GER-3651D

GE Power Generation

GE Combined-Cycle Experience

Chris E. Maslak
Leroy O. Tomlinson
GE Industrial & Power Systems
Schenectady, NY

COMBINED-CYCLE EXPERIENCE

C.E. Maslak and L.O. Tomlinson
GE Industrial & Power Systems
Schenectady, NY

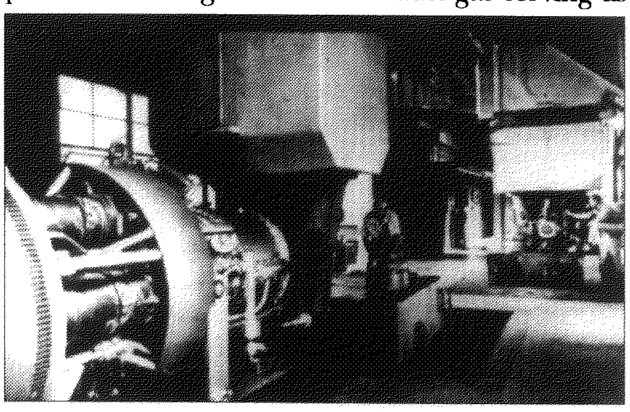
INTRODUCTION

The worldwide acceptance of steam and gas turbine combined cycles for electrical power generation is a result of the outstanding thermal efficiency, low installed cost, reliability, environmental compliance and operating flexibility that has been demonstrated by operating experience. Since 1949, GE has furnished 41,000 MW of power generation combined-cycle equipment. The continual effort by GE to improve the quality of this equipment, coupled with feedback from owners with extensive operating experience, has brought this combined-cycle equipment to its prominent status in the power generation industry.

HISTORICAL SUMMARY

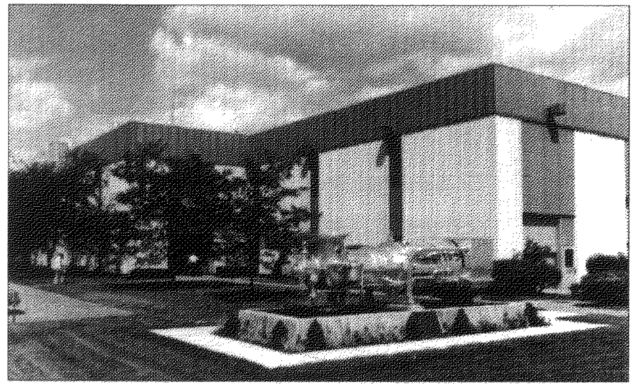
The commercial development of steam and gas turbine combined cycles has proceeded in parallel with gas turbine development. The first gas turbine installed in an electric utility in the United States was applied in a combined cycle. This was a 3.5- MW gas turbine that used the energy from the exhaust gas to heat feedwater for a 35-MW conventional steam unit. This system entered service in June 1949 in the Oklahoma Gas and Electric Company Belle Isle Station, and a similar system was added to this station in 1952. Figure 1 shows the gas turbines in these early combined-cycle systems. In June 1982, the ASME dedicated this first gas turbine as a historical landmark and it was relocated to Schenectady, New York, for display (Figure 2).

Most combined-cycle power generation systems installed in the 1950s and 1960s included conventional, fully-fired boilers (Table 1). These systems were basically adaptations of conventional steam plants with the gas turbine exhaust gas serving as



GT11402

Figure 1. Gas turbines - OG&E Belle Isle



RDC25115-12.4

Figure 2. First gas turbine - historical landmark

combustion air for the boiler. The efficiency of this type of combined cycle was approximately 5% to 6% higher than that of a similar conventional steam plant. These systems could economically utilize bare tubes in the boiler because of the high mean temperature difference between the combustion products and the water/steam.

Equipment to economically weld continuous spiral fins to tubes was introduced to the boiler manufacturers in 1958. Heat recovery combined cycles, which use the sensible heat in the gas turbine exhaust gas, were made feasible by enhanced gas side heat transfer by the use of resistance-welded, finned tubes. Finned tube boilers entered service in 1959.

During the 1960s, the heat recovery type of combined cycle became dominant. Its initial application was in power and heat applications where its power-to-heat ratio was favorable to many chemical and petrochemical processes. A small number of heat recovery-type combined cycles were installed in power generation applications in the 1960s. When gas turbines over 50 MW in capacity were introduced in the 1970s, the heat recovery combined cycle experienced rapid growth in electric utility applications.

The 1980s and early 1990s have brought a large number of natural gas-fueled systems, including plants designed for power only and those designed for power and heat (cogeneration) applications (Figure 3). The power-only plants utilize condensing steam turbines with minimum extraction for feedwater heating. The cogeneration systems utilize steam turbines that exhaust steam to a heat utilization process or extract it from a condensing steam turbine. Some cogeneration combined

	GT Model	MW	No. GTs
Combined Cycle (Power Only)	9000	24,044	124
	7000	19,463	138
	6000	1,940	48
	5000/3000	1,933	68
	Subtotal	47,380	378
Cogeneration (Power & Heat)	9000	1,410*	15
	7000	9,577*	116
	6000	5,275*	143
	5000/3000	3,755*	241
	Subtotal	20,017	515
Total		67,397	893

*No S.T. MW Included

GT17295P

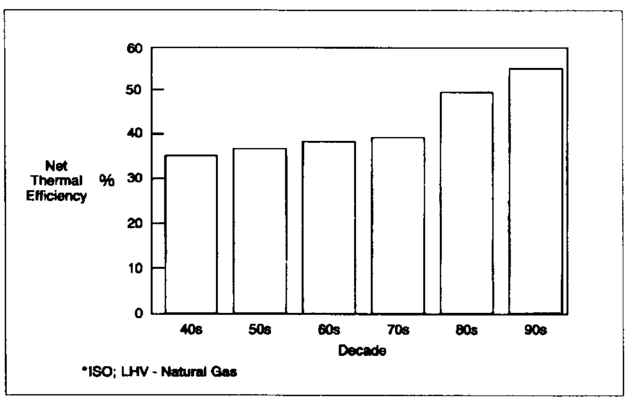
Figure 3. GE design gas turbines in combined cycle

cycles export the steam directly from the HRSG to the process.

One recent trendsetting power-only plant is at the Korea Electric Power Company Seoinchon site where eight advanced gas turbines are configured with dry low NO_X combustion systems and a reheat steam cycle. This 1886 MW plant is the most efficient operating to date at 55% (LHV) gross efficiency.

TRENDS

The thermal efficiency of combined-cycle plants has increased steadily (Figure 4). Combined-cycle efficiency improvements have been led by advances in gas turbine performance resulting primarily from higher firing temperatures. Combined cycles with high gas turbine firing temperature and unfired heat recovery steam generators (HRSGs) are the most efficient power generation systems currently available. Current plants are operating at net lower heating value (LHV) thermal efficiencies greater than 54%. This trend toward higher operating efficiencies will continue, improving the economics for clean fuels and gasification combined cycles using low cost fuels such as coal.



GT10009E

Figure 4. STAG combined-cycle efficiency

Unfired HRSG-type heat recovery combined cycles are also extensively used for power and heat applications. The efficiency of these systems can be increased by firing additional fuel in the HRSG. Firing the HRSG also provides flexibility in steam production. The PURPA legislation has increased interest in combination power and heat plants which has encouraged the use of combined cycles. The LHV thermal efficiencies of these plants can approach 90%.

During the last decade, environmental awareness (Figure 5) and legislated low stack emissions have made siting of power plants a critical issue. Japanese and USA rules have led the downward trend, with Europe and other high population density areas following. New combustion and emission control technologies have been introduced to meet the continually increasing stringency of environmental requirements without sacrificing reliability.

Table 1

COMBINED-CYCLE SYSTEMS WITH FULLY-FIRED BOILERS

COMMERCIAL OPERATION YEAR	OWNER	STATION	GAS TURBINE	COMBINED-CYCLE RATING (MW)
1949	Oklahoma Gas & Electric	Belle Isle	MS3001	40
1952	Oklahoma Gas & Electric	Belle Isle	MS3001	40
1954	West Texas Utilities	Rio Pecos	MS3001	35
1961	Western Power	Liberal, KS	MS5001	65
1973	Oklahoma Gas & Electric	Horseshoe Lake	MS8002	250
1974	Gulf Oil Co.	Port Arthur, TX	MS5001N	25
1974	Taunton, MA	Taunton	MS5001N	110
			TOTAL	565

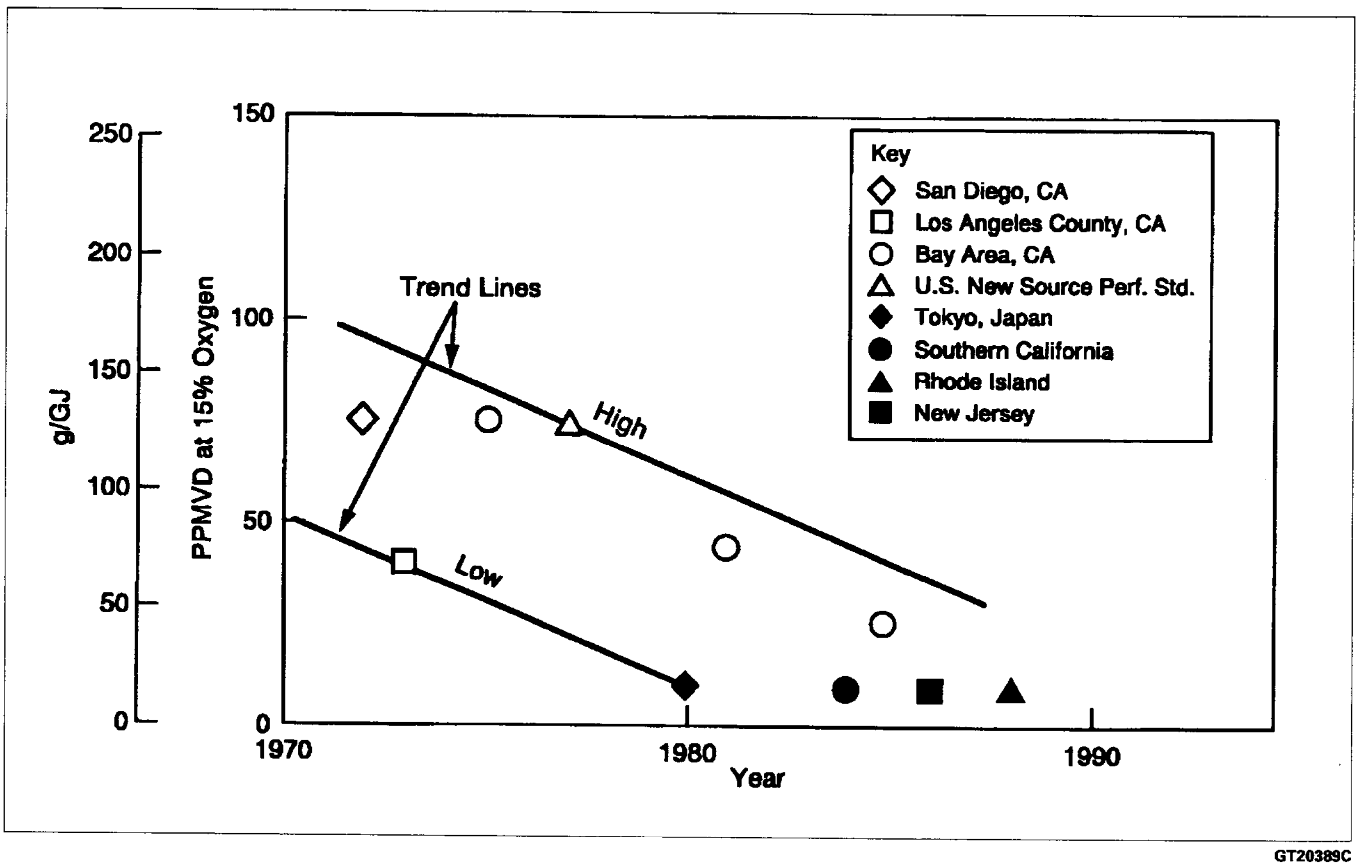
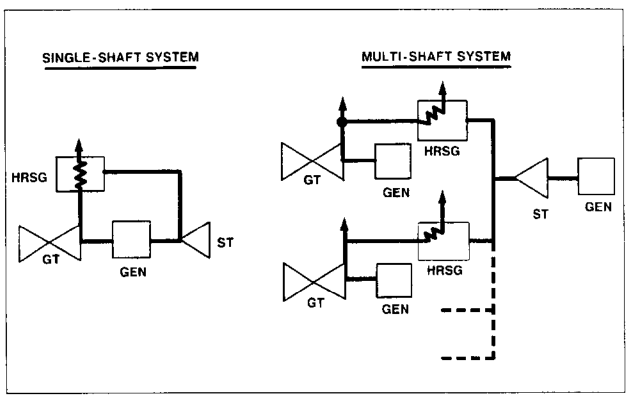


Figure 5. NO_X emission regulation trends

PRE-ENGINEERED STAG COMBINED-CYCLE SYSTEMS

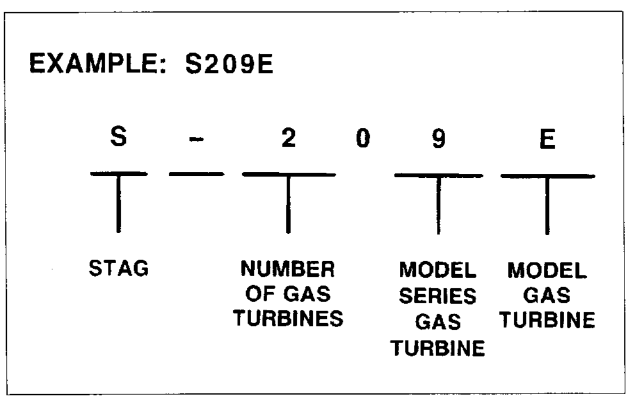
The GE pre-engineered STAG™ (STeam And Gas) combined-cycle power generation systems consist of factory-packaged components, including an integrated control system. It may contain from one to six gas turbines, including the MS5001, the MS6001, the MS7001, or MS9001. The STAG combined cycles include single- and multi-shaft (Figure 6) configurations. GE designates its systems by the letter and number sequence, as illustrated in Figure 7.

