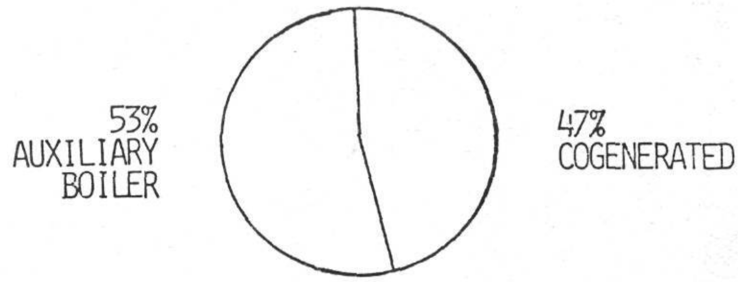
Most of the input information required for the analysis was obtained from Thermonetics and UT-D personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. UT-D is currently paying $4.14/MCF for natural gas used at the physical plant, and electricity averages 4.66¢/kwh. The electrical capacity of the cogeneration system is 3500 KW.

Assumptions

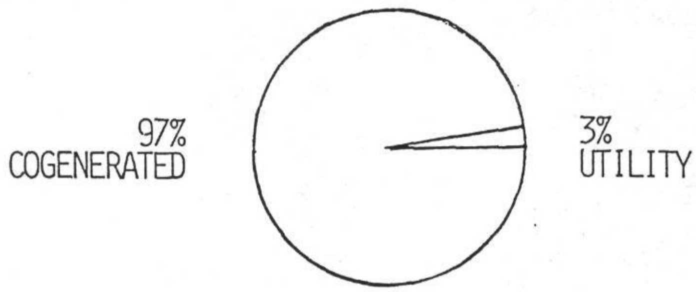
It was assumed that no electricity would be sold by UT-D to the utility grid. The cogeneration system would therefore be a base load system. It was also assumed that a standby power charge of $4.05/kw of peak demand would be levied each month by the utility company. This assumption is based on the utility's current tariff concerning standby power. Standby power is the capacity that the utility must have in the event the cogeneration plant has an unscheduled down-time. The campus would purchase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years; however, the system at UT-D is 5 years old. Therefore, the remaining life of 15 years was used in the analysis. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum operation mode for the cogeneration system at UT-D is where the engine follows the electrical load up to its capacity. The cost of interconnecting the campus electrical distribution system with the cogeneration system is about $225,000. The electricity produced by the cogeneration system will cost about 4.79¢/kwh (including O&M cost for the diesel engine) which is only slightly higher than the present purchase price for electricity. Therefore the steam produced by the system would be essentially "free." The system would provide 47% of the annual thermal energy requirements and 97% of the annual electrical energy requirements, as shown in the charts. The optimum mode of operation, however, would result in a net loss due to the standby power charge. Therefore, interconnection is not economically attractive at this time.



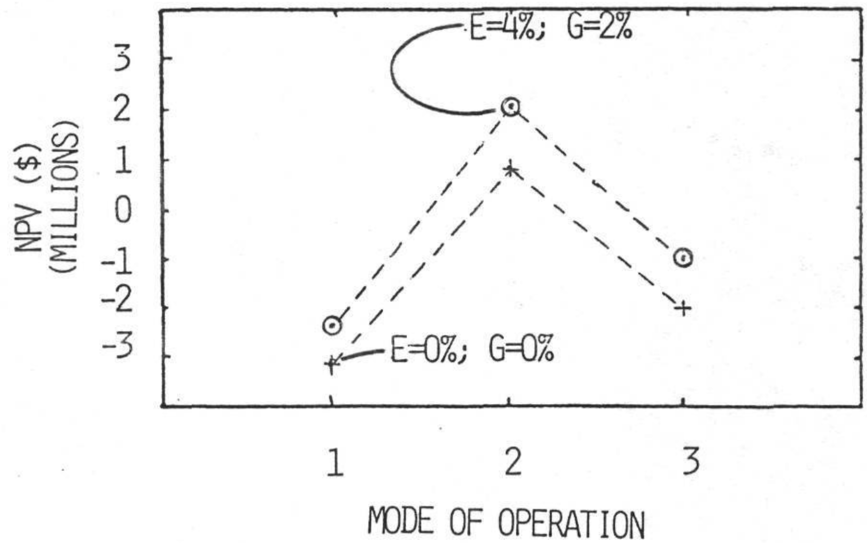
SUPPLY OF
ANNUAL THERMAL ENERGY
REQUIREMENTS



SUPPLY OF
ANNUAL ELECTRICAL ENERGY
REQUIREMENTS

On the other hand, if the standby power charge was repealed and the cogeneration plant could operate in parallel with the utility, the cogeneration system would be very profitable. The optimum mode of operation would save about $120,000/yr and have a simple payback of 1.9 years.

