APPLICATION OF BSF TECHNOLOGIES CTC3 TO A PHOSPHATE FERTILIZER COMPLEX

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I. OVERVIEW:

During the past two years the BSF Team has been researching a new cogeneration technology for the phosphate industry. This technology was developed in conjunction with the team's effort to optimize additional energy recoveries from phosphate fertilizer complexes and integrate this energy recovery with enhanced electric power generation. Recent trends in the utility power industry have brought forth an opportunity to enhance energy recoveries at fertilizer complexes and integrate present utility power generation planning or expand self-generation at these locations.

In the last decade the recovery of energy as electric power has been a major contributor to phosphate fertilizer industry profits. Essentially all facilities produce sufficient electric power to supply complex requirements, eliminating or minimizing the electric power bill. The recovery of additional energy for sales to the utility industry has, for the most part, been uneconomical due to the low value (less than $0.025/KWH) attributed to the fuel, operating and maintenance components of the utility's avoided cost. With long term guarantees of power production and reliability, additional capacity credits are available, and power sold to the utility would be worth approximately $0.045 to $0.06/KWH, increasing the levels of economic energy recovery and revenue to the fertilizer industry. However, based on the cyclic nature of the industry and the utility industry's need for long term guaranteed capacity contracts, most fertilizer complexes have been unable to attain this extra revenue and optimize energy recovery in the plants.

During this same period many utilities have moved from the traditional large power (+500 MW) generating plants (coal, oil, nuclear) to combined cycle gas turbine systems. Under Florida's generation expansion plan, all upcoming units for the early 1990's will be combustion turbine combined cycle units (CTC2). The Florida utilities are currently expected to install six new combined cycle units in the early 1990's producing approximately 2,400 megawatts of additional capacity. These units will be used initially as peaking gas turbines and then converted as required to base loaded, combined cycle units at a future date.

BSF Technologies has developed a novel approach to couple the additional energy recovery available in a phosphate fertilizer complex with the utility trend towards gas turbine generating facilities, providing an economic route to increase energy recovery and fertilizer industry revenues. This paper presents the basic concepts of the BSF Technologies CTC3 - Combustion Turbine, Combined Cycle Cogeneration system for application in a phosphate fertilizer complex.

II. BACKGROUND:

PHOSPHATE FERTILIZER COMPLEX:

Prior to the 1973 oil embargo, all of the available energy from the production of sulfuric acid in a fertilizer complex was recovered in the form of steam to power various turbine drives and provide steam for the fertilizer processes. With electricity during this period at approximately $0.01/KWH, there was no immediate motivation for the industry to consider utilizing the steam for the production of electricity. While some companies such as Gardinier, Inc., Tampa, Florida, had experimented with small (<5MW) turbine generator sets in the 1950's and 1960's, no one in the industry had looked at a serious recovery of all the available steam with conversion to power under a cogeneration concept.

The rising cost of electrical energy in the late 1970's and early 1980's and the low selling price of phosphate fertilizer, stimulated renewed evaluation of energy recovery. With the advent of the Public Utilities Regulatory Policies Act (PURPA) of 1978, the industry began serious consideration to convert all of the steam at each facility to electric power on a scale large enough to supply the entire electric requirements of the complex. The PURPA laws of 1978 required the electric utility companies to interconnect with cogeneration facilities and pay a fair price for any exported power based on the utility's avoided cost. The anticipation of electric costs rising to three or four times the levels of the pre-oil embargo days required phosphate fertilizer complexes to begin technical consideration of energy recovery for electric power generation. Attached as EXHIBIT I is a summary of the units installed since 1958 with their approximate KW capacity.

Based on the low avoided energy cost offerings of most of the electric utilities in Florida, very few of the new fertilizer cogeneration projects were developed to their maximum potential capacity. Since sales of the excess electricity could not offset the additional capital investment required to produce more steam, optimization of energy recovery reached a barrier limit. In other words, generating capacity beyond one's own plant demand did not make good economic sense. In addition, the long term (+10 year) capacity contracts required by the utilities to sell all of the power was a barrier to full energy recoveries in the complex. These long term contract requirements, coupled with the cyclic demand and economic trends in the industry, made selection of a capacity credit for exported power nearly impossible.