GE introduced pre-engineered heat recovery combined cycles for utility power generation in the late 1960s. The ratings of the early STAG systems ranged from 11 MW to 21 MW. Their operation has been excellent, and all are still in service. The Ottawa Water & Light 11-MW STAG 103 and Wolverine Electric Cooperative 21-MW STAG 105 systems (Figure 8) have both exceeded 100,000 hours of operation. The early experience and reliability of these systems, coupled with their efficiency benefits, led to the expansion of combined-cycle applications.



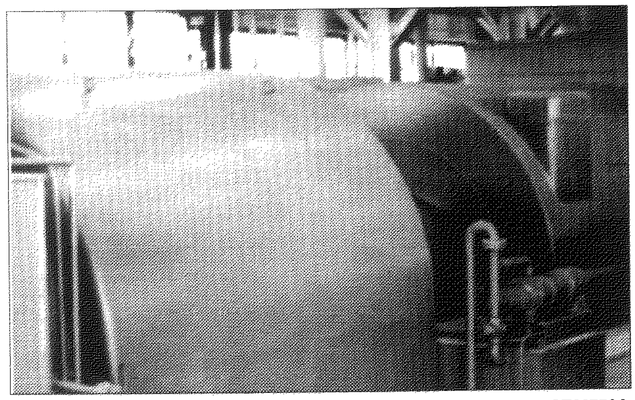
GT08107

Figure 6. STAG system arrangements



GT20675

Figure 7. STAG system designation



GT20770A

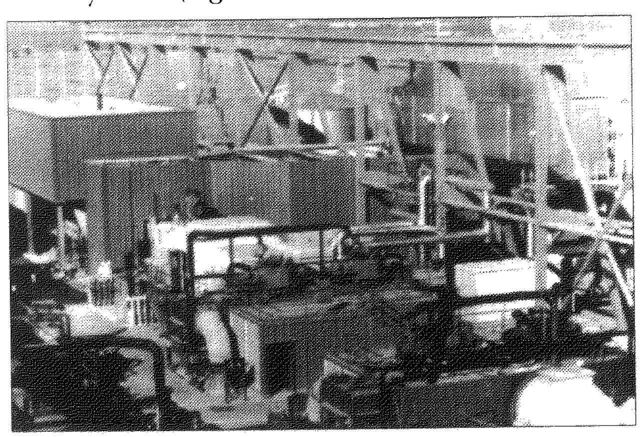
Figure 8. Wolverine Electric Co-op STAG 105

LARGE STAG POWER GENERATION SYSTEMS

The STAG power generation systems evolved with the introduction of larger, more efficient gas turbines. The first large multi-shaft STAG system (340 MW) was purchased by Jersey Central Power & Light in 1971. By the end of 1974, 15 more STAG systems were ordered by eight utilities. These were either single- or multi-shaft configurations and generation capacities ranged from 72 MW to 640 MW.

Table 2 lists all the GE power generation STAG combined-cycle systems currently in operation or on order.

Examples of large STAG systems with MS7001 gas turbines are the 288-MW Salt River Project Santan Station in Arizona (Figure 9), the 330-MW Duquesne Light Company STAG 307B system in Pennsylvania, and the 574-MW Houston Lighting & Power Wharton Station in Texas with two STAG 407B systems (Figure 10).



GT1475-1E

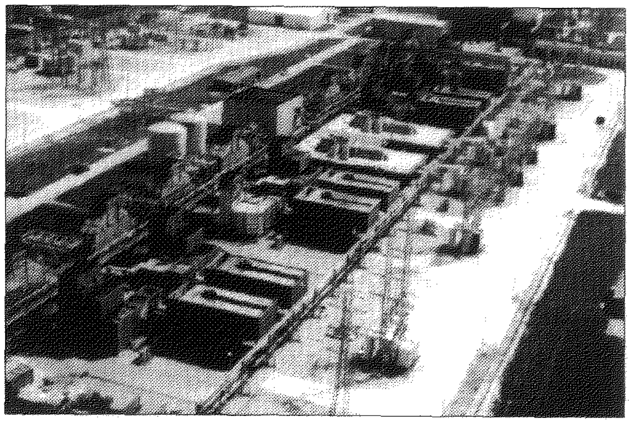
Figure 9. Salt River project

The Salt River Santan Station consists of four single-shaft STAG 107B systems. These units were originally designed to burn distillate oil fuel. All have been converted to burn natural gas fuel. The

Table 2
POWER GENERATION STAG COMBINED-CYCLE SYSTEMS

COUNTRY	UTILITY	NO. GTs	NO. STs	TOTAL MW	COMMERCIAL OPERATION	TOTAL GT HOURS (JAN. 1994)
USA	Wolverine Electric	1*	1	21	1968	141,400
USA	City of Ottawa	1*	1	11	1969	100,600
USA	City of Clarksdale	1*	1	21	1972	95,100
USA	City of Hutchinson	1*	1	11	1972	78,200
USA	Duquesne P&L	3	1	330	1974	47,700
USA	Houston Light	8	2	574	1974	230,200
USA	Salt River Project	4*	4	290	1974	208,500
USA	Ohio Edison	2	1	225	1974	59,200
USA	Jersey Central	4	1	340	1974	156,600
USA	Arizona Public Service	3*	3	250	1976	128,500
USA	Iowa Illinois G&E Co.	4	1	105	1977	58,000
USA	Puerto Rico EPA	8	2	606	1977	305,300
USA	Western Farmers	3*	3	278	1977	272,000
USA	Portland G&E	6	1	550	1977	73,300
Korea	Korea Electric	8	2	640	1979	87,300
USA	MMWEC	3	1	360	1983	105,200
Taiwan	Taiwan Power Company	6	2	570	1983	130,300
Mexico	CFE Mexico	4	1	375	1984	282,500
Argentina	EMSA	2	1	65	1984	115,400
USA	SCE Cool Water IGCC	1	1	120	1984	23,900
Trinidad	Trinidad & Tobago	2	1	198	1985	130,800
Japan	TEPCO-Group 1	7*	7	1,155	1986	281,600
Japan	TEPCO-Group 2	7*	7	1,155	1988	214,100
China	MPI Lama Dien II	1*	1	50	1986	35,600
Pakistan	WAPDA	4	2	623	1986	218,300
Japan	Chubu Electric Pwr. Co.	5*	5	577	1988	170,000
USA	Fayetteville	6	1	189	1988	72,700
Egypt	Egyptian Elec. Auth.	8	2	300	1988	718,600
USA	Ocean State Power	4	2	480	1990	82,300
USA	Virginia Power	2	2	420	1990/92	30,800
Thailand	EGAT	14	7	2,718	1990/92-94/96	98,900
Korea	KEPCO-Seoinchon	8	8	1,886	1992	46,300
USA	TECO Power Services	2	1	250	1992	5,200
Austria	ESG Linz	1	1	77	1993	4,100
Indonesia	PLN-Maura Karang	3	1	540	1993	14,100
Korea	KEPCO-Pyongtaek	4	1	531	1994	1,000
Japan	TEPCO-ACC	8*	8	2,800	1995	Design
UK	Derwent	4	1	220	1994	Design
Egypt	EEA-Cairo South	1	1	180	1994	Design
Mexico	CFE, Samalayuca II	3	3	700	1995	Design
Hong Kong	China Light & Power	8*	8	2400	1996	Design
USA	Tampa Electric	1	1	260	1996	Design
USA	Bechtel-Hermiston	2	2	425	1996	Design
Total		178	104	23,876		4,813,600

*Single Shaft



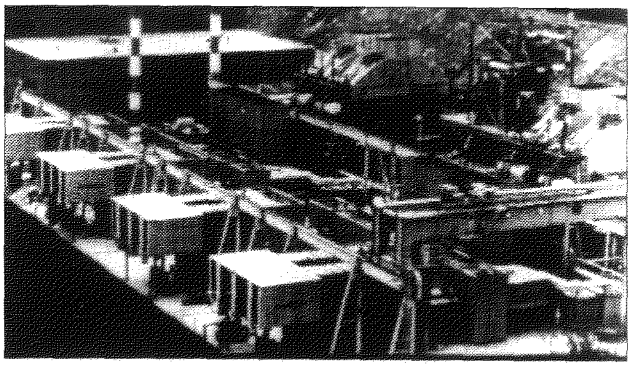
GT06432-1G

Figure 10. Houston Lighting and Power-Wharton Station

modern microprocessor control system used on current gas turbines was tested at this plant.

The Duquesne Light Company STAG 307B plant utilizes supplementary firing to increase the steam production. Supplementary firing for HRSGs is currently available, but seldom used for power generation plants because it reduces the efficiency. Supplementary firing is used advantageously in cogeneration applications or for matching new gas turbines to existing steam plants.

The Korea Electric Power Co. STAG 407B, 320-MW combined-cycle systems at Yongwol (Figure 11) and Kunsan were the first large STAG combined-cycle systems outside the USA. These started the trend of extensive international combined-cycle applications.

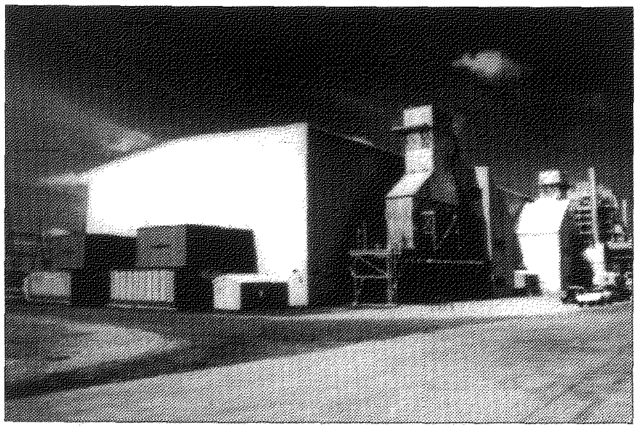


GT03682-F

Figure 11. Korea Electric Power Company - Yongwol

CURRENT TECHNOLOGY STAG SYSTEMS

The Western Farmers Electric Cooperative plant at Anadarko, Oklahoma (Figure 12), which entered commercial service in 1977, was the first to incorporate MS7001E gas turbines with modern firing temperatures of 2000 F/1100 C. Three single-shaft STAG units of 91.4 MW each are installed indoors. The 15-year operating statistics, which are typical of the current-technology STAG plants, show availability of 90% and maintenance costs below $0.001/kWh on natural gas fuel (Figure 13). Each of these STAG 107E combined-cycle systems has accumulated more than 90,000 fired hours.



GT08617-1F

Figure 12. Western Farmers Electric Cooperative plant

The current technology STAG systems are designed to operate reliably at mid-range or baseload (continuous duty). Examples of current technology STAG systems are the Massachusetts Municipal Wholesale Electric Company (MMWEC) 360-MW STAG 307E Stoney Brook Station (Figure 14), the Taiwan Power 600MW Tunghsiao Station with two STAG 307E systems (Figure 15), Tokyo Electric Power Company 2000-MW Futtsu Station, Chubu Electric Power Company 560-MW Yokkaichi Station, Trinidad and Tobago Electricity Commission 198-MW Penal Station (Figure 16), CFE (Mexico) 375-MW STAG 407E at Huinala Station (Figure 17) and WAPDA (Pakistan) 600-MW Guddu Station.

Five single-shaft STAG 107E units are installed in the Chubu Electric Power Company's Yokkaichi Station. Unique features of these units include the capability to burn liquefied petroleum gas (LPG) fuels in a vaporized phase, as well as liquefied natural gas; low NO_x emissions by a combination of selective catalytic reduction (SCR) in the HRSG and steam injection to the gas turbine; and a peak rating equal to the base load capability at low ambient air temperature which provides 5% to 7% increased output at ambient air temperature above 64 F (18 C) so that increased capacity of the steam cycle, its auxiliaries and cooling system are not required to accommodate the high ambient air temperature peak rating.