A net present value (NPV) analysis is perhaps the best indicator of the potential savings from the suggested operation mode. It projects the NPV (includes cost of making necessary alteration to the existing system) over the lifetime (15 years) and gives the NPV in today's dollars. The adjacent figure gives the NPV of the possible operation modes. With no fuel or electricity cost escalation above inflation, the NPV of the proposed operation mode is $750,000. For the case where the escalation rates for electricity and natural gas costs are 4 percent and 2 percent, respectively; the NPV is $1,900,000.



1 = RUN AT PEAK CAPACITY
2 = FOLLOW ELECTRIC LOAD
3 = FOLLOW STEAM LOAD

E = ELECTRICITY COST ESCALATION RATE
G = GAS COST ESCALATION RATE

Recommendations

The diesel engine cogeneration system at UT-D should not be connected to the campus electrical distribution system at this time. However, relaxation of the standby power charge would make interconnection feasible and would save the State of Texas about $120,000/yr in reduced utility bills.

Cogeneration System Analysis

for

University of Texas at El Paso
El Paso, Texas

for

Public Utility Commission
Energy Efficiency Division

by

Energy Management Group
Department of Mechanical Engineering
Texas A&M University

Authors:

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Jeffery N. Bolander

August 31, 1985

Summary Report

Cogeneration Analysis for University of Texas at El Paso

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies. The University of Texas at El Paso (UTEP) campus was one of those sites, and it was selected for a detailed feasibility study. The campus has high electrical power rates, which makes cogeneration especially attractive. At UTEP a cogeneration system will generate electricity cheaper than electricity purchased from a utility. In addition, dollar savings will come from the "free" thermal energy obtained from the waste heat of the diesel engine. The overall thermal efficiency of the cogeneration system ranges from 70 to 85 percent. This is compared to an efficiency of approximately 35 percent for a conventional power plant.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Typical hourly loads were obtained from UTEP Physical Plant personnel for one working day and one nonworking day each month. CELCAP was run without a cogeneration system to determine the base case costs. Various sizes of cogeneration systems were then run by CELCAP to determine the optimum system size. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

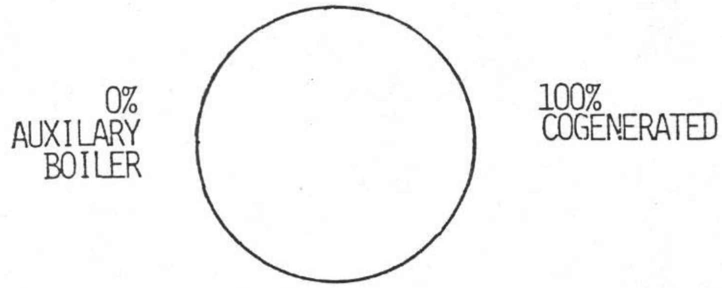
The prices of gas and electricity actually paid by UTEP were used in the analysis. The purchased electricity price averaged 7.56¢/KWH, and the current natural gas price of $4.50/MCF was used. Cogeneration systems are very sensitive to utility costs, and become more attractive when purchased electrical costs are high and purchased gas prices are low.

Assumptions

The thermal loads at UTEP are very low compared to the electrical power requirements, and electrical rates are high. Therefore, a natural gas fired, diesel-driven cogenerating system will be superior to a gas turbine system. A cost of $600/KW was assumed for the diesel system. This includes the construction costs for a small building immediately adjacent to the physical plant. The building will house the diesel generator, waste heat boiler, and electrical switchgear. Some construction costs will be incurred in tying into the existing campus hot water lines and into the campus power lines. These costs will be minimal however, since the cogeneration facility will be adjacent to both the thermal and electrical tie-ins. Operation and maintenance costs for the diesel cogenerator were assumed to be $6.00/MWH. The cost of operation and maintenance was assumed to be $1.10/Million Btu's for hot water generated in the auxiliary-fired boilers and $1.00/Million Btu's for hot water generated in the waste heat recovery boilers. It was also assumed that no electricity would be sold by UTEP and that a standby power charge of $16.50/KW of peak demand (ratchet demand) would be levied each month by the utility company. This assumption is based on the utility's current tariff concerning standby power. Standby power is the electrical capacity that the utility must have in the event that the cogeneration plant has an unscheduled downtime. The cogeneration system is expected to have a lifetime of 20 years. Long term bond interest was assumed to be 8% in the Net Present Value (NPV) analysis.

