THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
345 E. 47 St., New York, N.Y. 10017

82-GT-298

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Operating Flexibility and Economic Benefits of a Dual-Fluid Cycle 501-KB Gas Turbine Engine in Cogeneration Applications

The flexibility of the Dual-Fluid Cycle 501-KB engine in accommodating to time varying process steam demand and peaking power requirements is described. Economic aspects of this engine in cogeneration applications are discussed relative to ownership by a utility, a process steam user or a third party. A specific installation is described for a Dual-Fluid Cycle unit operating in combination with two basic 501-KB cogeneration units. The resultant cost of electrical power for this installation is compared to local commerical rates.

INTRODUCTION

It has been recognized for many years that industrial process steam and electrical power can be generated in a combined plant at lower cost than would be incurred in separate plants. Serious interest in cogeneration installations has both broadened and intensified in the United States during the past two to three years. This situation has been brought about by the combination of several factors. These are:

- Delays in bringing new nuclear plants on line, resulting in a lower than planned rate of increase in generating capacity.
- Growth in adult population (family units) and in industrial activity resulting in increased electrical power demands despite the ameliorating effects of conservation efforts.
- Continuous abrupt increases in fuel and electrical energy costs.
- Recognition that more efficient use of nonrenewable energy sources is critical to bridge the necessary time gap required to bring new energy into widespread service.
- Recognition of the cost benefits and profit potential created by cogeneration installations.

The gas turbine engine role in cogeneration is well recognized. Operation on natural gas fuel is a practical first step for small to moderate size plants (1 to 30 MW). These units can be readily converted to the use of medium to high Btu coal, lignite, coke or biomass gas when it becomes commercially available. The gas turbine of course also has a role with fluidized beds of gasifiers in self-contained installations using alternative fuels. These applications however are considered to be beyond the scope of this paper.

Identification and classification of steam users in the United States appropriate for cogeneration applications has been addressed in a number of recent studies, Ref. 1. Generally, those identified have been limited to base load (~90% time available) operations. Seasonal or time varying process steam users also present opportunities for cogeneration installations if the proper equipment were available. The Dual-Fluid Cycle gas turbine engine, patented by Dr. Dah Yu Cheng, and developed by International Power Technology, Inc., represents a significant advancement in gas turbine engine technology. Because of its cycle concept and basic design features, it is particularly well suited to cogeneration installations and has unusual flexibility in utilizing engine exhaust heat energy to produce process steam and/or to increase the power output and system efficiency of the electrical generating plant.

THE CHENG DUAL-FLUID CYCLE TURBINE ENGINE

Basic Concept

The Cheng Dual-Fluid Cycle (DFC^{TM}) combines Brayton and Rankine cycles simultaneously in one machine so that the principal operational limitations of both cycles are relieved. This is accomplished by using exhaust heat energy of the turbine to produce and superheat steam, which is then injected into the combustion section of the engine as illustrated in Fig. 1.

Contributed by the Gas Turbine Division of the ASME.

the DFC mode with resultant increases in thermal efficiency and power output. The gains in power output and thermal efficiency calculated for a number of different engines are shown in Fig. 2.

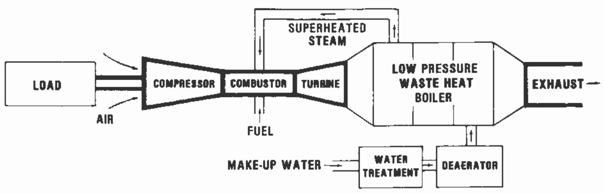
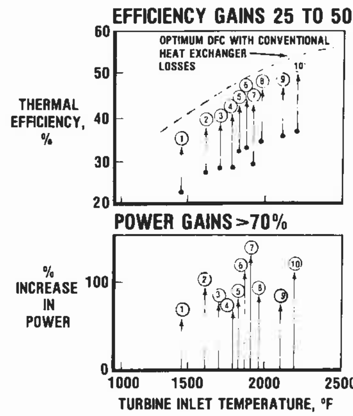


Fig. 1 The Cheng Dual-Fluid Cycle Turbine Engine.



SYMBOL	ENGINE
1	SOLAR SATURN
2	SOLAR CENTAUR
3	GE M7652
4	ALLISON 501-K
5	BBC TYPE 11
6	TPM FT4C-3F
7	GARRETT IE990
8	COOPER RT-264 (RB211-22B MOD)
9	COOPER RT-261 (LM 2500 MOD)
10	CW MOD-POD 35A (LM 5000 MOD)

Fig. 2 Cycle performance improvements with Dual-Fluid Cycle operation.