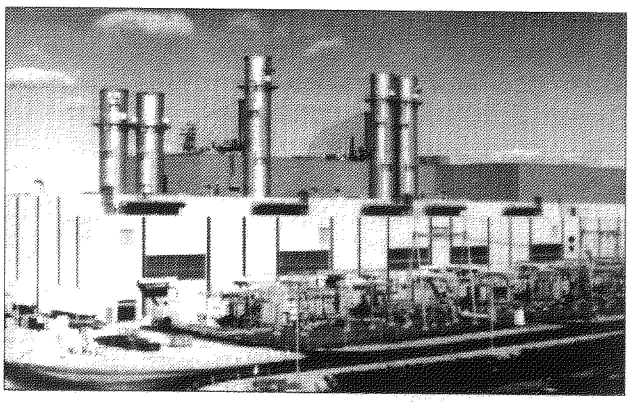
Special features to accommodate the LPG fuels (butane, propane or a mixture) include: a modified gas turbine enclosure ventilation system to draw air from the bottom of the enclosure, since LPG gas is heavier than air; a separate off-base fuel control module for LPG fuel and on-base system with separate LPG fuel manifold; and a special

	Plant Factor-%	Availability-%	Maintenance Mills/kWHr
1978	55	72	0.35
1979	61	83	0.31
1980	75	93	0.31
1981	73	90	0.53
1982	32	97	0.66
1983	31	99	0.75
1984	55	98	0.41
1985	39	79	1.54
1986	45	81	0.92
1987	61	97	0.59
1988	44	93	0.92
1989	48	96	0.73
1990	53	93	1.11*
1991	72	98	0.64
1992	76	89	1.38
1993	48	87	1.32
Average:	54	90	0.78

*Includes ~ 0.3 Mills/kWHr for Fuel Oil Retrofit

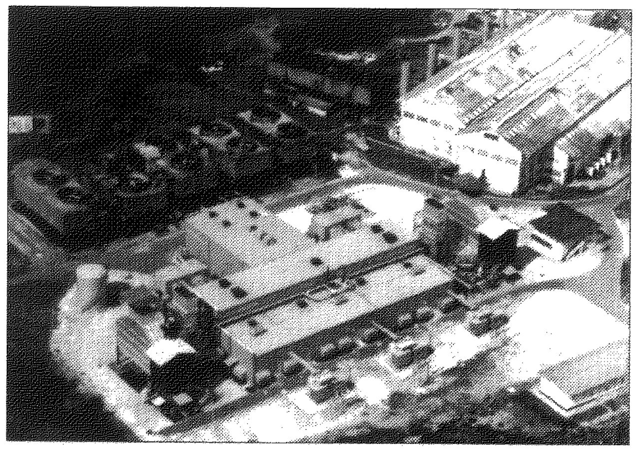
GT17346O

Figure 13. Western Farmers Electric Cooperative performance data



GT06801-3E

Figure 14. Massachusetts Municipal Wholesale Electric Company (MMWEC)

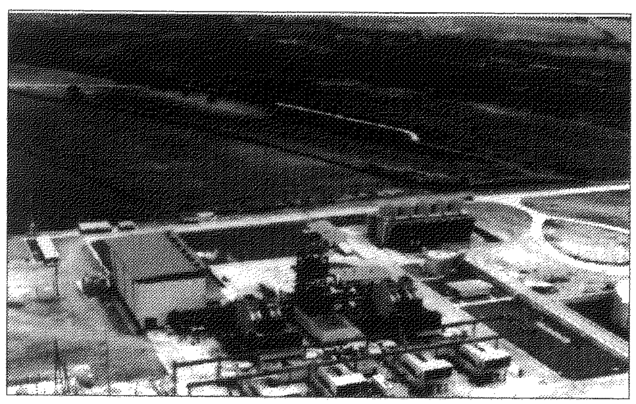


GT16030-D

Figure 16. Trinidad and Tobago Electric Company (T&TEC)

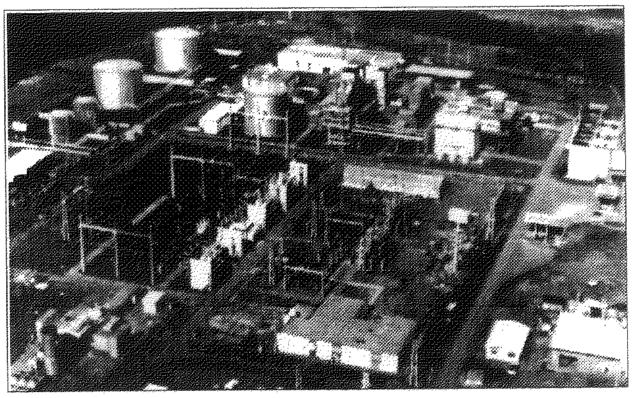
GT08010-2C

Figure 15. Taiwan Power



GT11601-4C

Figure 17. Comision Federal de Electricidad



GT12445-1

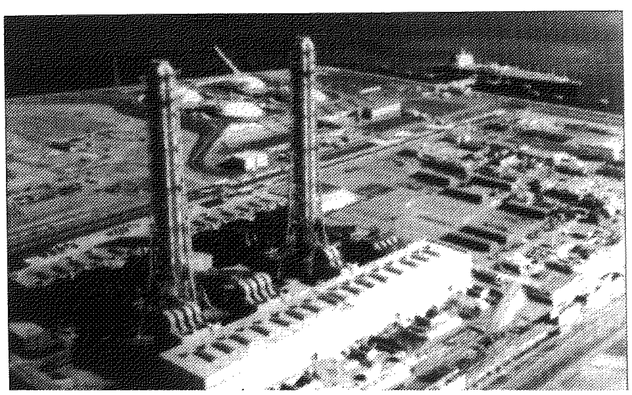
Figure 18. Electricidad de Misiones S.A.

HRSG and stack (656 feet/200 m in height) purge cycle that was verified by field test to assure satisfactory removal of LPG fuel from the exhaust system' prior to starting. These units entered service in 1987 and have accumulated 177,600 fired hours as of March 31, 1994, with 2,312 starts.

The Taiwan Power STAG 307E power generation systems utilize residual oil fuel treated on site prior to burning in the gas turbine. A 65-MW STAG 205 plant was installed at Electricidad de Misiones (EMSA) in Argentina in 1984 (Figure 18). The gas turbines burn residual oil that is treated on site. One HRSG receives exhaust gas from two gas turbines through a damper system that enables operation of one or both gas turbines. This is an excellent example of a reliable, residual oil-fired, small power generation combined-cycle system.

TEPCO FUTTSU STATION

TEPCO Futtsu Station (Figure 19) is a noteworthy power generation installation with 14 single-shaft STAG 109E combined-cycle units, each with 165 MW capacity at ISO conditions. This is the world's largest combined-cycle power plant with unfired steam cycles with a 2000-MW rating at site conditions. The equipment is installed in two 1000-MW groups which are each connected to the system through a single transformer. Fuel is liquefied natural gas (LNG) which is burned in the vapor phase.



GT16590-1E

Figure 19. Tokyo Electric Power Company (TEPCO) - Futtsu Station

Distinguishing characteristics of this power generation facility are:

- High thermal efficiency – 48.5% based on LHV of natural gas fuel
- Lowest environmental impact – NO_X less than 10 ppmvd at 15% oxygen (17 g/gJ)
- Flexible operating characteristics for daily start-stop operation, load following or continuous base load
- Minimum site space requirement
- Reliable operation
- Low maintenance

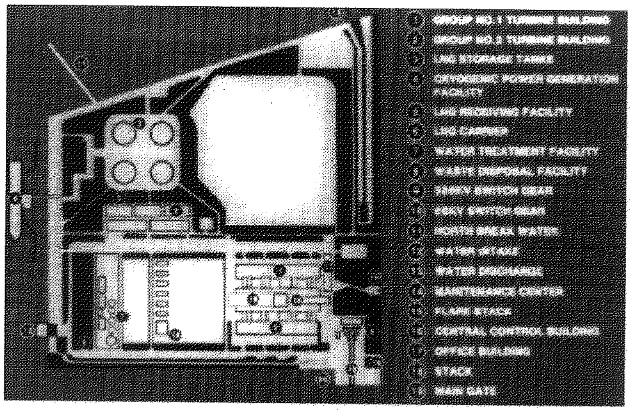
TEPCO selected the single-shaft STAG configuration for Futtsu rather than multi-shaft because of:

- Minimum land requirements since bypass stacks are not required and the number of generators and electrical trains are reduced
- Simplified unit controls for high reliability
- Convenient daily start-stop operation
- Independent units enabling a modular maintenance program for best availability

Environmental considerations were a primary influence on the selection of the combined-cycle power generation equipment and station design. NO_X emissions are controlled to less than 10 ppmvd at 15% oxygen (17 g/gJ) by steam injection into the combustor reaction zone and selective catalytic reduction (SCR) in the HRSG. Stacks are 656 feet (200 m) in height.

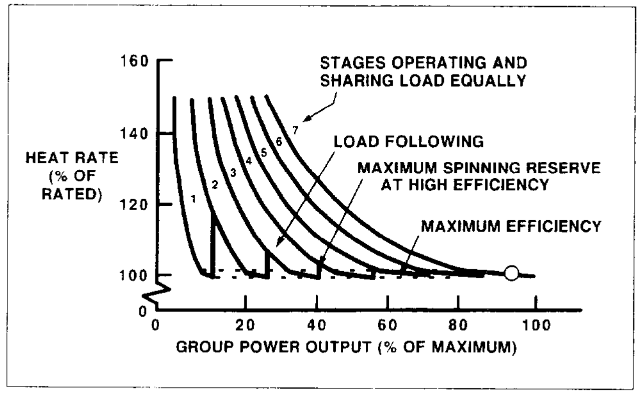
The acoustic requirements are stringent both in the near field and at the plant boundary. Residences located at the boundary dictated 60 dBA sound pressure level (SPL). The turbine building is sheathed with sound attenuating concrete panels for acoustic attenuation, attractive appearance and low maintenance in a corrosive, coastal atmosphere. The major equipment is housed in sound attenuating enclosures on foundations separate from the equipment to satisfy the average SPL of 85 dBA at a distance of 3.28 feet (1.0 m) from the enclosures.

Low thermal discharge to cooling water is an inherent characteristic of combined-cycle generation equipment because one-third of the output is from the steam cycle and two-thirds is from the gas turbines. The heat rejection to the cooling water is about 60% of that from conventional steam plants. At Futtsu, the cooling water temperature rise does not exceed 12.6 F (7 C). The two power generation groups and the LNG system share common sea water intakes and discharge flumes. Each unit has an individual condenser



GT18555

Figure 20. TEPCO Futtsu Station arrangement



GT18535

Figure 21. 1000-MW group heat rate variation with output

cooling water pump. The equipment cooling is performed by a common auxiliary cooling water system for each group.

The plant site (Figure 20) is on the Futtsu Peninsula on the eastern side of Tokyo Bay. The site is a man-made extension of land formed by dredging sand from Tokyo Bay. The combined-cycle power generation equipment occupies a land area approximately 985 feet x 985 feet (300 m x 300 m), which is a small part of the total reclaimed land area for the generation plant and support facilities.

The LNG receiving, storage and handling facilities occupy approximately half of the area. This system accommodates ocean-going ships and has a storage capacity of 66,000,000 gallons (250,000 M^3) of LNG.

The 1000-MW combined-cycle group has outstanding load-following characteristics and achieves excellent part load performance by sequentially loading individual units as shown in Figure 21. Rated heat rate is achieved from 14% to 100% load by sequentially loading stages at maximum output. When operated in a load following mode, the sequential loading also results in outstanding part load heat rate. The heat rate of each unit is essentially constant from 80% to 100% load where the gas turbine compressor inlet guide vanes are modulated to maintain rated gas turbine firing temperature. This enables the group or individual units to operate with approximately 20% spinning reserve with high thermal efficiency.

Daily start-stop operation requires fast starting and loading of the equipment. The STAG 109E unit starts and loads within one hour after ignition following a 12-hour shutdown period. When

Table 3

TEPCO FUTTSU STATION OPERATION SUMMARY – March 31, 1994

STAGE	FIRED HOURS	STARTS	FIRED HOURS / START
I-1	44,590	969	46.0
I-2	43,049	1127	38.2
I-3	40,578	978	41.5
I-4	40,316	1172	34.4
I-5	40,039	1107	36.2
I-6	39,474	1103	35.8
I-7	40,641	1025	39.6
II-1	33,157	858	38.6
II-2	34,489	874	39.5
II-3	31,949	856	37.3
II-4	31,761	825	38.5
II-5	30,311	734	41.3
II-6	31,878	672	47.4
II-7	30,341	709	42.8
Total	512,573	13,009	39.4

Table 4

TEPCO FUTTSU STATION RETEST DATA

Unit	Fired Hours At Retest	Output Change From Acceptance Test (%)	Efficiency Change From Acceptance Test (%)
1-1	32,000	-4.0	-1.0
1-3	28,000	-2.8	+0.4
1-7	26,000	-1.6	-0.3
2-1	20,000	-0.6 → +0.5	-1.0 → +0.1
2-3	20,000	-0.2	-0.4
2-5	18,000	-0.7	-1.8

Measurement Uncertainties: Output ± 1.31% Efficiency ± 2.21%

All Retested Units Exceeded New and Clean Guarantees

GT22815

the equipment is cold, approximately three hours are required for starting and loading. The starting and loading program is varied depending on the steam turbine shell temperature prior to starting. After a weekend shutdown, the unit starting and loading time is approximately two hours.