ELECTRIC UTILITY INDUSTRY:

Prior to the oil embargo of 1973, most of the utility companies in the United States generated a majority of their electric power from cheap oil, nuclear or coal-fired facilities. Subsequent concerns about nuclear generated power after the Three Mile Island event all but eliminated future consideration for this option. With the rising cost of oil, many utilities converted to burning coal. Subsequent concerns about air pollution, acid rain, and the high cost of environmental control equipment caused many of the utilities to reconsider their future expansions in this area. These items, in conjunction with the general concerns for permitting large (+500 MW) capital intensive facilities caused the utilities in the late 1970's and early 1980's to begin searching for an alternative solution to power generation.

Some utility companies with high growth rates similar to Florida Power & Light Company (FP&L) in South Florida had experimented in the mid 1970's with utilizing gas turbine peakers which could be designed, built, and become operational in less than one-half the construction time of a traditional large generating facility. These units had a low unit capital cost ($/MW), but had the disadvantage of high operating costs resultant from a low thermal efficiency. Attached as Exhibit II is a summary of the typical utility thermal efficiencies and heat rates for various forms of power generation, including the combustion turbine combined cycle (CTC2) concept. For the simple cycle exhaust gas combustion turbine, thermal efficiencies in the 15% to 25% range, with heat rates in excess of 15,000 BTU's per KWH were typical. Since rapid growth utilities like FP&L had few options to meet their expanding system demand, many of these units designed as peaking generators were installed.

Realizing the low efficiency of the simple cycle combustion turbine (SCCT), the power generation industry began researching a more efficient way to operate gas turbine systems and recover the large volumes of waste heat exhausted from the units. The concept of a combustion turbine combined cycle unit (CTC2) began appearing in the mid 1970's. The basic concept was to install a heat recovery steam generator (HRSG) on the exhaust gas outlet from the combustion turbine and produce steam for powering a steam turbine.

Recent improvements in gas turbine technology such as regeneration, steam injection, unitized packaging, and supplemental firing of the heat recovery steam generator (HRSG's) have begun to optimize the combined cycle (CTC2) process and make it competitive with other forms of utility power generation. Based on the combined cycle system, most utilities are presently projecting new generation expansion plans utilizing this technology. As indicated above, all of the planned generation expansions for the state of Florida in the early 1990's is expected to be from combustion turbine, combined cycle units. These units can be installed initially as front-end gas turbine peakers, and converted to combined cycle by the addition of a heat recovery steam generator (HRSG) and steam turbine when the system demand increases and there is a larger need for base-loaded units. Since the combined cycle (CTC2) technology is competitive on an efficiency, capital cost and heat rate basis with traditional coal, oil or nuclear generation, the combined cycle system is the likely unit to be installed by most electric utility companies in the early 1990's.

III. <u>COMBUSTION TURBINE COMBINED CYCLE COGENERATION (CTC3)</u>:

With this historical background, BSF Technologies began searching in 1988 for a method to integrate the combined cycle unit (CTC2) developed for electric utility companies with the concept of additional energy recovery and cogenerated electricity in a phosphate fertilizer complex. This lead to the development of the CTC3 (Combustion Turbine Combined Cycle Cogeneration) technology. The BSF Team in it's development research of the CTC3 concept set forth the following <u>three</u> key questions as a basis for the study:

1. Do the recent utility trends to the smaller combined cycle CTC2 units and cogeneration at a phosphate fertilizer complex have any common parameters for integration?
2. Could the overall efficiency, heat rate, unit capital cost, and operating cost of the present utility combined cycle system be improved by integration with a phosphate fertilizer cogeneration unit?
3. How could the phosphate fertilizer complex economically recover additional energy available in the process for generating more electric power?