Additional fuel must be burned to raise the injected steam to the rated turbine inlet temperature. The added mass flow of the steam produces an increase in work output from the turbine. A large power increase results from a modest increase in fuel consumption, resulting in a large increase in engine thermal efficiency. For the Allison 501-KB, 19% additional fuel yields an increase of 75% in power output and 40% in thermal efficiency. Alternatively, by reducing the throttle setting and the steam flow rate, the same power output of the basic engine can be maintained at a lower turbine inlet temperature, resulting in a smaller increase in engine thermal efficiency but a large increase in engine life.

The presence of superheated steam in the turbine exhaust has two beneficial effects on the boiler performance. The attendant higher heat transfer coefficient results in improved efficiency as does the fact that more heat can be extracted from the gas side with the same drop in gas side temperature than for a mixture of air and combustion gases alone.

It has been patented (Patent No. 4,128,994) that the ratio of Brayton cycle to Rankine cycle fluids is critically linked to the engine cycle parameters for achieving peak thermal efficiencies of a given engine. Thus, within the operational range of this ratio, as limited by boiler surface area or gas turbine exit temperature, the Dual-Fluid Cycle engine can be operated away from its peak load condition to accommodate various circumstances (high ambient temperature or low ambient pressure) but will maintain high overall efficiency.

The availability of steam for injection into the combustion region provides two additional advantages. A small amount of the steam injected upstream of the combustion region can serve the additional function of suppression of NO_x production. Furthermore, steam, with its attendant higher heat transfer coefficient, can be used for blade or vane cooling in the turbine, rather than air extracted from the compressor.

There are no previous publications describing the Dual-Fluid Cycle engine, however it is described in detail in several patents , Ref. 2.
Most gas turbines can be modified for operation in the DFC mode.

Full realization of these gains depends upon the particular engine design, as do the engine modifications required to operate in the DFC mode. The IPT patents are method patents and cover the operation of any make of gas turbine in the DFC mode.

The DFC engine can be utilized for electrical power generation, or mechanical power applications such as fluid pumping, gas compression or marine propulsion. The application being addressed in this paper is cogeneration. Control concepts for DFC cogeneration applications are described in other patents , Ref. 2 and 3.

Application to the DDA 501-KB Engine

Application of DFC to the Detroit Diesel Allison 501-KB engine currently is being undertaken. A cutaway view of the engine is shown in Fig. 3.

The energy balance for DFC operation is given in Table I and the corresponding cycle operating parameters at rated power are given in Fig. 4, as obtained from an IPT analysis. Engine performance at essentially the same operating conditions as determined by DDA confirms these results and is presented in Fig. 5.

The increase in engine thermal efficiency at full DFC operation with increased power is about 40%. The DFC operation at no increase in power output compared to the basic engine results in a 20% increase in engine thermal efficiency. This latter efficiency gain is achieved with a reduction of turbine inlet temperature from 1800°F (1255°K) to 1500°F (1089°K). It has been estimated that engine life is doubled for every 50°F (27.8°K) reduction in turbine inlet temperature.

Modifications to the engine to accommodate the increased mass flow through the turbine and the increased power output are anticipated to be modest and are currently being defined. The inherently broad operating margins of this aircraft derivative engine provide for retention of good operating margins with the added mass flow of the steam.

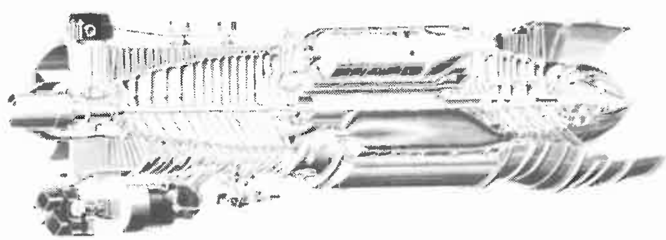


Fig. 3 Allison model 501-K series industrial gas turbine engine.

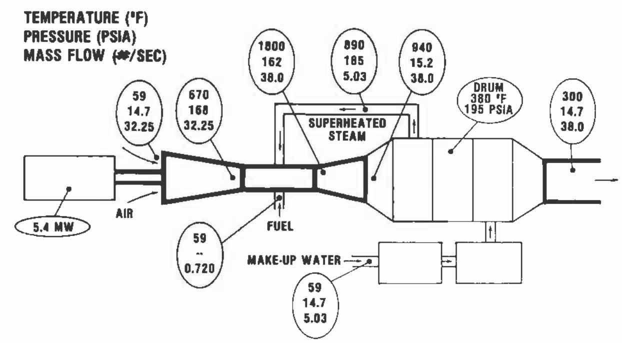


Fig. 4 DFC 501-KB turbine engine cycle operating parameters.