Findings

The optimum system for UTEP, based on the above assumptions, is a 7.0 MW diesel engine, the installed cost of which is $4.2 million. This engine would supply 95 percent of UTEP's electricity and all of its thermal energy requirements (see the following figure for graphical representation). With no standby power charge included, this system would save the state of Texas more that $800,000/yr in utility bills and have a simple payback of 5.1 years. However, inclusion of the $16.50/KW standby power charge causes the system to cost an additional $540,000/yr, yielding a large negative net present value.



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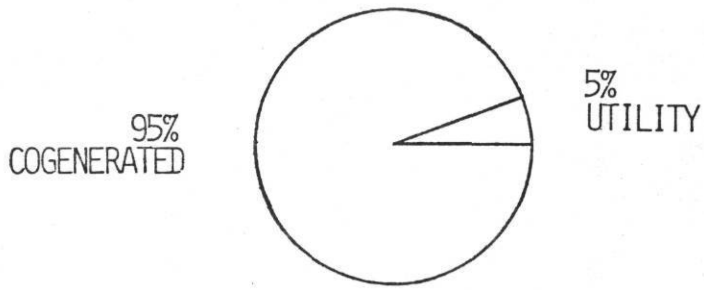

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For comparison's sake the standby power charge was relaxed to $5.20/KW, the next highest standby power charge encountered by the Energy Management group at Texas A&M University. Even with this reduced charge the NPV of the system was negative for two of the four gas and electricity escalation rate scenarios analyzed.

Recommendations

No cogeneration system should be installed at UTEP at this time. However, relaxation of the standby power charge to somewhat less than $5.20/KW might make the 7.0 MW system feasible.

Cogeneration System Analysis

for

University of Texas at San Antonio

San Antonio, Texas

for

Public Utility Commission

Energy Efficiency Division

by

Energy Management Group

Department of Mechanical Engineering

Texas A&M University

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Summary Report

Cogeneration Analysis for the University of Texas at San Antonio

Background

Cogeneration is defined as the generation of electrical power and the coincident recovery of useful thermal energy. A 1984 feasibility study conducted by the authors while under contract to the Energy Efficiency Division of the Public Utility Commission identified 20 potential cogeneration candidates among state agencies, and later added two additional sites. The University of Texas at San Antonio (UT-SA) was one of those latter sites, and it was selected for a detailed feasibility study. Since most cogeneration systems will generate electricity at approximately the same price as electricity purchased from a utility, the bulk of the dollar savings will come from the "free" thermal energy obtained from the waste heat of the prime mover (a gas turbine or a diesel engine). The overall thermal efficiency of the cogeneration system ranges from 70 to 85 percent. This efficiency is compared to that of approximately 35 percent for a conventional power plant.

UT-SA currently has a cogeneration system in operation. The system is a diesel engine (natural gas operated) with a heat recovery steam generator. The physical plant which houses the cogeneration system, boilers, and chillers is owned by UT-SA, but operated by Thermonetics, Inc.

The current use of the cogeneration system is to generate electricity to drive an electric chiller within the physical plant. The engine operates periodically for 8 months of the year. The waste heat is recovered and piped to the UT-SA campus. No electricity is currently being generated for the UT-SA Campus.

A cogeneration system can not save money unless it operates. Therefore, the authors investigated the feasibility of connecting the campus electrical distribution system to the cogeneration system. This connection would allow the diesel engine to operate throughout the year.

Method of Analysis

A cogeneration analysis computer program called CELCAP was obtained from the Navy's Civil Engineering Laboratory. Hourly steam loads as well as hourly electrical loads were required to optimize the cogeneration system. Other information required by CELCAP was the cost of natural gas, electricity, and operating and maintenance (O&M) for the boilers.

CELCAP was run to simulate the existing mode of operation of the cogeneration system to determine the base case costs. Various operation modes were then run by CELCAP to determine the optimum mode of operation. Both simple payback and net present value (NPV) economic analyses were made.

Input Information

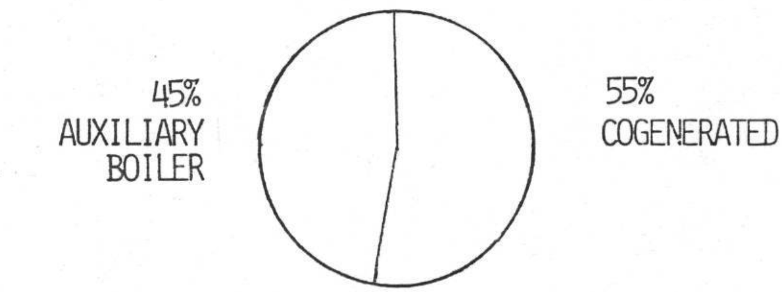
Most of the input information required for the analysis was obtained from Thermonetics and UT-SA personnel. Hourly steam and electricity loads (demands) were acquired for one working day and one nonworking day for each month. UT-SA is currently paying \$3.96/MCF for the gas used in the boilers and \$4.81/MCF for the gas used in the engine. Purchased electricity averages 4.19¢/KWH for the campus and physical plant. The electrical capacity of the cogeneration system is 3500 KW.