The development in 1989 of the combustion turbine combined cycle cogeneration (CTC3) concept by BSF Technologies brought forth an opportunity to re-evaluate energy recoveries in a phosphate fertilizer complex. Attached as Exhibit III is the basic Cycle Diagram for the Combustion Turbine Combined Cycle Cogeneration Unit (CTC3).

The two basic components of the CTC3 system are the acid plant cogeneration system seen on the left side of the cycle diagram, and the utility Combustion Turbine/HRSG unit seen on the right side of the diagram. The acid plant cogeneration system consists of a high pressure steam boiler at the sulfuric acid plant supplying steam to a typical condensing/extraction steam turbine. The steam turbine can be energy enhanced through the admission of additional steam from other sources such as older lower pressure sulfuric acid plants. Extractions for process at the 50# saturated pressure level and also at higher pressure levels are available from the turbine. This diagram shows a typical 900#, 900^{O}F steam turbine unit with a 250#, 750^{O}F admission and a 50# saturated extraction to the phosphoric acid plant. This diagram also shows a 450# uncontrolled extraction that could be used for a process such as making super acid. These extractions back to the process are the fundamental cascaded energy requirements of cogeneration. By producing electric power from the available high pressure steam first and recovering the lower pressure steam for the process, a true cogeneration unit is created.

Present day range on these cogeneration units is typically from 35 to 60 MW. The energy produced by these units is basically used in the facilities with additional generation exported to the grid as shown in this diagram.

The typical combustion turbine facilities used by the electric utility industry is shown on the right hand side of the cycle diagram. The upper portion shows the basic steam injected gas-fired combustion turbine connected to a standard utility electric generator. The lower portion shows the heat recovery steam generator (HRSG) feed from the 800-1100°F exhaust gas off of the combustion turbine. Most utilities typically use a dual pressure HRSG, which can be supplementally fired to increase overall combustion efficiency of the units. The typical high pressure section of the HRSG is used to feed a utility steam turbine with pressures and temperatures in the 900#, 900°F range. The low pressure portion of the HRSG produces 450 pound saturated steam that can be injected into the gas turbine for NOX control and to improve the overall efficiency of the unit.

The typical unfired ratio of power produced for a steam turbine is 1/5 the size of the power output from the gas turbine. By additional supplemental firing of the HRSG, the steam power recovery can be improved to approximately 1/3 the size of the gas turbine. Exhibit IV shows some typical gas turbines available to the utility industry for creating combined cycle units. These units range in size from 40 MW to just over 200 MW. Potential dispatch combinations of these units is shown in Exhibit V.

As you will see from Exhibit IV, the base rating on the various General Electric 5000, 6000, and 7000 gas turbines units range from a low of 30 MW to a high of 150 MW. Based on typical unfired and supplementally fired HRSG's, the total combined capacity of these units ranges from a low of 36 MW to a high of approximately 200 MW. The actual steam availability from the combined cycle HRSG's has a range of approximately 6 MW to around 50 MW. Since these numbers are nominally in the range of steam turbines typically used in the phosphate fertilizer industry, they offer an opportunity to integrate the two systems.

With the dispatch options available from Exhibit V, a utility company, IPP (Independent Power Producer), or phosphate company could integrate the front end (Gas Turbine & HRSG) of a combined cycle CTC2 unit with a typical sulfuric acid steam turbine cogeneration facility to meet varying load conditions. The shared steam turbine unit can be operated as an independent cogeneration facility or as the back end of a typical utility type combined cycle unit.

Since the electric utility industry normally installs the combustion turbine peaker unit first and converts the unit to a combined cycle base loaded unit later, by adding the HRSG and steam turbine, the integration can be timed to optimize the cogeneration steam turbine size and availability to the needs of utility peaking power or higher efficient combined cycle units. Additional power can also be produced for mining operations and/or other process load requirements by installing the front end gas turbine and HRSG to the standard cogeneration steam turbine in a phosphate fertilizer complex. Either of these options would be considered CTC3 (Combustion Turbine Combined Cycle Cogeneration) and will integrate the highest efficiency utility power generation equipment with the overall efficiencies of cogeneration.