TABLE I
ENERGY BALANCE FOR DFC 501-KB

COMPRESSOR:	Inlet - Pressure, psia	=	14.7	101.4×10^3 newtons/m^2
	- Temperature, Deg F	=	59.0	288°K
	Discharge - Pressure, psia	=	167.58	1156×10^3 newtons/m^2
	- Temperature, Deg F	=	670.5	627.7°K
	Pressure Ratio (CPR)	=	11.4	
	Efficiency (%)	=	83.3	
	Compressor Work (BTU/Lb Air)	=	151.05	351.36×10^{-6} kJ/kg
COMBUSTOR:	Efficiency (%)	=	99.5	
	Pressure Drop (%)	=	3.5	
	Low Heat Value (BTU/Lb Fuel)	=	18400	$42{,}800 \times 10^{-6}$ kJ/kg
	Air-Fuel Ratio	=	44.66	
	Heat Input (BTU/Lb Air)	=	409.94	953.56×10^{-6} kJ/kg
TURBINE:	Inlet - Pressure, psia	=	161.71	1116×10^3 newtons/m^2
	- Temperature, Deg F	=	1800	1255°K
	Discharge - Pressure, psia	=	15.20	104.9×10^3 newtons/m^2
	- Temperature, Deg F	=	941.2	778°K
	Pressure Ratio	=	10.64	
	Efficiency (%)	=	89.7	
	Turbine Work (BTU/Lb Air)	=	318.03	737.77×10^{-6}
WORK TO RAISE WATER PRESSURE:	Inlet - Pressure, psia	=	14.7	101.4×10^3 newtons/m^2
	- Specific Volume (CuFt/Lb)	=	0.0163	.001018 m^3/kg
	Exit - Pressure, psia	=	175.959	1214×10^3 newtons/m^2
	- Specific Volume (CuFt/Lb)	=	0.0162	.001011 m^3/kg
	Work Required (BTU/Lb)	=	0.076	0.177×10^{6} kJ/kg
OVERALL PERFORMANCE:	Thermal Efficiency (%)	=	40.71	
	Mixture Ratio (Lb Water/Lb Air)	=	0.1559	
	Useful Work (HP/Lb Air)	=	236.09	520.48 HP/kg

COGENERATION APPLICATIONS

Operational Characteristics

The presence of a waste heat boiler as an essential element of the Dual-Fluid Cycle engine provides for direct application to cogeneration with modest added cost. A schematic of a cogeneration application is shown in Fig. 6. Obviously essential components not necessary for the understanding of the unique aspects of the system, such as water pumps, steam separators, water preheat and deaerator steam sources, etc., are not shown.

The unique operational flexibility of the DFC cogeneration system is illustrated in Fig. 7, for a DDA 501-KB unit. The heavy line represents the operating characteristics of the basic 501-KB engine as it is throttled back to meet reductions in process steam demand. It is clear that the power output is reduced accordingly. For DFC operation, as the process steam demand is reduced, that portion of the steam may be deverted through the superheater to the engine to increase the generated electrical power. Accompanying the increase in power output is an increase in the efficiency of electrical power generation. This operational flexibility opens up a broader cogeneration market to include noncontinuous steam users.

Supplemental firing in the exhaust gas flow upstream of the boiler is used in some basic gas turbine cogeneration applications to increase the rate of process steam production. This is illustrated in Fig. 8, for a basic DDA 501-KB cogeneration unit by the horizontal dotted line so identified. The supplemental firing combustion air is preheated in the gas turbine engine to about 940°F (778°K). In addition, the stack heat enthalpy, with special design of the boiler, economizer and feedwater heater for supplemental firing is little more than for the no supplemental firing operation. Because of these two factors, the additional process steam resulting from the supplemental firing operation is generated at higher efficiency than an equal amount of steam in a fired boiler.

Similarly, with special design of the boiler and heat exchangers, dual-engine firing can be employed to produce additional process steam at any DFC engine power output from the basic engine value to full DFC operation. This provides a broad operating regime for the DFC cogeneration unit, as indicated in Fig. 8. The dual-engine firing process for the DFC unit enjoys the same high efficiency for the same reasons as for the basic engine cogeneration unit. In addition, for the DFC unit, the boiler and heat exchanger efficiencies are increased further because of the presence of superheated steam in the engine exhaust gas flow, because more heat energy can be extracted for a given gas side temperature drop.