The STAG 109E combined-cycle units at Futtsu have operated reliably to satisfy the TEPCO system needs for economical mid-range, load following generation requiring daily start and stop operation. Table 3 presents the operating hours and starts for each unit. As of March 31, 1994, the 14 units had 512,573 total operating hours with 13,009 total number of starts. The average fired hours per start is 39.4. As directed by the Japanese Electric Utility Law, each STAG 109E unit receives a major inspection once every two calendar years. The average reliability has exceeded 99.9%.

SUSTAINED PERFORMANCE

Six of the 14 STAG 109E units were retested in 1992 to evaluate sustained performance. The procedure was comprehensive and included a tightly controlled calibration of instrumentation and measurements of critical values at the primary elements. Even so, the calculated measurement uncertainty was + 1.31% on output, and + 2.21% on efficiency. Tests utilizing uncalibrated station instrumentation processed through a central computer will have higher measurement uncertainties.

Before the retests, the units were washed, including compressor, turbine and HRSG. In some cases, this returned 4.6% of output and 2.6% of efficiency recoverable losses. However, even after cleaning, corrected HRSG gas side pressure drop indicated higher values.

A summary of the test results is presented in Table 4. Test results were corrected back to rating point conditions: 89.6 F (32 C) and 14.7 PSIA (1.033 kg/cm^{2}A). The correction is necessary to provide data that can be compared on a consistent basis, but adds off-design calculation accuracy as another variable. It is important to understand how some of these causes can affect the results. Within the measurement uncertainties, all units met their original efficiency acceptance test values. Without measurement uncertainties included, all units exceeded output and efficiency guarantees, even after 32,000 actual fired hours. A properly operated and well maintained combined cycle is expected to sustain high performance levels during the plant life.

Combined-Cycle Repowering

Repowering is the combination of new gas turbines with existing steam turbines or steam cycles to form combined-cycle systems. The most commonly applied system is the heat recovery type of repowering system that includes gas turbines and HRSGs, which generate steam for existing steam turbines. The GE experience includes 1187 MW of heat recovery repowering cycle capacity (Table 5). The existing fired boiler is retired when the steam turbines are repowered. This type of repowering produces a combined cycle with high thermal efficiency and increases generating capacity by a factor of two or three without a significant

Table 5

HEAT RECOVERY COMBINED-CYCLE REPOWERING SYSTEMS

OWNER	STATION	GAS TURBINE	GAS TURBINE RATING (MW)	COMBINED-CYCLE RATING (MW)	COMMERCIAL OPERATION YEAR
Community Public Service	Lordsburg, NM	1-MS5001K	12	20	1961
Wheatland Electric Co-op	Garden City, KS	1-MS5001L	14	21	1967
Carolina Power & Light	Cape Fear, NC	4-MS5001LA	64	90	1969
South Carolina Elec. & Gas	Parr, SC	4-MS5001M	68	128	1971
China Light & Power	Hok Un, Hong Kong	1-MS5001M	17	25	1972
Citizen Utilities	Kavia, Hawaii	2-MS5001N	46	70	1978
Anchorage, AK	Anchorage, AK	1-MS7001E	71	105	1979
Gaylord Container	Antioch, CA	1-MS6001A	36	42	1983
City of Vero Beach	Vero Beach, FL.	1-MS6001B	38	57	1992
LA DWP	Harbor, CA	2-MS7001EA	167	249	1993
Imperial Irrigation Dist.	Los Angeles, CA	1-MS7001EA	84	120	1994
Public Service of Indiana	Wabash, IN	1-MS7001FA	192	260	1996
	Totals	20	809	1187	

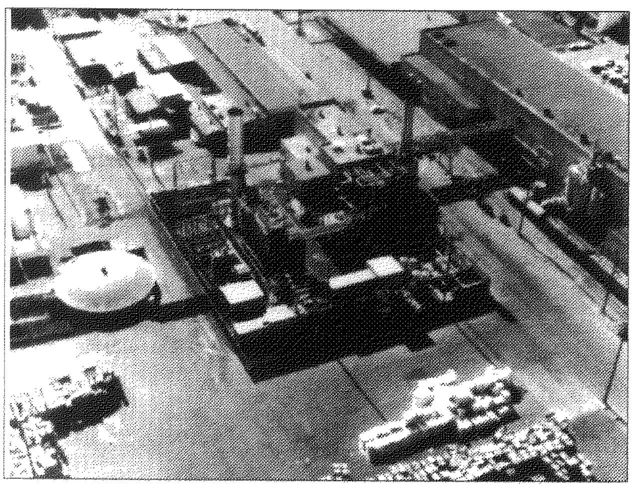
change in the cooling water requirement. Heat recovery repowering has been applied only to nonreheat steam turbines, but the advanced gas turbines, MS6001FA, MS7001FA and MS9001FA, have a high exhaust gas temperature so that they can be applied to repower existing reheat steam turbines and have excellent economic benefits.

Conventional steam power generation and cogeneration plants have been repowered by gas turbines to form combined cycles with fully-fired boilers. In these plants, the gas turbine exhaust gas is used as combustion air for the boiler or the turbine exhaust energy heats feedwater. The repowering systems operating with fully-fired boilers are included in the experience list in Table 1. The West Texas Utilities Rio Pecos plant is a repowering power generation combined-cycle system with the gas turbine supplying combustion air to the boiler. The Texas Refinery Cogeneration System, Gulf Oil Company Port Arthur, is a similar system. Examples of feedwater heater repowering are the Oklahoma Gas & Electric Belle Isle Unit and the Western Power Units at Liberal, Kansas.

COGENERATION COMBINED CYCLES

Dual-use power and heat cogeneration plants provide the highest energy conversion efficiency available today. To achieve this high energy conversion, these plants serve two energy users, typically a host process heat user and an electric utility. This dual customer arrangement requires high availability and reliability to achieve the required financial objectives.

Table 6 presents the operating experience of modern combined-cycle cogeneration systems with MS6001 gas turbines and Table 7 presents experience of similar systems employing MS7001 gas turbines. Heavy-duty gas turbine examples are the Gaylord Container MS6001 unit at Antioch, California (Figure 22), which generates steam for an existing automatic extraction con-



GT08820-1C

Figure 22. Gaylord Container

Table 6
GE GAS TURBINE COGENERATION OPERATING EXPERIENCE — MS6001

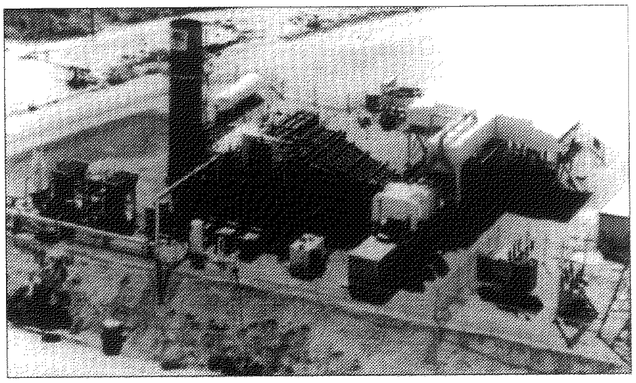
CUSTOMER	LOCATION	NO. GTs	GT MW	COMMERCIAL OPERATION	TOTAL GT HOURS (JAN. 1994)
Gaylord Container	Antioch, CA	1*	36	1983	92,300
Texaco	Port Arthur, TX	1	36	1984	72,600
AMOCO Chemicals	Texas City/Chocolate Bayou, TX	2	72	1984	127,200
Inland Container	Ontario, CA	1	36	1985	54,800
GE Plastics	Netherlands	2	74	1985/89	101,200
Statoil	Norway1	1	37	1985	9,600
BASF	Geismar, LA	1	36	1986	69,700
Formosa Plastics	Baton Rouge, LA	2*	72	1986	91,800
	Point Comfort, TX	1	36	1989	58,100
Indian Petrochemicals	India	2*	58	1986	79,000
Borden Chemical	Geismar, LA	2	74	1986	122,900
MPI China	Daqing, PRC	1	35	1987	46,300
University Energy	Taft, CA	1	38	1987	58,300
Cardinal Cogen	Palo Alto, CA	1*	38	1987	46,400
Chevron	El Segundo, CA	2	72	1987	97,700
Union Carbide	Seadrift, TX	2*	76	1987	102,100
Karamay	PRC	1	35	1988	17,300
Cogen Technologies	Bayonne, NJ	3*	114	1988	128,600
Fina Oil & Chemical	Beaumont, TX	1	36	1988	43,700
Koch	Corpus Christi, TX	1	36	1988	46,000
IVO	Helsinki, Finland	1	36	1988	10,900
ANR	Hartford, CT	1*	38	1988	41,300
Southeast Paper	Dublin, GA	1*	36	1989	36,400
Exxon	Baytown, TX	3	108	1989	111,300
Encogen	Sweetwater, TX	1	36	1989	35,600
Energy Factors, Inc.	San Diego, CA	1*	38	1989	26,400
Kaltim	Indonesia	1	36	1989	43,900
Celanese	Bishop, TX	1	36	1989	38,700
Midset	Fellows, CA	1	36	1989	39,000
Cain Chemical	Corpus Christi, TX	1	36	1989	38,500
Dexter Paper	Windsor Locks, CT	1*	56	1989	32,000
Ebasco/Lonestar	Sweetwater, TX	1	38	1989	14,000
Champion Paper	Courtland, AL	1	38	1989	30,900
		1	38	1991	650
Fluor Altresco	Pittsfield, MA	3*	115	1990	81,400
Zurn/NEPCO	Tonawanda, NY	1*	38	1990	33,400
	Oswego, NY	1*	38	1990	29,300
	Ilion	1	38	1992	4,500
	Kirkwood	1	38	1993	**
Mission Energy/Magna	Henderson, NV	2	77	1990	1,000
Saquaro	Henderson, NV	2*	77	1991	36,400
Ebasco/EMI-PPA	Pawtucket, RI	1*	38	1990	1,000
Empire Energy	Lockport, NY	3*	115	1990	33,500
Panda Energy	Roanoke, Rapids, NC	1*	38	1990	2,100
Ansaldo/Kamine/	Glens Falls, NY	1*	38	1990	18,500
Besicorp	Carthage, NY	1*/1	76	1991/93	17,800
Ebasco/Trigen	Nassua	1*	38	1991	20,600
Warri Refinery	Nigeria	2	76	1991	31,800
Indeck	Silver Springs, NY	1	38	1991	22,000
Salinas Cogen	Salinas River, CA	1	38	1991	3,900
Sterling/Zurn NEPCO	Oneida, NY	1	38	1991	20,800
March Point/Texaco	Anacordes, WA	3	115	1991	15,900
Texaco	Sargeant Canyon	1	38	1991	4,000
EMI/Dartmouth		1*	38	1991	8,600
Texaco	Port Neches, TX	2	76	1992	30,100
C.U. Energy	Lockport, NY	3	115	1992	**
Sithe	Batavia, NY	1	38	1992	12,200
American Brass	Buffalo, NY	1	38	1992	14,800
CNF/Ft. Orange	Ft. Orange, NY	1	38	1992	13,200
Union Carbide/Linde	Texas City, TX	1	38	1992	**
Enserch/Encogen NW		3*	114	1992	2,700
March Point Cogen	Anacortes, WA	1	38	1992	**
Dartmouth Power Assoc.	Dartmouth, MA	1	38	1992	8,600
Mobil Cogen	Beaumont, TX	1*	38	1993	**
Harris/CTJ Power		1	38	1993	900
Big Three		1	38	1993	**
Encogen Northwest	Bellingham, WA	3	115	1993	**
Exxon Oil	Santa Ynez, CA	1	38	1993	600
Colorado Power	Brush, CO	1*	38	1993	**
North Tonawanda	Tonawanda, NY	1*	38	1993	1,900
International Paper	Riverdale, USA	1	38	1995	**
PT Cikarang	Indonesia	2	76	1995	**
Totals		101	3,790		2,436,650

Total MW Does Not Include Steam Turbine Power — *With Steam Turbine — **Under Construction