The cycle diagram of Exhibit III also shows some additional requirements and benefits of this system. To accomplish CTC3 technology requires a large supply of gas and a utility grid of sufficient size to export electric power from the site. Since most of the large fertilizer complexes are centrally located near the transmission grids and gas supplies, they are ideally suited for this application. The area is also more suitable to heavy industrial operations such as power generation than the metropolitan area or other environmentally sensitive locations.

The CTC3 concept takes advantage of the high efficiencies of cogeneration and the latest technologies developed for the electric utility industry. The joint use steam turbine and the lower production cost of cogeneration produce both an overall lower unit capital cost ($/KW) and operating cost ($/KWH). The use of multiple fuels, common pressures and temperatures and the jointly used steam turbine provides for a cost effective and flexible operating system. Unlike the straight condensing steam turbine used by the utility companies in their CTC2 systems, the phosphate complex turbines are typically provided with process extractions and admission ports to enhance flexibility. Various alternate paths for steam flow are shown on the Cycle Diagram of Exhibit III to demonstrate some of the flexibility developed with the CTC3 technology.

IV. ADDITIONAL ENERGY RECOVERIES:

Once it was determined that an electric power generation facility could be developed to take advantage of the phosphate cogeneration concept and the utility combined cycle system, a search began for additional energy recoveries in the process.

Numerous enhancements to the steam energy recovery in a fertilizer complex have been developed over the years, but have not been implemented due to their high capital cost as a ratio to the value of exported power. Since the purchase cost of electricity is typically $0.05 - $0.06/KWH for the industry and the sale of excess "AS AVAILABLE" energy is only around $0.02/KWH, no justification could be developed for creating power in excess of the existing needs of the complex. Based on the cyclic nature of the industry, the utility and phosphate companies were unable to obtain long term capacity contracts that would improve the overall cost of exported power and justify the cost of additional energy recoveries in the complex.

The CTC3 technology now offers an alternate solution to this dilemma by using a common steam turbine for use with a utility company CTC2 system or integration of a Gas Turbine and HRSG to the fertilizer complex as an IPP (Independent Power Producer) or self-generator of additional power for mining or other loads. Attached as Exhibit VI is a list of some of the additional energy recovery areas in the fertilizer complex that, in general, have not been fully implemented because of their higher capital cost. Many of the marginal energy recoveries previously examined will need to be revisited in light of the CTC3 technology. Numerous detailed analysis and papers on this subject have been previously given before this society. One of the more comprehensive analysis was given by a member of this team.

"ENERGY RECOVERY IN PHOSPHATE FERTILIZER MANUFACTURE"
"STATE OF THE ART"
BY: LEONARD J. FRIEDMAN LAKELAND, FLORIDA
ACID ENGINEERING & CONSULTING, INC.
AICHE SPRING NATIONAL MEETING 1986, NEW ORLEANS

V. SUMMARY:

The phosphate fertilizer industry has been searching for ways to recover lower level energy in the complexes while producing additional electric power that can be valued at rates above the "As Available" avoided energy cost from most electric utility companies. Difficulties in securing long term capacity contracts to enhance the value of exported power have been created by the cyclic nature of

the phosphate industry and the electric utility companies unwillingness to deal with this risk.

The CTC3 (Combustion Turbine Combined Cycle Cogeneration) concept is an alternative to this dilemma. By providing utility companies the opportunity to site their upcoming gas turbine peakers at the phosphate fertilizer complexes, numerous opportunities for integration to combined cycle units become available. Additionally, the concept of CTC3 can be independently evaluated by the fertilizer industry as a means to produce additional power for mining operations or other benefication loads. The CTC3 technology can also be used as a means to re-evaluate the lower level energy recovery systems not yet implemented in the complex.