In regard to satisfying the fuel dual-purpose requirement to qualify for cogeneraion under PURPA in the United States, this latter effect is very important. The usable exhaust gas heat energy for a basic 501-KB engine will produce approximately 20,000 lb/hr (9072 kg/hr) of saturated process steam at 165 psia (1138 x 10^3 newtons/m^2). For DFC operation at full power an additional 18,000 lb/hr (8165 kg/hr) of superheated steam is required, and is provided using dual-engine firing. The primary use of this additional steam is to increase the magnitude and efficiency of electrical power generation. The secondary use of the additional steam is to give up heat energy in the boiler and to increase the efficiency of generating both the process steam and the DFC steam.

Economic Benefits

The economic benefits of the DFC cogeneration unit are illustrated herein by comparison with a basic engine cogeneration unit. The engine used in this comparison is the DDA 501-KB. The comparison is made for three cases of different ownership of the cogeneration equipment:

Case A - Ownership by the process steam user, with electrical energy being sold to a utility to reduce the cost of process steam.

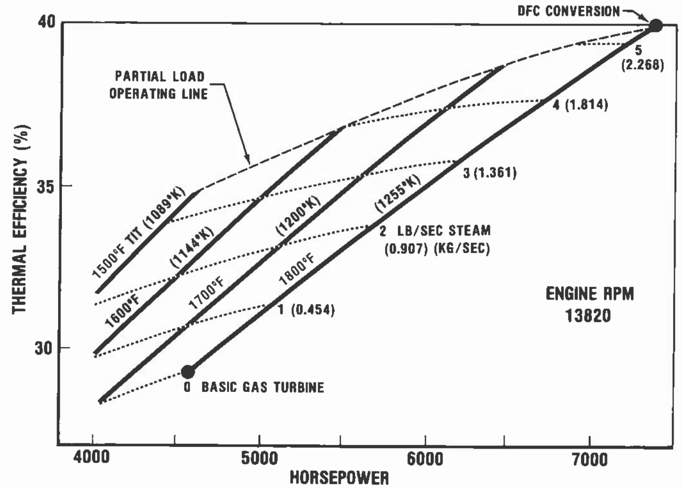


Fig. 5 DFC 501-KB engine performance.

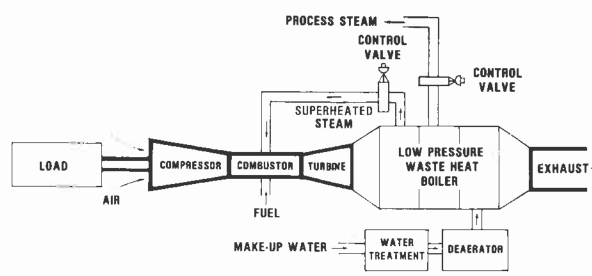


Fig. 6 DFC Cogeneration application.

Case B - Ownership by a utility, with process steam being sold to an industraial process plant to reduce the cost of electrical energy production.

Case C - Ownership by a third party business venture, with both steam and electrical energy being sold to produce a profit for the venture.

The following assumptions have been made in the analysis:

Capital Costs

Basic 501-KB Unit	
Hardware installed	$ 1,800,000
A&E site work	450,000
	$ 2,250,000
DFC 501-KB Unit	
Hardware installed	$ 2,650,000
A&E site work	450,000
	$ 3,100,000

These costs are in 1981 dollars and represent a specific installation where certain system elements exist, i.e. steam distribution system, compressor for the natural gas fuel, oil day tanks, air compressor and certain site improvements. For a completely new installation, an additional cost would have to be added equally to both systems to provide for these missing elements.

Price for Electricity

Electrical energy is credited at an avoided cost utility purchase price of $0.071/kWhr average annual rate. No capacity or performance incentive payments have been included.

Price for Steam

Steam is priced at fired boiler (80% efficiency) fuel costs. At this price, the process steam user buying the steam from the cogeneration plant owner avoids capital costs, interim replacement, G & A and operation and maintenance costs compared to operating his own steam plant. In addition to these savings, as more third party owners or possibly utility owners compete to provide industrial process steam, the market price may be further reduced by the forces of supply and demand. This fact must be recognized in evaluating cogeneration system economies.