Assumptions

It was assumed that no electricity would be sold by UT-SA to the utility grid. The cogeneration system would therefore be a base load system. It also assumed that a standby power charge of \$4.50/KW of the peak demand would be levied by the utility company each month. This assumption is based on the utility's current tariff concerning standby power. Standby power is the electrical capacity that the utility must have in the event the cogeneration plant has an unscheduled down-time. The campus would purchase excess electrical power from the utility when needed, and produce steam in auxiliary boilers when needed. The life of the cogeneration system was assumed to be 20 years; however, the system at UT-SA is 5 years old. Therefore, the remaining life of 15 years was used in the analysis. Also, long-term bond interest was assumed to be 8 percent in the net present value (NPV) analysis.

Findings

The optimum operation mode for the cogeneration system at UT-SA is where the engine follows the electrical load up to its capacity. The cost of interconnecting the campus electrical distribution system with the cogeneration system is about \$250,000. The electricity produced by the cogeneration system will cost about 5.05¢/kwh (including O&M cost for the diesel engine). The system would provide 55% of the annual thermal energy requirements and 88% of the annual electrical energy requirements, as shown in the charts. The optimum mode of operation, however, would result in a net loss due to the standby power charge. Therefore, interconnection is not economically attractive at this time.



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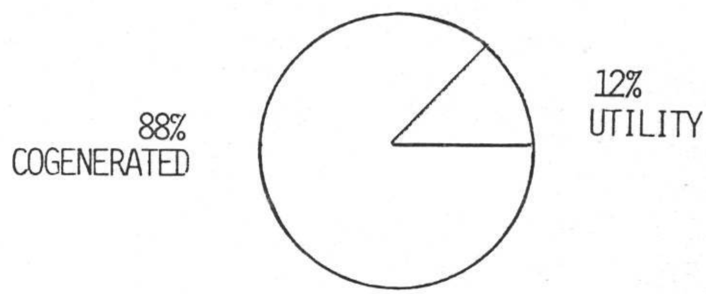

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On the other hand, if the standby power charge was repealed and the cogeneration plant could operate in parallel with the utility, the cogeneration system would be very profitable. The optimum mode of operation and interconnection of the two systems would save about $70,000/yr and have a simple payback of 3.6 years. Also, the NPV showed that with no fuel or electricity cost escalation above inflation, the NPV of the proposed operation mode is zero (no net profit over do nothing case.) For the case where the escalation rates for electricity and natural gas costs are 4 percent and 2 percent, respectively; the NPV is $1.5 million.

Recommendations

Two contractural problems exist which will preclude the implementation of this cogeneration system at UT-SA.

1. Rider E3 of the contract between UT-SA and City Public Service Board (CPSB) of San Antonio, effective November 29, 1984, states... "The wiring installation of the customer shall be made and maintained in a manner that will prevent operation of the power sources in parallel." During peak power demands at UT-SA, the existing cogeneration system could supply about 3.6 MW, but the CPSB would be supplying about 3.4 MW, i.e., the power would be paralleled. At this present time this is forbidden by contract.

2. In the event that UT-SA generates all of their own electrical power, rider E3 of the contract states that a standby service..."monthly charge of $4.50 per KW; which could conceivably result in an $80,000 to $90,000 monthly service charge, even if no electricity were purchased by UT-SA. Since this monthly service charge is greater than the savings from cogeneration, the recommendations herein could not be implemented.

A third problem also exists with cogeneration at UT-SA. This problem, however, will not preclude cogeneration, but merely discourages it. The CPBS also controls natural gass prices and levies a penalty on the gas burned in the diesel engine to produce electricity. They charge $3.96/MCF for boiler gas and $4.81/MCF for engine gas. This bias against cogeneration dramatically affects the economics of cogeneration. A reduction in engine gas price from $4.81 to $3.96/MCF would save thousands of additional dollars for the cogeneration system. The City of San Antonio buys state-owned gas to burn in their power-generating plant at a price considerably below the $4.81/MCF fee charged for natural gas. This practice could be viewed as the CPBS making money off the state gas when selling it to another state agency and should not be allowed.

The cogeneration system at UT-SA should not be connected to the campus electrical distribution system at this time. However, relaxation of the standby charge would make interconnection feasible which would save the State of Texas about $70,000/yr in reduced utility bills. Therefore, the State of Texas has to find a solution to the current contracts with the City Public Service Board of San Antonio before this recommendation can be implented.