While the CTC3 concept appears straight forward in basic design, numerous detail analysis must be performed to evaluate it's application at any particular site. Technical parameters such as FCP (Fuel Chargeable to Power), Neff (Thermal Efficiency), Heat Rates, Incremental Capacity Cost ($/MW), Incremental Energy Cost ($/MWH), Steam Energy Valuation and many others must be considered to implement this technology properly. This paper is an attempt to summarize the overall concept of CTC3 and not to provide all of the detailed technical analysis required to implement the concept on a site specific basis.

Recent power black-outs in Central Florida with their implied demand for more efficient reserve capacity has created a need for

CTC3. The utility trend towards smaller combined cycle units makes integration with a phosphate complex possible. Additional environmental and efficiency advantages of siting these units in the industrial phosphate area creates additional opportunities for CTC3 in central Florida.

The BSF Technologies Team has been researching the concept for the past two years and have developed it to a level that a site specific technical evaluation can now be accomplished. Alternate joint ventures, IPP's and enhanced cogeneration scenarios have been examined. Detailed research with gas turbine manufacturers have been conducted and preliminary negotiations with utility companies and IPP's have occurred.

If after reviewing this technical paper you should have any questions or need any further details, please contact:

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EXHIBIT I

FLORIDA PHOSPHATE INDUSTRY
COGENERATION FACILITIES
MARCH 15, 1990

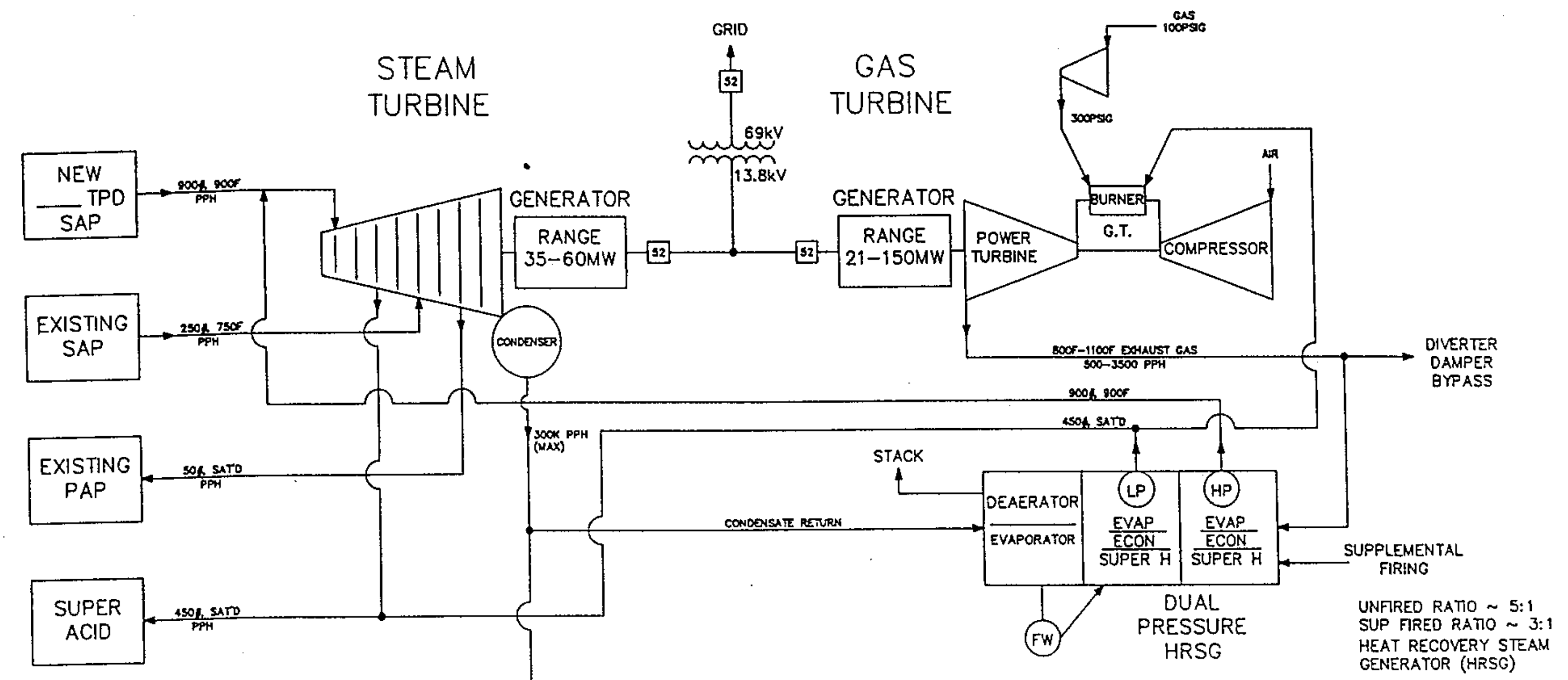
1.	AGRICO - S. PIERCE (USED)	8,000 KW	1981
2.	CF INDUSTRIES - PLANT CITY	34,485 KW	1987
3.	CONSERV - NICHOLS	13,280 KW	1982
4.	FARMLAND IND. - MULBERRY	38,160 KW	1990
5.	GARDINIER #1 - TAMPA (RETIRED)	1,500 KW NI	PRE 1958-1987
6.	GARDINIER #2 - TAMPA (RETIRED)	3,750 KW NI	PRE 1958-1988
7.	GARDINIER #3 - TAMPA	6,000 KW	1961
8.	GARDINIER #4 - TAMPA	37,800 KW	1988
9.	IMC - #1 - MULBERRY	10,000 KW	1981
10.	IMC - #2 - MULBERRY	60,000 KW	1983
11.	OCCIDENTAL #1 - LAKE CITY	14,700 KW	1980
12.	OCCIDENTAL #2 - LAKE CITY	28,000 KW	1986
13.	ROYSTER - MULBERRY	21,000 KW	1985
14.	USS AGRICHEMICALS - FT. MEADE	32,000 KW	1982
15.	W.R. GRACE	36,915 KW	1985
	TOTAL	340,340 KW	
	POTENTIAL	350 MW - 500 MW	