Natural Gas Fuel Costs

An industrial-user natural gas price of $0.4608 per therm has been used in this analysis. No reduction in fuel price has been assumed for cogeneration operation. In some installations reduced fuel rates may be or may become available. Gaseous fuels from coal, lignite, coke or biomass gasification would be usable as alternative fuels when such fuels become generally available. Added costs may be incurred in converting to alternative gaseous fuels, the amount depending upon the Btu content.

Process Steam

Saturated steam at 165 psig (1138×10^3 newtons/m^2) from the boiler has been assumed with 99% quality. Sixty percent condensate return at 200^{o}F (366^{o}K) has been used in this analysis with make-up water at 70^{o}F (294^{o}K). In most installations, recovery of heat energy and clean water from the available process steam return condensate would be a prudent design feature.

Financing

For Cases A (industrial owner) and C (private venture owner), financing on the basis of 10 years at 20% interest has been assumed. For Case B (utility owner), financing on the basis of 20 years at 20% interest has been assumed.

Other Costs

The following system costs have been used in the analysis:

- o Interim replacement,
  1.8% of capital cost per year.
- o Insurance,
  1.3% of capital cost per year.
- o General and Administrative,
  2.0% of capital cost per year.
- o Operations and Maintenance,
  2.1% of capital cost per year.

Fuel Costs

Fuel costs for engine operation for the basic units include the fuel energy for heating water for NO_x control to the 1800^{o}F (1255^{o}K) turbine inlet temperature. Injection of part of the DFC steam upstream of the combustion region provides for NO_x control for that system.

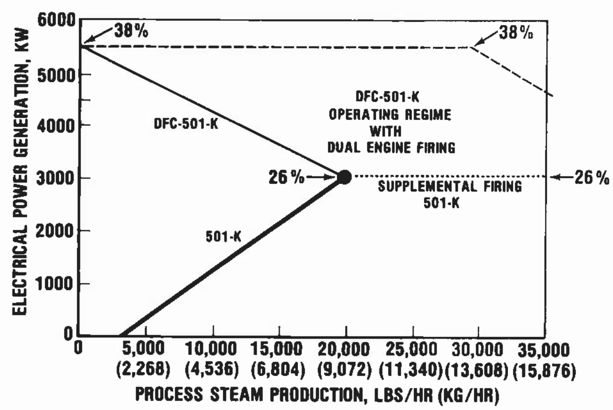


Fig. 7 Cogeneration system performance.

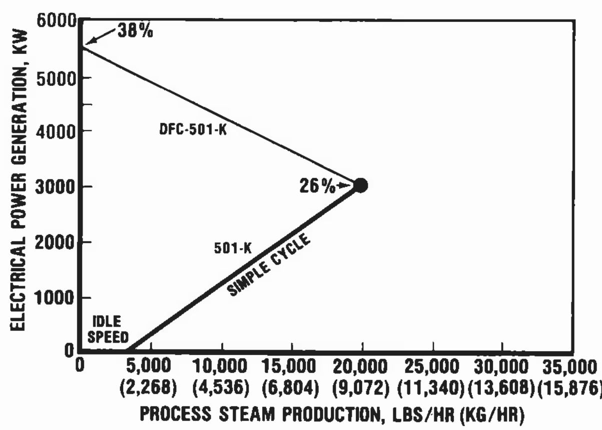


Fig. 8 Cogeneration system performance with dual firing.

The overall system non-fuel costs for Cases A and C are presented in Table II.

TABLE II
FIXED AND OPERATION AND MAINTENANCE COSTS
Cases A and C

SYSTEM		1 Basic 501-KB Unit	1 DFC 501-KB Unit
Power Output		2900kW	5400kW
Capital Cost		$ 2,250,000	$ 3,100,000
ANNUAL COSTS			
Debt (10 yr-20%)		$ 536,676	$ 739,421
Interim Repl.	1.8% c.c.	40,500	55,800
Insurance	1.3% c.c.	29,250	40,300
G & A	2.0% c.c.	45,000	62,000
O & M	2.1% c.c.	47,250	65,100
TOTAL $/yr		$ 698,676	$ 962,621
at 8400 hr, $/hr		83	115

This comparison is based on a single unit producing 25,000 lb/hr (11,340 kg/hr) of process steam. Similar costs for Case B are presented in Table III.

