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Energy
CONSERVATION

WARE SHOALS COGENERATION

Final Technical Report

January 31, 1984

Work Performed Under Contract No. FC01-79CS40278

Riegel Textile Corporation
Ware Shoals, South Carolina

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RIEGEL TEXTILE CORPORATION

FINAL TECHNICAL REPORT

I. Introduction

Riegel Textile Corporation, headquartered in Greenville, South Carolina, operates a weaving, dyeing, and finishing plant in Ware Shoals, South Carolina in which substantial quantities of low-pressure steam are required for processing woven and knit fabrics. Steam is also used in the manufacture of chemicals and for space heating.

Riegel has operated a cogeneration system at Ware Shoals since the early 1930's by generating steam at 225 PSIG, 525°F with coal-fired boilers, and running this steam through a 2,000 KW turbine/generator exhausting steam at 45 PSIG, 370°F. Both 225 and 45 PSIG steam are used in process.

In September of 1979, Riegel signed a cooperative cost sharing agreement with the Department of Energy to design, purchase, install, and operate a new cogeneration system in which a new turbine/generator unit exhausts steam at 225°PSIG. The project is an advancement of cogeneration in the textile industry, and will demonstrate the feasibility and economic attractiveness of cogeneration in textile and other industries that use substantial quantities of relatively low pressure process steam, generated with an abundant national energy resource -- coal.

II. Background

Riegel constructed the powerhouse in the early 1920's to produce steam and electricity. Boilers No. 5 and No. 7 were installed in 1942 and 1950 respectively to replace the then existing stoker boilers. No. 5 and NO. 7 are both pulverized coal-fired boilers. Both are rated for 225 PSIG, 520°F at 85,000 #/hr. and 135,000 #/hr. respectively. Approximately 40 percent of condensate is returned to the boilers. Mechanical dust collectors and an existing Research-Cottrell Electrostatic Precipitator provides particulate removal.

Three steam turbine generators, two condensing units (3,000 KW; 2,000 KW) and one back-pressure unit (2,000 KW; 225 PSIG to 45 PSIG) were installed at the powerhouse in the 1920's and 1930's.

Mill expansions encompassed the boiler house over the years and this restricted the available space for the new boiler and turbine/generator installation to the existing powerhouse. This created a special problem in phasing the installation to keep the powerhouse in operation during construction.

Permitting was a concern considering the possible impact of the Clean Air Act -- Prevention of Significant Deterioration Requirements, on the construction schedule. However, the steam load was not being increased and Riegel agreed to a new state permit limiting the BTU input to existing levels which, in effect leaves an existing boiler as a standby unit. Limiting the BTU input allowed timely permitting of the project.

III. Project Description

The project was accomplished in three phases: (1) Design, (2) Fabrication and installation, and (3) Demonstration. Conceptual design, major equipment specifications, detailed design and construction specifications were done by Chas. T. Main, Inc., engineering consultants located in Charlotte, North Carolina. Purchase of major equipment items, construction services, and construction project management was handled by Riegel's Corporate Engineering office with assistance from Chas. T. Main in evaluating competitive bids and clarifying technical points on an as-needed basis.

Riegel's steam plant had a very limited amount of space available for expansion. Consequently, the new boiler was erected between two existing, operating boilers in a space made available by demolition and removal of two small retired stoker-fired boilers. Maintaining structural integrity in the old building was also a prime design consideration. Addition of the feedwater heater was instrumental in reducing the size of the fire box and boiler to a size compatible with the available space. For the same reason, the F.D. and I.D. fans, mechanical dust collector, and air preheater were mounted on a concrete deck elevated above the existing boiler house roof. The F. D. fan inlet was designed to pull air from inside the top of the building, which should result in a small increase in efficiency.

The new turbine was erected on a modified foundation formerly constructed for the 2,000 KW condensing turbine which was demolished and removed. Lack of space for a new generator breaker cubicle resulted in a purchase order to Westinghouse for modification of a new 1,200 amp breaker to a 1,500 amp rating. This breaker was installed in an existing cubicle that formerly contained a 1,200 amp breaker.