Table 7
GE GAS TURBINE COGENERATION OPERATING EXPERIENCE — MS7001

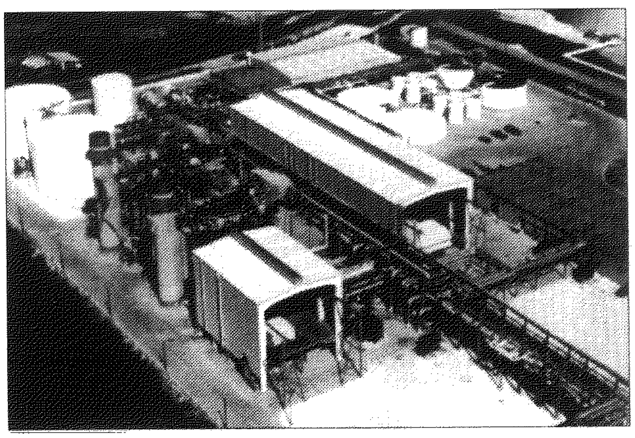
CUSTOMER	LOCATION	NO. GTs	GT MW	COMMERCIAL OPERATION	TOTAL GT HOURS (JAN. 1994)
Dow Chemical	Canada	2*/2	252	1972/79	484,200
ALCOA	Surinam, S.A.	1	49	1976	67,800
PPG Industries	Lake Charles, LA	2/2	270	1978/86	371,800
Dow Chemical	Freeport, TX	4*	281	1982	398,400
Occidental Oil	LaPorte, TX	2*/1	225	1982/86	241,600
Bayou Cogen	Bayport, TX	4	300	1985	298,900
Kern River Cogeneration	Bakersfield, CA	4	300	1985	284,500
Texas Gulf Cogeneration	New Gulf, TX	1	80	1985	67,900
Cogen Lyondell, Inc.	Pasadena, TX	5*	390	1986	320,000
AMOCO Oil	Texas City, TX	2*	156	1986	101,900
DuPont	Victoria/Orange, TX	2	160	1987	108,600
Gilroy Foods	Gilroy, CA	1	80	1987	38,100
HSPE/Falcon Seaboard	Big Springs, TX	2*	160	1988	96,800
Sycamore Cogeneration	Bakersfield, CA	4	300	1988	203,800
Watson Cogeneration	Carson, CA	4*	390	1988	191,800
Harbor Cogen	Long Beach, CA	1	76	1988	38,100
Midway Sunset	Bakersfield, CA	3	240	1989	121,200
Basic American Foods	King City, LA	1*	80	1989	23,400
Smith/Firestone	Oklahoma City, OK	1*	84	1989	34,700
Encogen	Sweetwater, TX	2*	168	1989	48,300
Ebasco/Lonestar	Sweetwater, TX	2	168	1989	60,900
HSPE/Tenaska	Paris, TX	2*	168	1989	49,500
Exxon Chemical	Baton Rouge, LA	1	82	1990	30,700
Eagle Point Cogen	W. Deptford, NJ	2	168	1991	43,900
Formosa Plastics	Point Comfort, TX	5	340	1991	1,000
Cogen Technologies	Linden, NJ	5	418	1991	57,000
Ebasco/ANR	Eagle Point, NJ	2*	167	1991	10,000
Panda Energy	Roanoke Rapids, NJ	1*	84	1990	1,800
Cogen Partners	Pedricktown, NJ	1	84	1991	6,800
Selkirk/Bechtel	Selkirk, NY	1/1*	167	1992/94	10,800
Cogen Technologies	Camden	1*	84	1993	1,600
Tenaska	NW Project/Ferndale	2/1*	250	1993/94	**
Destec	Oyster Creek	3*	251	1993	**
Destec	Tiger Bay	1	159	1995	**
Destec	Lyondell	1	84	1995	**
Falcon Seaboard	Saranac Energy	2	167	1993	**
Nesco	Sumas Energy	1*	84	1993	1,300
WWP PGE	Beaver	2	167	1993	**
Saranac Energy	Plattsburg, NY	2*	167	1993	**
Sumas Cogeneration		1*	84	1993	**
Sithe	Scriba, NY	4*	636	1994	**
Gordonsville Energy	Louisa, VA	2*	167	1994	**
Mulberry Cogeneration	Bartow	1*	84	1994	**
Corp. D.E.E.	Dominican Rep	1*	84	1995	**
Ebasco/Portland	Coyote Springs	1	159	1995	**
ENI/Bechtel	Crockett	1	159	1995	**
Indeck	Corinth, NY	1	84	1995	**
Kissimmee	Cane Island, FL	1	84	1995	**
Shell Oil	Deer Park, TX	2	168	1995	**
Total		107	9,009		3,757,800

Total MW Does Not Include Steam Turbine Power — *With Steam Turbine — **Under Construction densing steam turbine generator in a paper mill; the University Energy MS6001 plant in California (Figure 23); the AMOCO Chemicals plant in Texas City, Texas, with two MS7001EA gas turbines (Figure 24); the Watson Cogeneration 390-MW plant with four MS7001EA gas turbines (Figure 25); the Bayou Cogen 300-MW plant at Bayport, Texas; and the Power Systems Engineering Cogen Lyondell 490-MW plant.



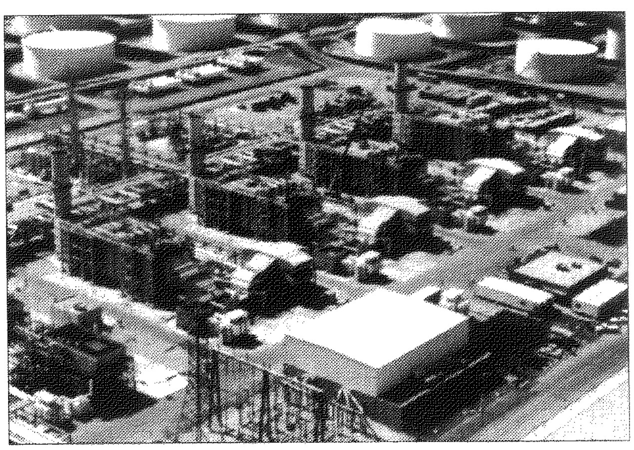
GT17351-1C

Figure 23. University Energy



GT17601-2C

Figure 24. AMOCO Oil

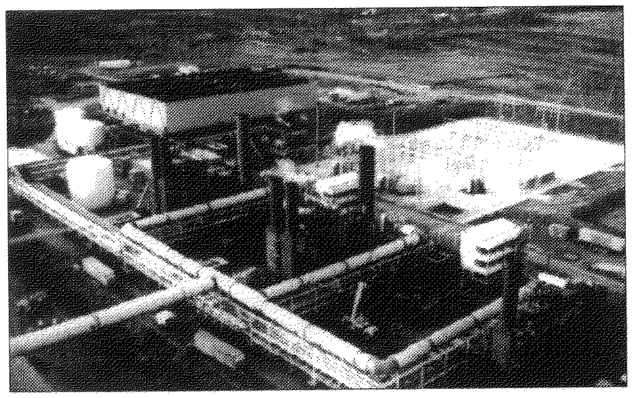


GT18100-2C

Figure 25. Watson Cogeneration

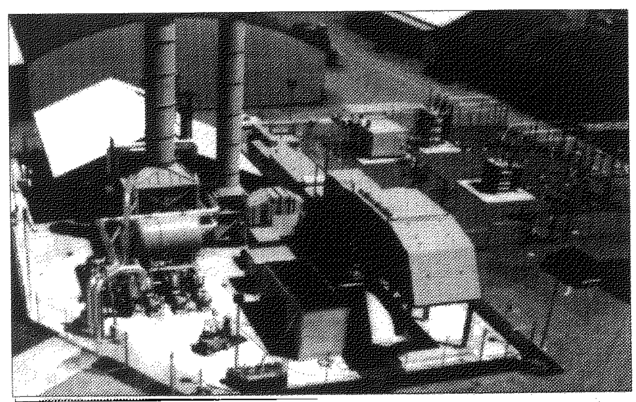
One recent plant, the Sweetwater Project at Sweetwater, Texas, utilizes one MS6001 and two MS7001 gas turbines, which generate steam for a single steam turbine with extraction for process steam that is sold to an adjacent industrial host. This plant utilizes an air-cooled exhaust steam condenser (Figure 26).

Operating experience on GE aircraft-derivative gas turbines in cogeneration combined cycles has been excellent. Almost 4,000 MW of GE design aircraft-derivative gas turbines have been applied in combined-cycle service (Table 8). The 20-MW LM2500 unit in the Pacific Cogeneration Plant (Figure 27) is a typical installation.



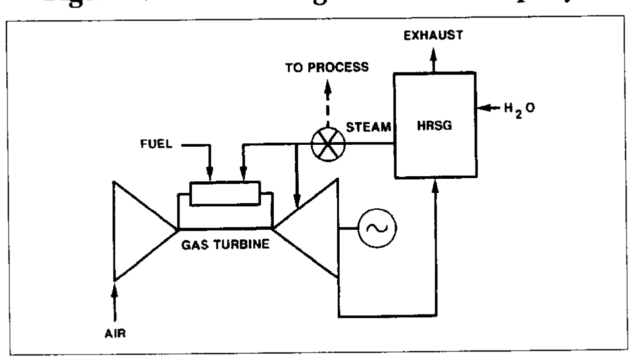
GT19787-1

Figure 26. Sweetwater Project



GT08724-1

Figure 27. Pacific Cogeneration Company



GT17342

Figure 28. Typical LM5000 STIG cycle

STIG™ (Steam Injected Gas) cycles, in which steam is generated by the exhaust heat and injected into the gas turbine, are used primarily with the high pressure ratio aircraft-derivative gas turbines (Figure 28). These cycles have been predominantly applied in cogeneration applications with intermittent process steam demand.

Table 8
GE DESIGN AIRCRAFT DERIVATIVES IN COMBINED CYCLE

GT Model	MW	No. GT
LM1600	140	10
LM2500	849	37
LM5000	1,096	26
LM6000	1,782	44
Total	3,867	117

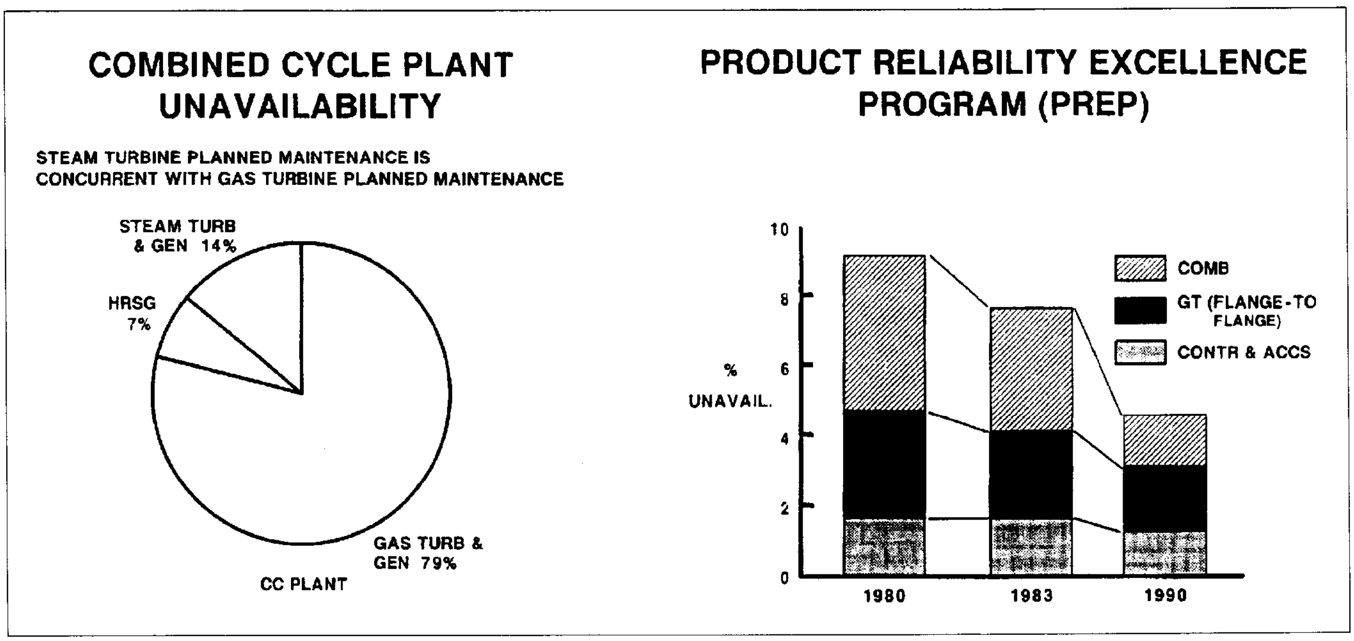
GT22816A

RELIABILITY AND AVAILABILITY

To ensure the continued upward trend for reliability and availability, a study was made of all combined-cycle outages reported through the GE/User weekly log system for the Operational Reliability Analysis Program (ORAP) in the early 1980s. Outages and their causes were categorized and reported by the operators, enabling definitive analysis. While information reported by the North American Reliability Council (NERC) indicated high reliability of GE gas turbines, the ORAP Combined-Cycle Outages study showed that 79% of combined-cycle outages were caused by gas turbine associated problems (Figure 29). The categorized causes enabled concentration on specific improvements, for example, controls, combustion systems and accessories. The program goal was to reduce combined-cycle unavailability to 5%, including maintenance and unplanned outages. The improvements developed through this program are incorporated in the current GE gas turbine product line and many have been retrofitted to the operating fleet.