TABLE III
FIXED AND OPERATION AND MAINTENANCE COSTS
Case B

SYSTEM		2-Basic 501-KB Units	1-DFC 501-KB Unit
Power Output		5800kW	5400kW
Capital Cost		$ 4,500,000	$ 3,250,000
ANNUAL COSTS			
Debt (20 yr-20%)		$ 924,104	$ 667,409
Interim Repl.	1.8% c.c.	81,000	58,500
Insurance	1.3% c.c.	58,500	42,250
G & A	2.0% c.c.	90,000	65,000
O & M	2.1% c.c.	94,500	68,250
TOTAL $/yr		$ 1,248,104	$ 901,409
at 8400 hr, $/hr		149	107

Here the plants are compared on an equivalent power basis and for a process steam demand of 50,000 lb/hr (22,680 kg/hr) to assure the full cogeneration benefits of the basic units. Supplemental or dual-engine firing is employed in each system. An increase in capital cost is imposed for the DFC unit to provide for the larger boiler and water treatment system required.

Economic comparisons for Case A are given in Table IV, for a process steam demand of 25,000 lb/hr (11,340 kg/hr). The basic 501-KB unit develops 2900 kW, produces 19,500 lb/hr (8845 kg/hr) of process steam and requires supplemental firing for the remaining 5500 lb/hr (2495 kg/hr). The DFC unit develops 5400 kW and requires dual engine firing for the DFC steam and 5000 lb/hr (2495 kg/hr) of process steam. The resultant cost of steam to the process owner is 23% higher for the basic 501-KB unit.

Comparison for Case B is made on the basis of essentially the same electrical power plant size to provide a true, meaningful assessment for the utility owner. A 50,000 lb/hr (22,680 kg/hr) process steam demand is chosen, so that two basic units are required having a combined power output approximately equal to the single DFC unit. Increased firing is required for the single DFC unit, requiring a larger boiler and water treatment plant. This is reflected in the increased capital cost shown in Table III compared to Table II. The resulting economic comparison is given in Table V.

It may be seen that the resultant cost per kilowatt of electrical energy is essentially the same for both systems. The characteristics of the DFC unit that provide operational flexibility are very important, however, as is illustrated by comparing the electrical energy costs for the two systems when the process steam demand is eliminated. The DFC system produces electrical energy at below avoided cost rate, while the basic unit system is above the avoided cost rate.

Third party ownership, Case C, considers a single unit comparison, as in Case A. The significantly greater net income before taxes for the DFC system is clearly shown in Table VI. Under the prevailing tax law in the U.S., with its more generous investment tax credit allowances than in recent years, third party cogeneration system ownership becomes a very attractive

TABLE IV
PERFORMANCE AND ECONOMIC COMPARISON

CASE A PROCESS OWNER SELLS ELECTRICAL ENERGY

	1 Basic 501-KB Unit	1 DFC 501-KB Unit
Process Steam Rate	25,000 #/hr	25,000 #/hr
Electrical Power Output	2,900 kW	5,400 kW
Engine Fuel Cost, $/hr	207	236
Suppl. Fuel Cost, $/hr	27	122
Total Fuel Cost, $/hr	234	358
Other Costs, $/hr	83	115
Total Cost	317	473
Electrical Energy Revenue, $/hr	206	383
Net Operating Cost, $/hr	111	90
Cost of Steam	3.71 $/M BTu	3.01 $/M BTu

TABLE V
PERFORMANCE AND ECONOMIC COMPARISON

CASE B UTILITY OWNER SELLS STEAM

	2 Basic 501-KB Units		1 DFC 501-KB Unit	
Process Steam Rate	50,000 #/hr	0 #/hr	50,000 #/hr	0 #/hr
Electrical Output	5800 kW	5800 kW	5400 kW	5400 kW
Engine Fuel Cost, $/hr	414	414	224	236
Suppl. Fuel Cost, $/hr	54	0	244	0
Total Fuel Cost, $/hr	468	414	468	236
Other Costs, $/hr	149	149	107	107
Total Cost	617	563	575	333
Steam Sales Revenue, $/hr	331	0	331	0
Net Operating Cost, $/hr	286	563	244	333
Cost of Electrical Energy, $/kW	.0491	.0971	.0452	.0617

TABLE VI
PERFORMANCE AND ECONOMIC COMPARISON

CASE C THIRD PARTY OWNER SELLS ELECTRICAL ENERGY AND STEAM

	1 Basic 501-KB Unit	1 DFC 501-KB Unit
Process Steam Rate	25,000 #/hr	25,000 #/hr
Electrical Power Output	2,090 kW	5,400 kW
Engine Fuel Cost, $/hr	207	236
Suppl. Fuel Cost, $/hr	27	122
Total Fuel Cost, $/hr	234	358
Other Costs, $/hr	83	115
Total Cost	317	473
Electrical Energy Revenue, $/hr	206	383
Steam Sales Revenue, $/hr	166	166
Total Revenue, $/hr	372	549
Net Income Before Taxes, $/hr	55	76
Annual Net Income Before Taxes $	462,000	638,400

proposition. The attractiveness is enhanced by the application of the Dual-Fluid Cycle engine.