The new system requires more extensive water treatment due to higher pressure and temperatures than previously required. Although river and ground water in the area is of good quality relative to other areas, makeup water still contains 10 to 12 ppm silica. Also, due to the nature of the water distribution system from the city water plant and city, the plant water contains substantial quantities of chlorine. As a result, a carbon column and demineralizer to provide makeup for the new system was installed. Demineralized water is also used for boiler attemperation. Major equipment items are listed in Table I.

The demonstration phase began with commercial operation of the system and ended October 3, 1983. During this period, the system was closely monitored as to actual steam and electrical production, individual equipment and system efficiencies, operating cost, reliability, and any problems uniquely associated with a cogeneration system. Both the site and relevant data were open to inspection and review by interested parties.

TABLE I

MAJOR EQUIPMENT

1. Boiler - Riley Stoker Corporation, rated at 135,000 lb./hr., 900 PSIG, 825°F with associated F.D. and I.D. fans, pulverizers, coal scales and feeders, air preheater, mechanical dust collector, combustion and feedwater controls. Fuel is pulverized coal with #2 fuel oil as backup.
2. Turbine - Turbodyne Corporation 5,300 RPM turbine sized for 135,000 lb./hr., 850 PSIG, 825°F steam in, exhausting at 225 PSIG, 570°F with electro-hydraulic speed and back-pressure control.
3. Generator - Electric Machinery unit, 4,237 KW, 2400 volts, 1,800 RPM, .8 power factor.
4. Demineralizer - Total Water Treatment System with carbon column, and two trains of two step units followed by a mixed bed polishing unit. Rated at 300 gallons per minute, .01 ppm silica and .06 ppm sodium maximum outlet guarantee.
5. Boiler feed pumps - Ingersoll-Rand Model 3X10DH-7 stage pumps, 1,081 PSIG, 340 GPM, 3,600 RPM with 400 HP Louis Allis energy efficient motors.

IV. Technical Summary

Technical Status Reports were issued to DOE up through February 1, 1982, by which time the boiler was on-line and the turbine/generator had been brought up to speed. Problems experienced were as follows:

1. Insufficient makeup water pressure to deaerator due to the pressure drop across the DI system: It was anticipated that this problem might exist as calculations indicated marginal pressure availability at full load during periods when demand on the water system was heavy. A booster pump was installed at the discharge of the DI system and the pressure problem was eliminated.

2. High boiler exit flue gas temperature at loads above 80% of MCR and resulting loss of efficiency: Upon realization of this problem, we were asked by Riley Stoker to limit boiler loading to a maximum of 105,000 lb./hr. until an additional baffle could be installed in the generating section of the boiler. We operated accordingly until the first week of July of 1982, at which time we were able to shut the boiler down long enough for this baffle to be installed. Installation of the baffle satisfactorily resolved this problem.

3. Feedwater heater performance: Initial data indicated that the feedwater heater was operating way below design

criteria. However, it was discovered that a temperature transmitter was reading approximately 50°F low. After correction of this problem, it was found that design feedwater temperature was achieved at lower loads, but was still approximately 25°F off. It has been determined that this is due to our inability to provide the 225 PSIG, 570°F steam to the feedwater heater as specified during periods when one of the older boilers is on-line. Although originally designed to meet these conditions, the boilers now operate at 250 PSIG, 520°F. The new boiler was consequently set-up to operate with a feedwater temperature of 359°F.

4. Problems associated with putting the generator on line: Investigation revealed wiring problems in both the Westinghouse switchgear and in the generator terminal box by Turbodyne/Electric Mach. Upon correction of these problems, the generator was successfully placed on-line. Two additional problems developed after placing the turbine/generator on-line:

   a. The turbine exhaust end seal failed on two occasions -- May and November of 1982. After the first failure, the unit was shipped back to Turbodyne for repair and was repaired as originally built, with rings shrunk onto the shaft. After the second failure in November, Turbodyne machined the rings as an integral part of the shaft. There have been no problems since that date.

b. It appeared that the system was not meeting the performance guarantees at design conditions, and exhaust steam temperature was high. Despite several previous checks, it was eventually determined that the main steam transmitter was incorrecly calibrated and the generator KW meter was reading 10% low under peak conditions. Correction of these items resulted in satisfactory determination that the system did meet the performance guarantees.