EXHIBIT II

TYPICAL
POWER GENERATION
THERMAL EFFICIENCIES η_{eff}
AND HEAT RATES (BTU/KWH)
MARCH 15, 1990

	GENERATION TYPE	η_{eff}	APPROX. HEAT RATES - LHV
1.	NUCLEAR POWER - STEAM	33 - 35%	10,300- 9,700 BTU/KWH
2.	COAL FIRED - STEAM	36 - 38%	9,600- 9,000 BTU/KWH
3.	OIL FIRED - STEAM	37 - 39%	8,800- 8,300 BTU/KWH
4.	GAS FIRED - STEAM	40 - 42%	8,500- 8,100 BTU/KWH
5.	COMBUSTION TURBINES	15 - 55%	+15,000- 6,000 BTU/KWH
	1. SIMPLE CYCLE (SCCT)		
	1. DUAL ENGINE OPPOSED	15 - 20%	16,000-14,000 BTU/KWH
	2. STD. SINGLE ENGINE	25 - 30%	13,000-12,000 BTU/KWH
	3. REGENERATED UNIT	30 - 35%	12,000-10,000 BTU/KWH
	4. STEAM INJECTED UNIT	35 - 40%	10,000- 9,500 BTU/KWH
	2. COMBINED CYCLE: (CTC2)		
	1. STANDARD HRSG	43 - 45%	7,500- 6,500 BTU/KWH
	2. SUPPLEMENTAL FIRED	45 - 50%	6,500- 6,000 BTU/KWH
6.	COGENERATION	50 - 80%	< 5,000 BTU/KWH
7.	CTC3	+50%	< 5,000 BTU/KWH

EXHIBIT III



NOTES:

1. GAS PIPELINE NEARBY–FLORIDA GAS TRANSMISSION
2. LARGE TRANSMISSION SUBSTATION NEARBY
   1) TECO – PEBBLEDALE
   2) FPC – BARCOLA
3. ENVIRONMENTALLY STABLE AREA FOR POWER GENERATION
4. EFFICIENCIES OF COGENERATION AND COMBINED CYCLE GAS TURBINE GENERATION
5. LOWER UNIT CAPITAL COST ($/MW)
6. LOWER UNIT PRODUCTION COST ($/MWH)
7. TRIPLE FUEL CAPABILITY: GAS, DISTILLATES, SULFUR
8. COMMON STEAM PRESSURES & TEMPERATURES
9. OPERATING FLEXIBILITY
10. COST FLEXIBLIITY

NO.	DATE	REVISION	BY	APP

BUSHEA & ASSOCIATES, INC.
REGISTERED PROFESSIONAL ENGINEERS
1003 S. COLLINS ST. PLANT CITY, FL 813-752-3049

CUSTOMER: CUSTOMER/UTILITY

SCALE: ~ | DRAW BY: CWS | DATE: 4/3/89

APPROVED BY: | JOB NO:

TITLE: BSF TECHNOLOGY
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LEONARD J. FRIEDMAN, P.E.

SHEET 1 OF 1

DRAWING NO: BA890512

EXHIBIT IV

TYPICAL UTILITY
GAS TURBINE & HRSG DATA
MARCH 15, 1990

MODEL	G.T. BASE(NOM)	UNFIRED CTC2 @ APPROX. 5:1	SUP FIRED @ APPROX. 3:1	TOTAL UNFIRED	TOTAL FIRED
GE 5001	30MW	+ 6MW	+10MW	36MW	40MW
GE 6001	40MW	+ 8MW	+13MW	48MW	53MW
GE 7001EA	85MW	+17MW	+28MW	102MW	113MW
GE 7001F	150MW	+30MW	+50MW	180MW	200MW

DATA: COURTESY OF GENERAL ELECTRIC COMPANY

EXHIBIT V

SYSTEM DISPATCH PROFILE
COMBINED CYCLE GAS TURBINE
MARCH 15, 1990

TYPE	QTY.	GT MW	UNFIRED STEAM	FIRED STEAM	TOTAL MW
G.E. 7001F	1	150MW	(1) 30MW	(2) 40MW	180 - 190
G.E. 7001EA	2	85MW	(1) 17MW	(2) 28MW	102 - 226
TOTAL		(170MW)	(3) 34MW	(4) 56MW	
G.E. 6001	3	40MW	(1) 8MW	(2) 13MW	48 - 159
TOTAL		(120MW)	(3) 16MW	(4) 21MW	
			(5) 24MW	(6) 26MW	
			(7) 29MW	(8) 34MW	
			(9) 39MW		
G.E. 5001	4	30MW	(1) 6MW	(2) 10MW	36 - 160
TOTAL		(120MW)	(3) 12MW	(4) 16MW	
			(5) 18MW	(6) 20MW	
			(7) 22MW	(8) 24MW	
			(9) 26MW	(10) 28MW	
			(11) 30MW	(12) 32MW	
			(13) 36MW	(14) 40MW	

TABLE VI

PHOSPHATE FERTILIZER COMPLEX
ADDITIONAL ENERGY RECOVERY
SYSTEM
MARCH 15, 1990

1. ACID HEAT RECOVERY SYSTEMS

2. FERTILIZER PLANT ENERGY IMPROVEMENTS

    1. ELIMINATION OF STEAM JETS

    2. AMMONIA VAPORIZATION

    3. HEMI-HYDRATE

    4. ELIMINATE STEAM DRIVES

3. OTHER SAP IMPROVEMENTS

    1. HIGHER STEAM PRESSURE DESIGNS

    2. HIGHER GAS STRENGTH DESIGNS

    3. SUCTION BLOWERS

    4. ALL ELECTRIC DRIVES

    5. LOW TEMPERATURE ECONOMIZERS

    6. LOW PRESSURE DROP DESIGNS