SPECIFIC INSTALLATION

Santa Clara Cogeneration Plant No. 1

On December 17, 1980, the City of Santa Clara, California passed an historical milestone with the dedication of its first cogeneration plant. In the works for nearly four years, the Santa Clara Cogeneration Plant No. 1 represents the first phase of the City's plan to develop its own electrical generation facilities and to provide a significant contribution to national goals for the conservation of natural resources and the achievement of energy independence. The plant became operational in September, 1981 after extensive shakedown and preliminary operational testing phases were completed.

Cogeneration Plant No. 1, shown in Fig. 9, consists of two gas-fired Allison 501-KB combustion

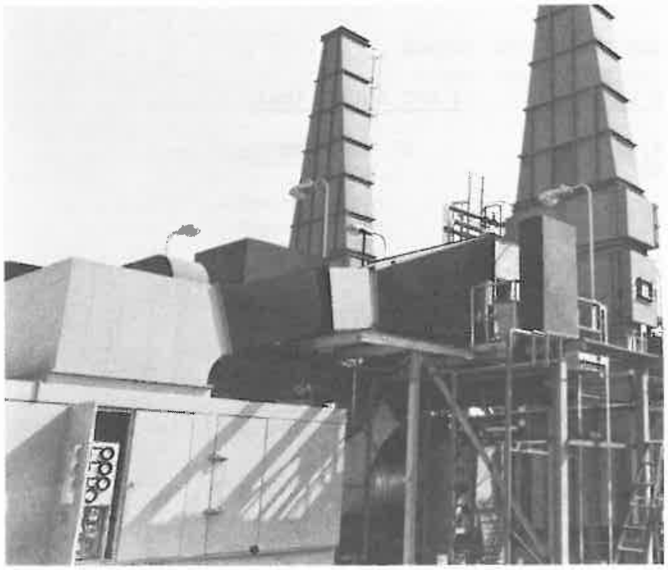


Fig. 9 Santa Clara Cogeneration Plant #1.

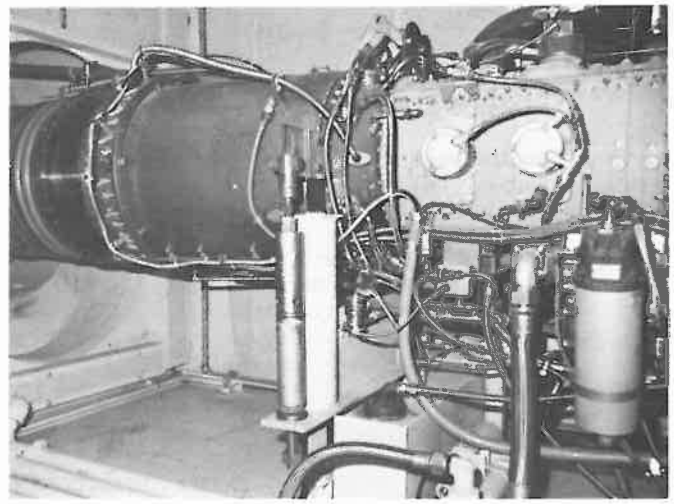


Fig. 10 Allison 501-KB engine in Santa Clara Cogeneration Plant #1.

turbine generator units with a total rated capacity of 5800 kW. One of the installed engines is shown in Fig. 10. The exhaust or "waste" heat from the turbines produces 39,000 lb/hr (17,484 kg/hr) of process steam. Supplemental firing to these two base load units has been installed to boost the process steam output to 65,000 lb/hr (29,484 kg/hr).