V. Project Cost

ITEM	COST
Boiler & Auxiliaries	$2,844,750
Turbine/Generator	878,250
Demineralizer	290,000
Boiler Feed Pumps	117,400
Miscellaneous Equipment	481,200
Demolition	191,100
Boiler Foundation	139,100
Boiler Erection	710,400
Other Construction Contracts	1,071,800
Engineering	476,000
TOTAL PROJECT COST	**$7,200,000**

VI. Operating Cost

A comparison of average monthly operating costs, including parts, supplies, and repair labor, shows a 68% increase for the twenty-month period that the new equipment has been on-line as compared to the thirteen-month period prior to start-up of the new equipment. Obviously a certain percentage of this can be attributed to inflation of both labor and parts. It is also significant to note that three additional supervisory personnel were added to the work force shortly after start-up of the new equipment. The additional supervision would probably have been added in any case.

The increase includes the addition of two people in the area of water treatment. These personnel operate the demineralizer system and assist with boiler water analysis and chemical treatment. This additional operating cost can be directly associated with the new equipment. Increased chemical costs, caustic and acid, for regeneration of the demineralizer system can also be attributed directly to operation of the new boiler and turbine.

Of the remaining additional cost, a large part can be attributed to the increased complexity of the new equipment. The majority of the controls on the new equipment are electronic as compared with pneumatic on the older equipment. The new equipment includes more monitoring devices such as transmitters, controllers, indicators, etc., than were included on the older equipment and, as a result, require more attention from maintenance personnel.

Some of the additional cost can also be attributed to working "bugs" out of the new equipment during the initial operating period. We are not able to break this cost down, but do expect to see some decrease in cost attributable to this area in the future.

VII. Savings

A. Fuel

For the twelve-month period ending 10/3/81, fuel costs were $2.02/million BTU's. During this period, all of the steam was generated by the older existing boilers. For the twelve-month period ending 10/2/82, fuel costs were $2.25/million BTU's. During this period, 50.8% of the total steam was generated by the new high-pressure boiler. For the eleven-month period ending 9/3/83, fuel costs were $1.90/million BTU's, during which period the new boiler carried 81% of the total steam load.

The high cost during the twelve-month period ending 10/2/82 can be attributed to several factors. During this period, substantial amounts of fuel were burned in boiling out the new boiler and preparing for start-ups. As noted previously, the new boiler operated for five months at reduced loads and lower efficiency prior to an additional baffle being installed in the generating section. Unusually large amounts of oil were also burned during this period due to coal quality problems. This problem was corrected after implementation of a comprehensive coal testing program with penalty/premium clauses for suppliers.

For purposes of calculating the R.O.I., the difference in fuel costs between the period ending 10/3/81 and the period ending 9/3/83 have been used. Fuel costs are comparable during this period.

STEAM
(LBS. X 1,000)

*QUARTER	TOTAL USAGE	**BOILER #8	#8% OF TOTAL
1982 - 1ST	178,266	58,336	32.7
1982 - 2ND	149,957	102,625	68.4
1982 - 3RD	171,359	160,601	93.7
1982 - 4TH	210,605	164,113	77.9
TOTAL	**710,187**	**485,675**	**68.4**
1983 - 1ST	213,564	146,098	68.4
1983 - 2ND	182,059	154,247	84.7
1983 - 3RD	151,020	150,960	99.9
TOTAL	**546,643**	**451,305**	**82.6**

**New unit.

*Based on calendar year.

B. Electrical

Electrical savings were originally based on generating an average of 3,900 KW or 23,400,000 KWH annually. However, as a result of reduced production in the plant during the past two years and other energy conservation projects being implemented, steam demand has been substantially reduced. Based on production for the first nine months of 1983, annual production from the new generator is 15,500,000 KWH. This will increase as production activity picks up. Based on fuel and the additional cost of generating steam associated with the new system, our costs for generating electricity is calculated to be 1.6 cents per KWH. This is based on the fact that all other costs associated with producing steam and electricity would be incurred whether the new system was in place or not. The cost per KWH includes all associated costs.