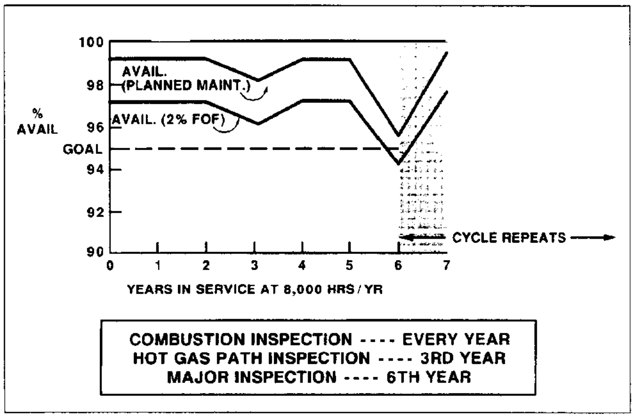
Recommended operating intervals between planned maintenance on heavy-duty gas turbines using natural gas or distillate oil fuels are a combustion inspection after 8,000 actual fired hours, a hot gas path inspection after 24,000 actual fired hours, and a major overhaul after 48,000 actual fired hours. Plotting the time required for these planned outages and including a forced outage rate up to 2% indicates an average availability greater than 95% (Figure 30). The ORAP statistics (Figure 31) show MS7001 gas turbine reliabilities of 98% (2% forced outage rate) which confirms the capability of combined-cycle plants to achieve greater than 95% availability.

The reliability and availability of cogeneration plants incorporating current-technology gas turbines have consistently been high and maintenance costs have been low so that the stringent



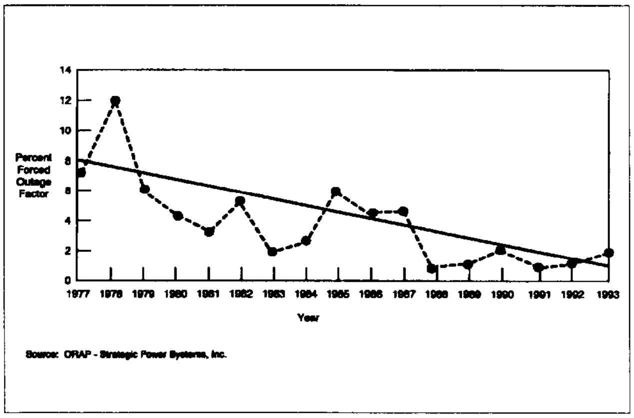
GT18145C

Figure 29. ORAP combined-cycle outage study



GT17298D

Figure 30. Gas turbine availability



GT20447D

Figure 31. Forced outage factor performance, all MS7001 USA domestic units

Service Factor	95.0%
Reliability	99.1%
Availability	95.2%
Total Fired Starts (4 Units)	1,110
Total Fired Hours (4 Units)	283,200

GT18189D

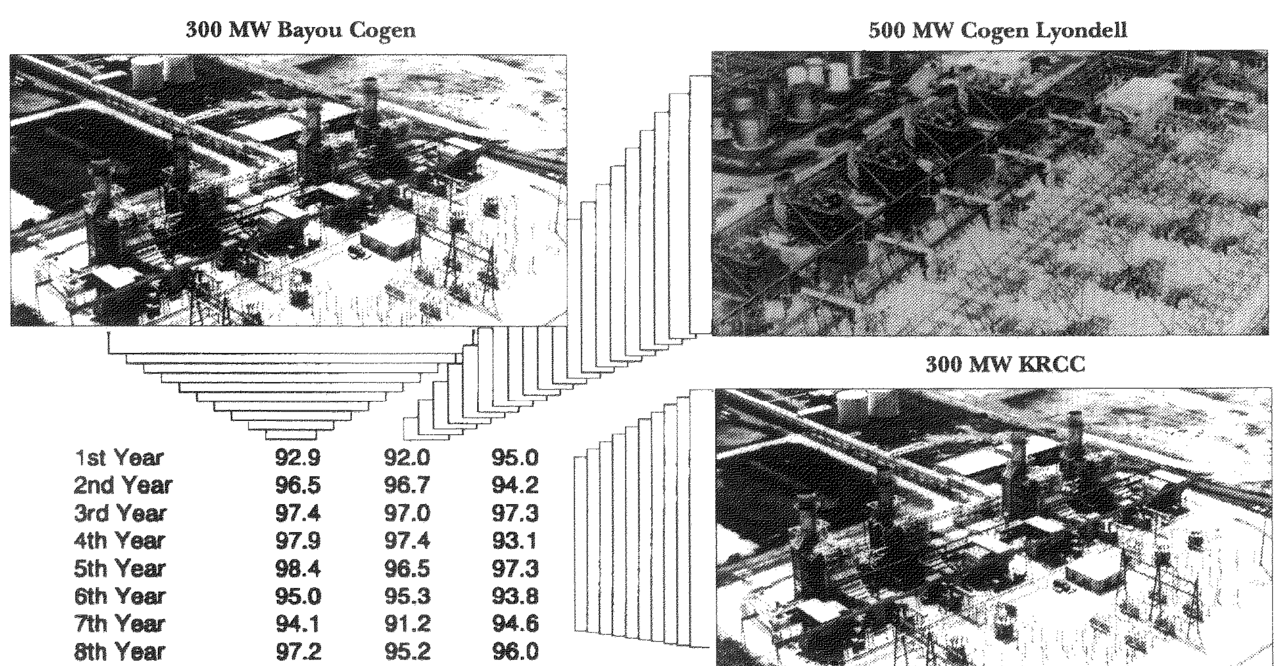
Figure 33. KRCC Omar Hill Plant operating statistics

	COMB INSP.	HOT GAS PATH INSP.	MAJOR INSP.
OUTAGE DURATION* (DAYS)	3	7	21
AVERAGE OUTAGE COST (LABOR & MATERIALS)	$150,000	$295,000	$1,500,000

*24 HOUR PER DAY MAINTENANCE ACTIVITY

GT18251C

Figure 34. KRCC gas turbine maintenance experience



1st Year	92.9	92.0	95.0
2nd Year	96.5	96.7	94.2
3rd Year	97.4	97.0	97.3
4th Year	97.9	97.4	93.1
5th Year	98.4	96.5	97.3
6th Year	95.0	95.3	93.8
7th Year	94.1	91.2	94.6
8th Year	97.2	95.2	96.0
9th Year	95.8	97.1	95.3

GT17665L

Figure 32. Gas turbines at baseload - availability percentage

financial objectives of these plants have been satisfied. This is illustrated by the availability statistics (Figure 32) for three baseload plants that have completed nine years of operation. Mission Energy Company, a subsidiary of Southern California Edison and Texaco, built the 300-MW KRCC Omar Hill plant which achieves excellent reliability and availability as shown by their published operating statistics (Figure 33) and maintenance costs (Figure 34) for the MS7001 gas turbines in this plant.

MS6001 gas turbine operators have formed a users group which reports on operations and develops programs for improvements. They report that the MS6001 cogeneration fleet is averaging over 96% availability. The 27 domestic units reporting through the strategic power system also report a gas turbine generator availability from 95.6% to 97.5%.

OPERATION AND MAINTENANCE SERVICES

Operation and Maintenance (O&M) services are available directly from GE. GE Operation and Maintenance Services began operating the Bayou Cogeneration plant located in Pasadena, Texas, during 1985. GE O&M services has grown to nine operating plants totaling 1,670 MW. Since 1985, 92 unit years of O&M services have been provided with an average availability of 95.6% (Figure 35). Plant designs vary, with large plants such as Bayou Cogen providing eight customers with 1.7 million lbs/hr (.77 million kg/hr) process steam in addition to 300 MW of electric power, and Ocean State Power (2 x STAG 207EA) providing 500 MW to New England consumers, while small cogeneration plants such as TBG Cogen use aircraft derivative gas turbines (2 x LM 2500). GE O&M services can provide third party operations and maintenance services to its customers as well as a direct link to GE technical resources and services.

	MWe	No. GTs		Avg. Availability
Bayou Cogen	300 MW	4	4/85 - 12/93	96.4%
Bayonne Cogen	165 MW	3	10/88 - 12/93	95.6%
Cardinal Cogen	50 MW	1	4/88 - 12/93	93.1%
Powersmith Cogen	110 MW	1	8/89 - 12/93	90.2%
TBG Cogen	50 MW	2	8/89 - 12/93	98.0%
Altresco Cogen	165 MW	3	10/90 - 12/93	96.7%
Ocean State Power	500 MW	4	1/91 - 12/93	94.6%
Selkirk Cogen I	80 MW	1	4/92 - 12/93	93.2%
Mass Power	250 MW	2	7/93 - 12/93	94.1%
Selkirk II	280 MW	3	7/94	N/A

GT22972B

Figure 35. GE O&M Services

EMISSIONS CONTROL

Current worldwide environmental concerns have imposed stack gas emission limits on nearly all thermal power generation plants. The down-

Table 9
EMISSION CONTROL
TREND SETTING EXAMPLES

OWNER	COD	CAPACITY MW	GAS TURBINE	EMISSION LIMITS (ppmvd at 15% 0_2 (g/gJ)) NO$_x$	CO	UHC	VOC	NO$_x$ EMISSION CONTROL
MMWEC	1983	340	MS7001E	75 (130)	–	–	–	Steam Injection
Gaylord Container	1983	36	MS6001B	42 (72)	5 (5)	–	–	Steam Injection
Cool Water IGCC	1984	120	MS7001E	42 (72)	–	–	–	Moisturized Coal Gas
Tokyo Electric Power	1985	2000	MS9001E	10 (17)	5 (5)	5 (3)	–	Steam Injection, SCR
Gilroy Foods	1987	80	MS7001E	25 (43)	5 (5)	5 (3)	2 (2)	Steam Injection
Watson Cogeneration	1988	390	MS7001EA	9 (15)	2 (2)	5 (3)	2 (2)	Steam Injection, SCR CO Catalyst
Cogen Technologies	1988	114	MS6001B	9 (15)	5 (5)	5 (3)	–	Steam Injection, SCR
Ocean State Power	1990	480	MS7001EA	9 (15)	5 (5)	5 (3)	–	Water Injection, SCR
Jersey Central P&L	1991	114	MS6001B	25 (43)	15 (15)	–	–	DLN
Florida P&L	1993	990	MS7001FA	25 (43)	15 (15)	–	–	DLN
Sithe	1994	1042	MS7001FA	4.5 (7.7)	15 (15)	–	–	DLN, SCR

ward trend of regulated oxides of nitrogen (NO_X) in gas turbine exhaust gas presented earlier in Figure 5 is typical of all emissions. Gas turbine and combined-cycle plants have consistently satisfied the increasingly stringent emission requirements by combustion design refinements supplemented by other effective measures. Particulate and unburned hydrocarbon limits have been satisfied by combustor design and fuel selection.

Carbon monoxide (CO) limits are satisfied by the highly efficient, complete combustion in the GE heavy-duty gas turbines except in rare cases where external percentage reduction is mandated. In those rare cases, a CO oxidation catalyst has been installed. CO catalysts have been employed more commonly on the aircraft-derivative gas turbines in applications that require high water or steam injection rates to satisfy stringent NO_X emission limits.

NO_X emission limits have been met by refined combustion design, water injection, steam injection and SCR, which reacts NO_X with ammonia in the presence of a catalyst to reduce NO_X to nitrogen and water. The temperature range for these catalytic reactions is lower than the exhaust temperature of modern gas turbines, so it is convenient to install the catalyst in the HRSG gas path in combined-cycle systems. Recently, combined-cycle systems have been sold with gas turbines incorporating dry low NO_X combustion systems that do not require water or steam injection to satisfy severe NO_X emission requirements. Table 9 presents combined-cycle examples that illustrate the evolution of emission control and the increasing stringency of the limits. Today, more than 350 GE gas turbines are operating reliably with water or steam injection, 85 with SCR, and more than 112 are under contract with Dry Low NO_X combustion systems.

STAG STEAM CYCLE DESIGN EVOLUTION

The first STAG combined-cycle power generation system began commercial operation in 1968, and a second STAG 105, 21-MW unit entered service in 1970. They are single-shaft systems with steam generation at two pressures for admission to the steam turbine throttle and at a lower pressure. The early STAG 103 and STAG 107 systems have single-pressure steam systems. All single-shaft STAG systems have included deaerating condensers with economizers in the HRSGs that perform all feedwater heating.

The early multi-shaft STAG combined cycles with MS7001 gas turbines had single-pressure steam cycles. All had two extraction feedwater heaters, the second being a deaerator. Several had supplemental firing in the HRSG. Extraction feedwater heaters (with natural gas fuel) and HRSG firing have been discontinued in power generation combined cycles because both reduce thermal efficiency. Subsequent multi-shaft STAG systems employed either a deaerating condenser or low-temperature economizers and flash tank to generate steam for a conventional deaerator operating above atmospheric pressure.