The plant was constructed for the purpose of gaining significant increases in the efficiency with which nonrenewable fuel resources are used. It provides efficient delivery of energy services to the Santa Clara community in the following ways:

- o Electric power is generated at a cost below that of power purchased from the Pacific Gas and Electric Company, thus the citizens of Santa Clara will benefit by reduced electrical rates.
- o The cost of steam purchased by the steam user is less than it would cost for the user to generate the process steam.
- o The amount of fossil fuel (natural gas or oil) required to generate electric power for the City and steam for the process plant is much less than the amount required if each function were performed separately.
- o The conservation of nonrenewable fossil fuels serves both local and national goals.
- o Santa Clara is a step closer to energy self-sufficiency with less reliance on costly purchased electrical power.
- o Community air pollution is reduced.
- o The technology and experience gained from this project provides a foundation upon which other energy saving cogeneration projects may be developed with the city.

Provisions were made in the plant planning for the addition of a third similar gas turbine generator which would boost the plant output to 8700 kW and the base load steam output to 58,560 lb/hr (26,563 kg/hr). Negotiations are underway to provide a DFC 501-KB generation unit as the third element of the plant.

This addition will increase the plant output to 11,200 kW. This third unit will be capable of simultaneously developing 5400 kW of electrical power with a 40 percent increase in electric generating efficiency and producing an additional 24,000 lb/hr (10,886 kg/hr) of process steam. It will also be able to produce in excess of 34,000 lb/hr (15,422 kg/hr) of process steam at a power output of 2900 kW. It will provide a greatly increased flexibility in meeting both city electrical and process steam demands. It will also provide much improved overall plant reliability/availability because any one unit can be down for maintenance or repairs and full process steam demand can be met by the remaining two units. Effective NO_x control will be provided through steam injection.

It is not possible to compare directly the resultant electrical energy costs for the DFC unit operating at Santa Clara with the projected cost given in Table V, because of differences in the debt structure (Santa Clara uses 20 year, 12% municipal bond financing), interim replacement, insurance, general and administrative, and operation and maintenance costs, and steam pricing. An analysis was made using the same steam price and the same percentage fixed and operating costs except for financing. The result for the DFC unit producing 5400 kW and 50,000 lb/hr (22,680 kg/hr) of process steam was a cost of power of \$.0360 per kWhr compared to \$.0348 per kWhr for the two basic units producing 5800 kW and 50,000 lb/hr (22,680 kg/hr) of steam. Corresponding costs given in Table V are .0452 per kWhr and \$.0491 per KWhr. (In the analyses made by the City a lower capital cost was used for the basic units, not accounting for A-E and site work costs, which accounts for the different relative unit power costs.)

The City of Santa Clara has projected the cost to the City of electrical power generated in their Cogeneration Plant No. 1 through 1997 and compared this cost to the price of available power projected by the Pacific Gas and Electric Co. (PG&E), the local major utility, through the same time period. This comparison is shown in Fig. 11. It anticipates the DFC unit coming on the line in 1984, and clearly illustrates the savings to the City accruing from cogeneration installation.

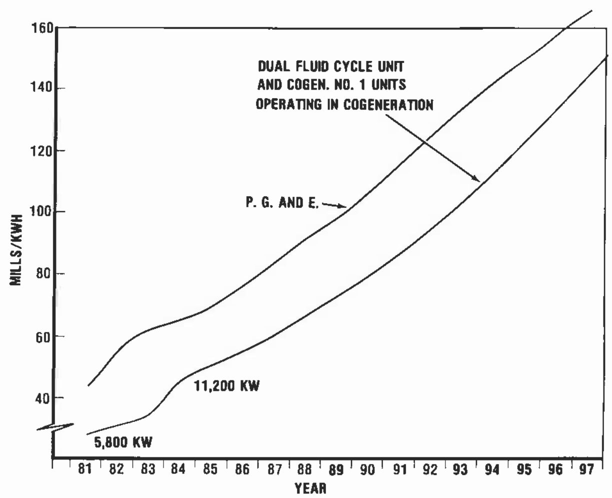


Fig. 11 Projected cost of power, Santa Clara Cogeneration Plant #1.

CONCLUDING REMARKS

The technological advances embodied in the Cheng Dual-Fluid Cycle gas turbine engine have been briefly described, and its advantages in cogeneration applications pointed out. These advantages include the high efficiency and power increases in electrical power generation, as illustrated by examples of plant economics, and its flexibility in accommodating to load shift dictated by changes in electrical power and process steam demands. This advanced cycle engine in cogeneration applications will contribute significantly to the effective practice of energy conservation in the real sense of the word, that being the careful and judicious use of energy resources in the most efficient manner.

REFERENCES

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3 "Control System for DFC™ and Operating Domain for Cogeneration," U.S. Patent #4,297,841.

4 "Steam Output Control System," U.S. Patent application #175,287, pending.