To calculate savings, several utility bills were re-calculated with the KWH's produced by the new generator added to the utility billing to determine what the difference would have been. Based on the spot checks made, it is estimated that $40,000 per month is a very reasonable figure. However, it should be noted that several factors complicate the situation to the point where it is virtually impossible to reach an exact figure.

Examples are:

1. The utility rate schedule is graduated such that the more KWH produced, the cheaper the rate per KWH. Where Riegel falls on this rate schedule is affected by a widely

fluctuating plant KW load, the amount of KWH's generated by Riegel's hydro-electric plant (production here is solely dependent on rainfall and river flow), and occasional operation of a condensing turbine/generator unit used to assist in holding demand and stabilizing boiler loads.

2. Varying power factor penalties resulting from problems with capacitor switching devices in recent months.

3. Wide fluctuations in plant production steam demand. The amount of KWH's produced by the back-pressure turbine/generator is dictated by plant production requirements.

4. KW demand savings were included in the original proposals and are included here, as realized to date. However, it is important to note that this savings can easily be lost if generating capacity is off-line due to trips during peak demand periods. Prior to start-up of the new system, Riegel's billing demand was 9,440 KW. It is presently 5,550 KW, or a net reduction of 3,890 KW to date.

POWER GENERATION

*QUARTER	TOTAL USAGE (KWH x 1,000)	IN-PLANT GENERATION (KWH x 1,000)	IN-PLANT % TOTAL Production	**GENERATED #4 (KWH x 1,000)	#4 % TOTAL Production	PURCHASED KWH	BILLING DEMAND (KW)
1981 - 1ST	15,888.5	6,261.3	39.4	0	0	9,627.2	
1981 - 2ND	17,819.7	5,714.1	32.1	0	0	12,105.6	
1981 - 3RD	17,185.7	4,030.7	23.5	0	0	13,155.0	
1981 - 4TH	11,759.9	2,603.9	22.1	0	0	9,192.0	
TOTAL	**62,689.8**	**18,610.0**	**29.7**	**0**	**0**	**44,079.8**	
1982 - 1ST	13,980.6	6,497.0	46.5	607.7	4.4	7,483.6	9440
1982 - 2ND	16,573.0	8,739.4	52.7	2,386.8	14.4	7,833.6	9440
1982 - 3RD	17,222.6	8,009.8	46.5	3,881.0	22.5	9,212.8	9760
1982 - 4TH	11,174.3	8,775.9	73.5	3,229.9	28.8	2,398.4	9760
TOTAL	**58,950.5**	**32,022.1**	**54.3**	**10,098.4**	**17.1**	**26,928.4**	
1983 - 1ST	10,984.0	8,662.4	78.9	3,729.8	34.0	2,321.6	5440
1983 - 2ND	12,078.2	10,912.4	90.4	3,966.9	32.8	1,165.8	9110
1983 - 3RD	11,373.4	7,649.2	67.3	3,918.4	34.5	3,724.2	5550
TOTAL	**34,435.6**	**27,224.0**	**79.1**	**11,615.1**	**33.7**	**7,711.6**	

** New Unit

VIII. Return on Investment

A. Savings:

1.	Power produced in lieu of purchased from utility 12 Months x $40,000	$480,000
2.	Power sold	$ 20,000
3.	KW Demand Reduction	$115,766
4.	Fuel (Based on Equal Steam Production in 1981 and 1983) $1,806,000 - $1,563,219	$242,781
	Savings	$858,547

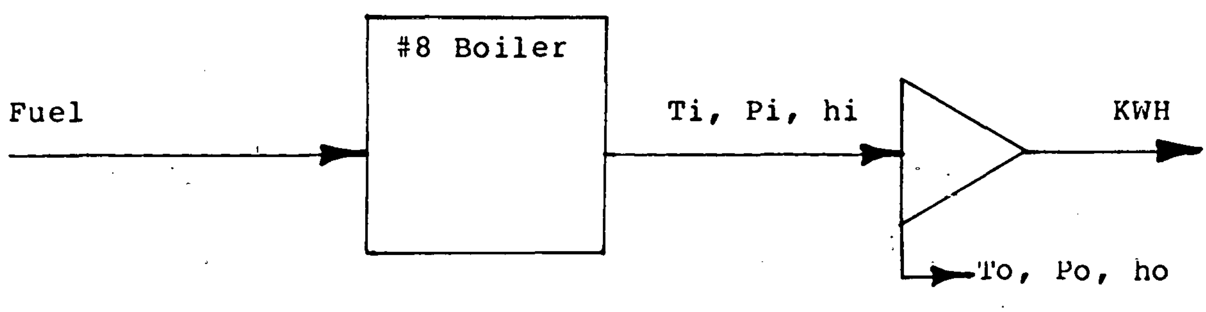
B. Cost:

1.	Cost of Generating Power* $0.016/KWH x 15,500,000 KWH =	$248,000

*See cost/KWH determination.

TOTAL SAVINGS **$610,547**

COST/KWH DETERMINATION



Where:	Ti	=	830°F	To	=	525° F
	Pi	=	910 PSIG	Po	=	225 PSIG
	hi	=	1411 BTU/#	ho	=	1276 BTU/#

$$\frac{\text{Cost/million BTU's} \times \text{lbs. steam produced} \frac{(hi-ho)}{hi}}{\text{BTU's per lb. of steam/KWH}}$$

#'s Steam Produced (3 periods)	=	164,832,000
Cost/1,000# Steam*	=	$4.45
Cost/million BTU's*	=	$3.15
KWH Produced (3 periods)	=	4,453,400 KWH

Cost/KWH = $0.016/KWH

*Average cost for 12 periods, includes all associated costs.

C. Project Cost

Item	Cost
Boiler & Auxialiaries	$2,844,750
Turbine/Generator	878,250
Demineralizer	290,000
Boiler Feed Pumps	117,400
Miscellaneous Equipment	481,200
Demolition	191,100
Boiler Foundation	139,100
Boiler Erection	710,400
Other Construction Contracts	1,071,800
Engineering	476,000
Total Project Cost	**$7,200,000**

C. ROI

Return on investment (ROI) can be considered from two different perspectives. The first is to use incremental capital cost in which it is assumed that a retired boiler or production expansion will require purchase of a new boiler rated at process steam pressure and base the ROI on the incremental cost only of going to a topping system. The second is to assume that an existing useful steam generator will be torn out and replaced with a topping system, in which case the total capital cost is used.

Estimating a capital cost of \$4.7 million for a 225 PSIG boiler, a simple ROI can be calculated as follows:

1. Incremental Cost

Cost 900 PSIG system	\$7,200,000
Cost 225 PSIG Unit (estimated)	\$4,700,000
	\$2,500,000

$$\text{ROI} = \frac{610{,}547}{2{,}500{,}000} = 24.4\%$$

2. Total Cost

$$\text{ROI} = \frac{610{,}547}{7{,}200{,}000} = 8.5\%$$

IX. Conclusion

The completed cogeneration project will annually generate a minimum 15,500,000 KWH that would normally have to be purchased from the local utility. This has five beneficial effects. First, power from the cogeneration project will be produced for 3,859 BTU/KWH and the local utilities production rate is 9,743 BTU/KWH for a net energy savings of 6,154 BTU/KWH. Second, 15,500,000 KWH becomes available for other demand areas. Third, utility demand requirements are reduced by 3,890 KW. Fourth, annual national fuel consumption is reduced. Fifth, annual energy costs for Riegel are reduced.

The United States Commerce Department, Census of Manufacturers states that for 1976, the textile industry used 28,509.3 million KWH of which 483.7 million KWH or 1.6% was self-generated.

By utilization of cogeneration throughout the textile industry, potentially 10,933.9 million KWH could be generated at a lower BTU/KWH. This would result in an annual national savings of 58,288,536 million BTU'S or 9.3 million barrels of oil equivalent.

The cogeneration cycle of topping high pressure steam is applicable to many industries. However, it must be emphasized that because of the high capital cost of a steam generator replacement, economic justification may not always exist. If an incremental expansion or replacement of steam generation equipment is planned, then the economic justification for cogeneration can be very attractive. A look at purchased power cost increases versus coal price increases over the past few years and as projected for the future will increase the attractiveness of cogeneration in almost all cases, and selling power under the Public Utilities Regulatory Policy Act to the local utility may also improve the effectiveness of cogeneration in some cases.