STAG combined-cycle steam systems have evolved in response to fuel cost and availability, equipment development, environmental considerations and requirement for high reliability. Table 10 presents a summary of key steam cycle characteristics for the power generation combined cycles. The variability seen in the table results from combining standard equipment modules under various site and economic criteria.

All STAG combined-cycle systems prior to 1985 employed HRSGs with vertical gas flow, horizontal tubes and forced circulation evaporators. Since 1985, HRSGs with vertical tubes, horizontal gas flow and natural circulation evaporators have evolved as the predominant type. Deaerators integral with a low-pressure evaporator and operating above atmospheric pressure have been incorporated into the natural-circulation HRSG.

Currently, nearly all heat recovery combined cycles have steam generation at two or three pressures. The introduction of the MS6001FA, MS7001FA and MS9001FA advanced gas turbines with 1080 F (582 C) exhaust gas temperature has enabled reheat to be applied effectively and economically. The first STAG 107F combined cycle with reheat steam cycle entered service in February 1990 at the Virginia Power Chesterfield Station. The standard steam cycle for application with the MS7001FA and MS9001FA gas turbines is a three-pressure, reheat steam cycle. The MS7001EC and MS9001EC gas turbines can be applied with reheat or non-reheat steam cycles.

COOPERATIVE DESIGN EXPERIENCE

Load cycle, fuel type, site conditions and environmental requirements dictate variations in plant design. Combined-cycle plants, using GE equipment or engineered equipment packages, have been designed in cooperation with many different engineering firms, by GE alone, or solely by engineering firms. GE's system of providing interface information and functional specifications for the coordination has resulted in a consistent quality to match individual customer needs. Examples of GE STAG co-operative design experience are shown in Table 11.

Table 10
GE STAG STEAM CYCLE DATA

PLANT	PLANT TYPE	STEAM CONDITIONS AT SITE PRESS PSIG (ATA)	STEAM CONDITIONS AT SITE TEMP F (C)	STEAM TURBINE LSB–INCHES(MM)
Wolverine Elect. Co-op	(1) STAG 105	400 (28.6) 85 (6.9)	750 (399) 328 (164)	(1) SF-14 (356)
Ottawa Light & Power	(1) STAG 103	400 (28.6)	750 (399)	(1) SF-14 (356)
Clarksdale, MS	(1) STAG 105	400 (28.6) 85 (6.9)	750 (399) 328 (164)	(1) SF-14 (356)
Hutchinson, MN	(1) STAG 103	400 (28.6)	750 (399)	(1) SF-14 (356)
Salt River	(4) STAG 107 B	600 (42.3)	850 (454)	(4) SF-17 (432)
Arizona Pub. Serv.	(3) STAG 107 B	600 (42.3)	860 (460)	(3) SF-17 (432)
Ohio Edison	(1) STAG 207 B	1250 (87.0)	948 (509)	(1) DF-20 (508)
Duquesne Light	(1) STAG 307 B	1250 (87.0)	948 (509)	(1) DF-23 (584)
Iowa-Illinois	(1) STAG 405 L	850 (59.5)	900 (482)	(1) SF-20 (508)
Jersey Central	(1) STAG 407 B	1250 (87.0)	948 (509)	(1) DF-23 (584)
Houston L&P	(2) STAG 407 B	800 (56.1)	844 (451)	(2) DF-20 (508)
Puerto Rico	(2) STAG 407 B	850 (59.5)	860 (460)	(2) DF-20 (508)
Korea	(2) STAG 407 B	850 (59.5)	860 (460)	(2) DF-23 (584)
Portland GE	(1) STAG 607 B	850 (59.5)	860 (460)	(1) 4F-16.5 (419)
Western Farmers	(3) STAG 107 E	600 (42.3)	860 (460)	(3) SF-17 (432)
Cool Water	(1) STAG 107 E	1420 (98.8)	979 (526)	(1) SF-23 (584)
Chubu	(5) STAG 107 E	800 (56.1) 90 (7.2)	911 (508) 324 (162)	(5) SF-23 (584)
TEPCO	(14) STAG 109 E	890 (61.3) 109 (8.5)	950 (510) 343 (173)	(14)SF-26 (660)
Electricidad de Misiones	(1) STAG 205 P	580 (40.8)	875 (468)	(1) SF-14.3 (363)
T&TEC	(1) STAG 207 E	834 (58.5)	950 (510)	(1) SF-23 (584)
Taiwan	(2) STAG 307 E	850 (59.5) 110 (8.6)	950 (510) 173 (343)	(2) SF-23 (584)
MMWEC	(1) STAG 307 E	850 (59.5) 110 (8.6)	950 (510) 373 (173)	(1) DF-23 (584)
CFE	(1) STAG 407 E	885 (62.0) 110 (8.6)	950 (510) 373 (173)	(1) DF-23 (584)
Ocean State Power	(2) STAG 207 EA	1400 (97.4) 70 (5.8)	950 (510) 375 (190)	(2) DF-23 (584)
WAPDA	(2) STAG 209 E	885 (62.0)	960 (515)	(2) DF-23 (584)
Fayetteville	(1) STAG 605 P	800 (56.1)	895 (452)	(1) SF-23 (584)
Egyptian Elec. Auth.	(2) STAG 405 P	800 (56.1)	864 (462)	(2) SF-23 (584)
Virginia Power	(2) STAG 107 F	1342 (93.4) 262 (19.0)	956 (513) 960 (516)	(2) SF-26 (660) RH
TEPCO	(8) STAG 109 F	1418 (98.6) 314 (22.6) 41 (3.9)	1000 (538) 1000 (538) 492 (255)	(8) DF-26 (660) RH
KEPCO	(8) STAG 107 F	1340 (93.2) 290 (20.9) 40 (3.7)	1000 (538) 1000 (538) 478 (248)	(8) SF-33.5 (851)
TECO Power Services	(1) STAG 207 EA	1250 (87.0) 65 (5.5)	933 (501) 400 (204)	(1) DF-23 (584)
Derwent	(1) STAG 406 B	972 (68.0) 90 (7.2)	888 (476) 437 (225)	(1) SF-26 (660)
Pyongtaek	(1) STAG 407EA	1232 (85.8) 289 (20.9) 100 (7.9)	922 (494) 483 (250) 398 (203)	(1) DF-33.5 (851)
China Light & Power	(8) STAG 109FA	1472 (102.4) 57 (4.9)	965 (518) 530 (277)	(8) SF-41.3 (1049)
Samalayuca	(3) STAG 107FA	1380 (96.1) 291 (21.1) 26 (2.8)	1000 (538) 1000 (538) 474 (246)	(3) SF-20 (508)RH
Maura Karang	(1) STAG 309E	1240 (86.4) 81 (6.6)	950 (510) 580 (304)	(1) DF-33.5 (851)
Tampa Electric	(1) STAG 107FA	1385 (96.4)	1000 (538)	(1) DF-26 (660)

Table 11
EXAMPLES OF GE STAG COOPERATIVE DESIGN EXPERIENCE

Utility	Architect/ Engineer
Houston L & P	Ebasco Services
Ohio Edison	Commonwealth Assoc.
Duquesne Light	Gibbs & Hill
Arizona Public Service	Commonwealth Assoc.
Iowa-Illinois	Stanley Consultants
Jersey Central	Burns & Roe
Portland GE	Ebasco Services
Western Farmers	Sanderson & Porter
MMWEC	Bechtel
Taiwan Power	Gibbs & Hill
SCE Cool Water	Bechtel
TEPCO	Toshiba/Hitachi
MPI Lama Dien II	DPA Design Institute
Chubu	Toshiba
Ocean State Power	Ebasco
Virginia Power	JA Jones
EGAT	Toshiba/Sargeant & Lundy
TEPCO-ACC	Hitachi/Toshiba
KEPCO	Gibbs & Hill/KOPEC
TECO Power Services	Black & Veatch
CFE-Mexico	Bechtel
PLN-Indonesia	Black & Veatch
SCECO	Beleli
Sithe	Ebasco
U.S Gen Co./Hermiston	Bechtel

COAL/OIL GASIFICATION COMBINED CYCLES

Many systems have been developed for coal-fired combined cycles, including Integrated Coal Gasification (IGCC), Fluidized Bed Air Cycles (AFB Air) and Pressurized Fluidized Bed Combustion (PFBC). While each of these systems or future variations may eventually become operational, GE has commercial operating experience only with IGCC. The IGCC (Figure 36) integrates various gasification processes with the combined cycle to provide a coal-fired power plant with exceptional environmental characteristics, competitive first cost and improved efficiencies. GE built its first gasification facility in 1975 to test IGCC components. This initial effort led to a commercial plant in 1984. The first IGCC plant was built in California at the Cool Water Site (Figure 37). It included a STAG 107E which produced 120 MW of power from coal fuel. The combined cycle (Figure 38) and station control portion was specifically designed by GE to integrate with the gasifier allowing control of the electricity production from a central control room familiar to power generation operators. The plant operated successfully for over 27,000 hours with an 80% on-stream factor after the early testing program. The experience shows that GE gas turbines can be adapted for coal gas with minor changes including retrofitting in the field.

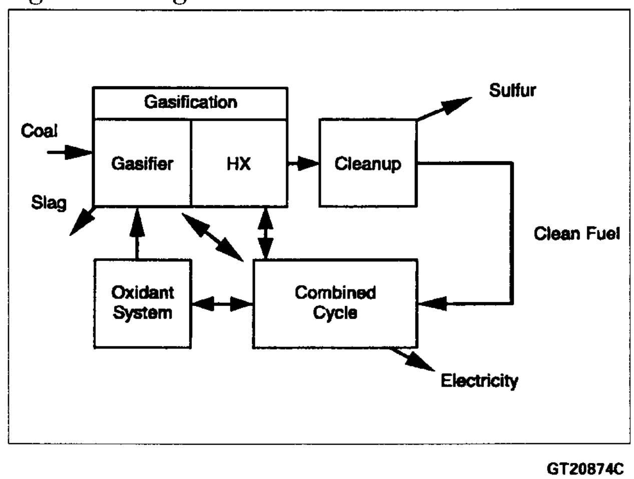


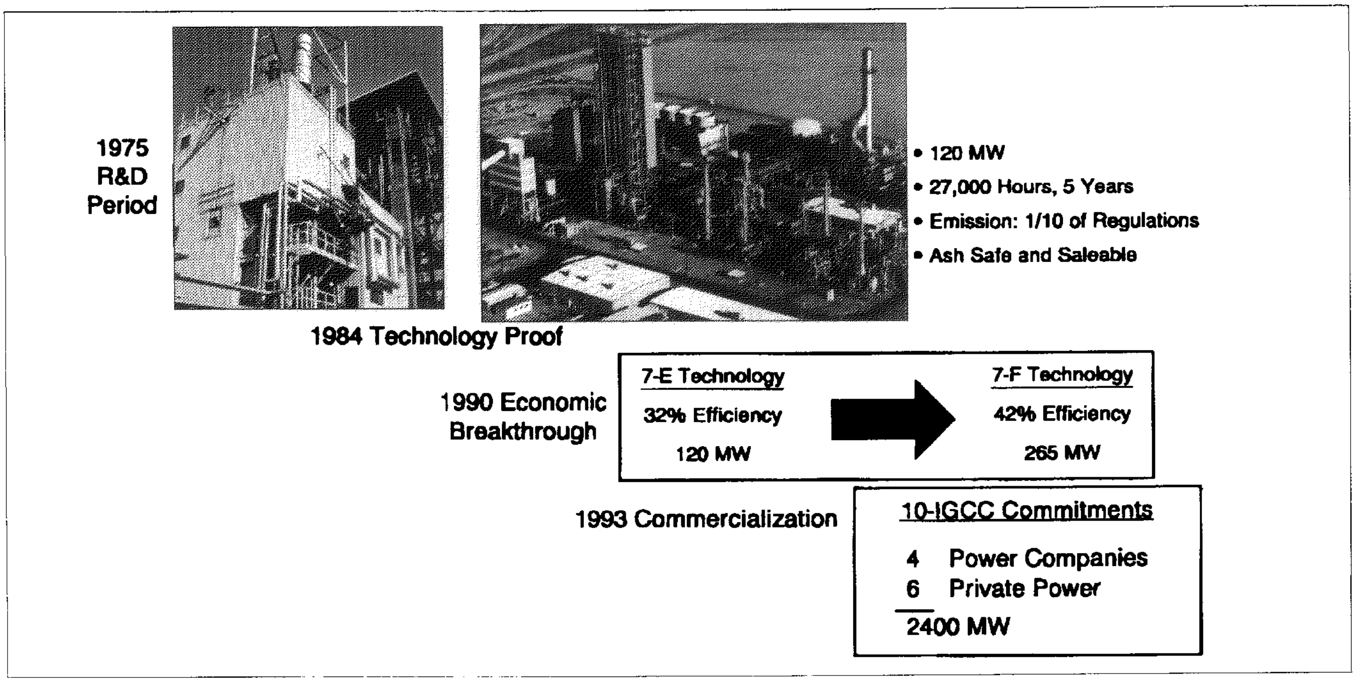
Figure 36. IGCC cycle

Environmental performance of the Cool Water Project was superior — approximately 1/10th of the current USA standards. In addition, no limestone is used and the ash disposal is simple because it is non-leachable.

The technology was deemed successful but not economic due to its 32% thermal efficiency and small size. The commercial introduction of GE's model F gas turbines in 1990 moved IGCC technology forward from 32% thermal efficiency to over 42% and increased the size to 265 MW for 60-cycle systems and 380 MW for 50-cycle systems. Since 1990, 10 different IGCC projects have proceeded utilizing GE gas turbines.

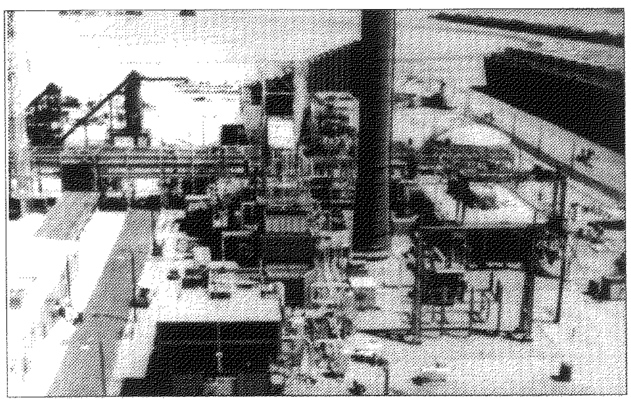
Currently, there are 13 gasification systems with different processes, coal feed methods, oxidants, heat integration and cleanup methods. Two of these can utilize heavy waste oils as well as petroleum coke and coal. As a result of conservative compressor and turbine design and combustion system testing and development, GE gas turbines are compatible with fuel from any of these gasifiers.

IGCCs utilizing GE's MS7001FA, MS9001FA and MS6001FA gas turbines provide performance and environmental benefits that make them an



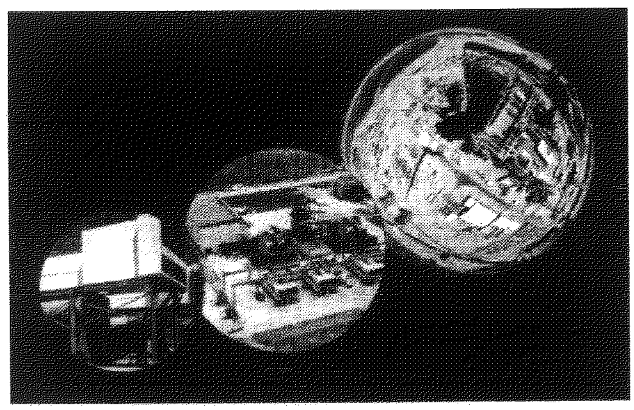
GT24139C

Figure 37. IGCC commercialization program



GT12021-2A

Figure 38. Cool Water combined cycle



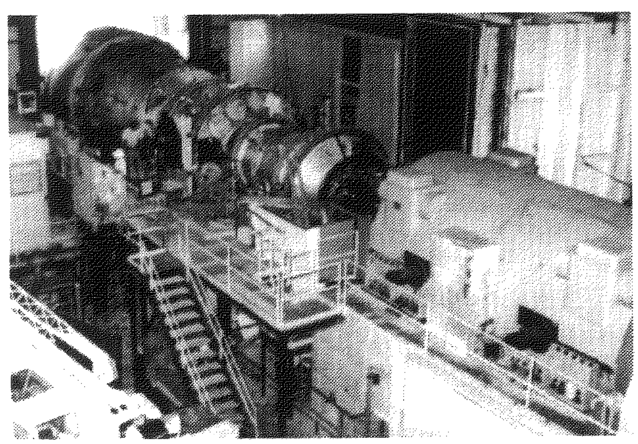
GT15237-3

Figure 40. Progressive Generation (PROGEN)

Customer	Date	MW	Application	Gasifier
PSI Energy	1995	265	Repower/Coal	Destec
Tampa Electric	1996	265	Power/Coal	Texaco
Sierra Pacific	1996	100	Power/Coal	KRW
Texaco El Dorado	1996	40	Cogen/Pet Coke	Texaco
SUV/EGT	1996	450	Cogen/Coal	Lurgi
Shell Pernis	1997	80	Cogen/H_2/Oil	Shell
TBA	1998	350	Cogen/Oil	Shell
Duke Energy	1999	480	Repower/Coal	BG Lurgi
Delaware	1999	250	Cogen/Pet Coke	Texaco
TAMCO	1999	120	Cogen/Coal	Tampella
		2,400		

GT24143D

Figure 39. GE IGCC projects



GT20077

Figure 41. Virginia Power MS7001F gas turbine

economically viable alternative for coal. IGCC economics can be enhanced by the 192-MW capability of the MS7001FA gas turbine and the 275 MW capability of the MS9001FA on syngas. By arranging the IGCC system, GE gas turbines generally produce 20% more output on syngas than on natural gas. This feature is utilized in many of the 10 current IGCC projects being developed using GE turbines and systems (Figure 39). These projects use seven different gasifier technologies to optimize the performance of the various fuels.

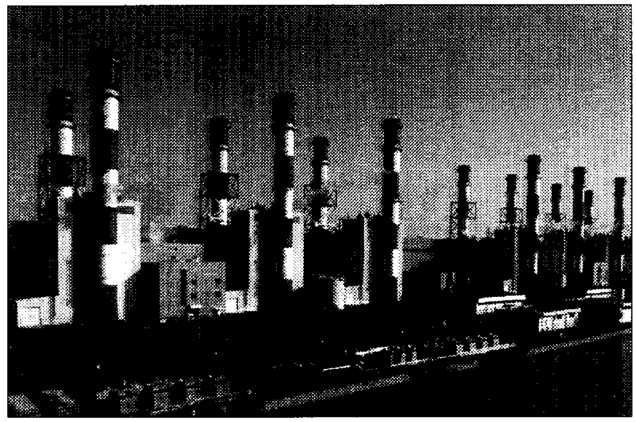
Progressive Generation (PROGEN, Figure 40) enables phased additions to meet power demands closely. PROGEN is simple-cycle gas turbines to satisfy the initial load growth, conversion to combined cycle when the gas turbine load factor rises above 15% to 20%, and conversion to coal gasification when economics dictate. Many USA utilities have based their next additions on this unique capability of the combined cycle.

Virginia Power is operating two STAG 107F combined-cycle systems that incorporate the first MS7001F gas turbine (Figure 41). Studies have confirmed the feasibility of converting these combined-cycle units to IGCCs. Potomac Electric Power (PEPCO) has purchased four MS7001F gas turbines to be installed in a plant that is suitable for integration into a combined-cycle system with subsequent conversion to an IGCC. The first gas turbine went commercial in 1992.

Advanced Combined-Cycle Experience

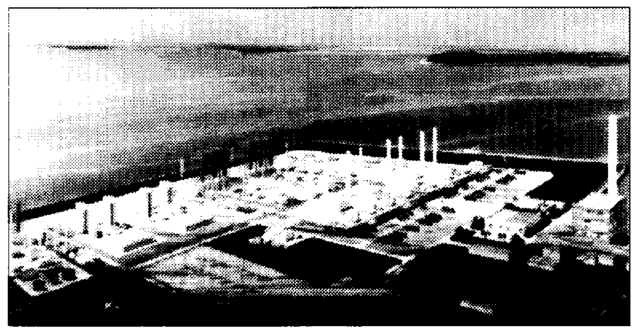
The MS7001FA and MS9001FA advanced gas turbines and the STAG combined-cycle systems incorporating them represent a prudent combination of advanced technology and proven design. Features demonstrated during 40 years of experience result in reliable plants with 54% to 55% (LHV) thermal efficiency. Acceptance of the advanced gas turbines has been demonstrated with commitment for 96 of these units. The first STAG 107F started commercial operation in June 1990 at the Virginia Power Chesterfield Station.

The first advanced gas turbine and its generator, from commercial operation date through its two year introduction period achieved an availability of 97%. A second STAG 107F, Chesterfield #8, has also started commercial operation, and the two units have totalled 30,800 fired hours. Eight similar multi-shaft STAG 107F units have been operating at the Korea Electric Power Company Seoinchon Station (Figure 42). This plant is the most efficient plant operating, with a tested gross efficiency of more than 55% (LHV) on natural gas fuel. The Florida Power and Light Martin Station (Figure 43) went commercial in 1993. This plant utilizes four MS7001FA gas turbines and two 150MW reheat steam turbines.



RDC26977-159

Figure 42. Korea Electric Power Company (Seoinchon Station)



GT22134

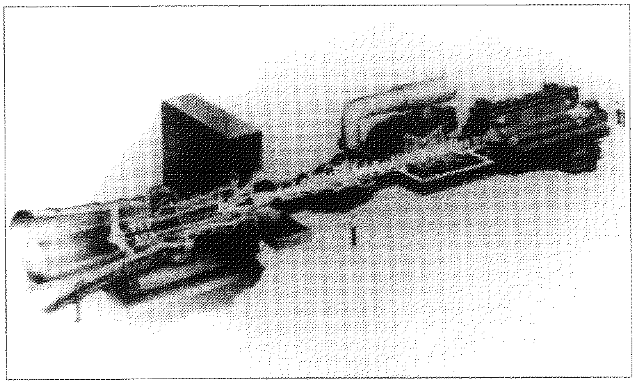
Figure 43. Florida Power & Light (Martin Station)

The Sithe Independence Station project is scheduled for commercial operation November 1, 1994, two months ahead of schedule. The plant is comprised of two STAG 207FA blocks of power, designed for operation on natural gas fuel with Dry Low NO_x combustion and selective catalytic reduction systems to achieve NO_x down to 4.5 ppmvd (7.7g/GJ) ref. 15% O_2. The steam cycle is a three-pressure reheat with deaerating condenser, and capability to supply 200,000 lb/hr (91,000 kg/hr) of process steam at low ambient conditions.

Including the MS9001F in France, there are currently 21 model Fs operating, with an experience base of more than 128,000 actual fired hours and 6,800 starts.

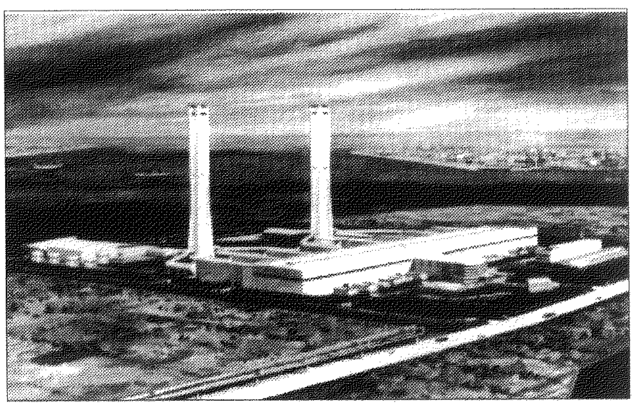
The reheat steam systems applied on the advanced combined cycles to achieve high thermal efficiency operate best with one HRSG matched to one steam turbine in accordance with conventional steam plant practice. The single-shaft STAG combined-cycle incorporates this feature with control and operation simplicity. The turbine-generator equipment for a STAG 109FA unit is shown in Figure 44. The Tokyo Electric

Power Company 2800-MW plant with eight single-shaft STAG 109FA units is in the design phase and the first two units are scheduled for commercial operation in 1996, with all eight units operational in 1998 (Figure 45). These units will operate in daily start/stop operation with weekend shutdowns. The starting method chosen was static start with steam roll. NO_X emissions will be reduced by Dry Low NO_X and dry ammonia SCRs to 5 ppmvd at 16% oxygen (9 g/gJ) at full load.



GT20907C

Figure 44. Single-shaft STAG 107FA/109FA



GT21775-1

Figure 45. TEPCO-ACC plant

The first MS9001F gas turbine was constructed and run satisfactorily in Greenville, South Carolina, in August 1991. The second MS9001F was built by EGT and put into simple cycle service at Electricite De France's Gennevelliers Station. In early 1993, the unit went commercial following a rigorous reliability test run structured for the customer's cycling requirements. The 30-day, non-interruptible test run consisted of 15 days of tests with one start per day and running eight hours per day, immediately followed by another 15 days of two starts per day and one running hour per test. Besides high starting and running reliability, the MS9001F has been designed for the same high availabilities experienced with other GE gas turbines in combined cycle.

CONCLUSION

The GE combined-cycle experience is extensive and worldwide, including 41,000 MW of installed capacity with more than 30,000,000 hours of gas turbine operation. The efficiency, availability and reliability have been outstanding. The GE technology leadership will continue to improve the economic benefits in response to the needs of the power generation and cogeneration industries.

LIST OF FIGURES

LIST OF TABLES

For further information, contact your GE Field Sales Representative or write to GE Power Generation Marketing

GE Industrial & Power Systems

General Electric Company
Building 2, Room 115B
One River Road
Schenectady, NY 12345

9/94 (500)