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COMBINED-CYCLE POWER PLANT EXPERIENCE IN PAKISTAN AND EGYPT

Final Report

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CONTENTS

EXECUTIVE SUMMARY

CHAPTER 1: INTRODUCTION

CHAPTER 2: AN INTRODUCTION TO COMBINED-CYCLE TECHNOLOGY

2.1 The Combined-Cycle System 2.1
2.2 Combined-Cycle Technology Potential 2.1
2.3 Technology Performance 2.3
2.4 System Advantages and Disadvantages 2.12

CHAPTER 3: GUDDU POWER PLANT, PAKISTAN

3.1 Construction History 3.1
3.1 Plant Design 3.4
3.3 Plant Operations 3.10

CHAPTER 4: TALKA POWER PLANT, EGYPT

4.1 Construction History 4.1
4.2 Plant Design 4.2
4.3 Plant Operations 4.4

CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

5.1 Case Study Conclusions 5.1
5.2 Recommendations for Electric Utilities in Developing Countries 5.3
5.3 Recommendations for International Donors 5.6

APPENDIX A: GUDDU PLANT OUTAGE RECORDS

APPENDIX B: GUDDU PLANT PERFORMANCE CURVES

APPENDIX C: TALKHA PLANT OPERATIONS

APPENDIX D: DEFINITIONS

TABLES

1. Combined-Cycle Plants Installed by General Electric 2.4
2. Combined-Cycle Planned Outages -- Recommended Inspection Intervals for GE Plants 2.7
3. Predicting Combined-Cycle Forced Outages -- Estimated Repair and Replacement Costs for GE Plants 2.8
4. Gas Turbine Operating Inspection Data Parameters 2.11
5. Guddu Plant Availability, Generation, and Station Heat Rates 3.12
6. Guddu Plant: Capacity and Utilization Factor 3.13
7. Guddu Station Annual Availability and Heat Rates 3.19
8. Chronology of Plant Outages Greater than 100 Hours in Duration 3.20
9. Ten Longest Outages at Guddu Power Station by MWh Lost 3.28
10. Guddu Plant: Availability, Forced and Planned Outage Rates 3.29
11. Guddu Plant: Recent Typical Day Statistics 3.30

3

FIGURES

1. Combined-Cycle Power Plant Configuration 2.2
2. Factors Contributing to Combined-Cycle Plant Unavailability 2.6
3. Estimated Effect of Load and Starts on Gas Turbine Maintenance 2.9
4. Estimated Effect of Fuel Type on Maintenance 2.10
5. Inherent Availability 2.12
6. Typical Project Schedule 2.14
7. Growth of STAG Combined-Cycle Power Plant Efficiency 2.15
8. Location of Guddu Power Plant 3.2
9. Guddu Site Plan 3.5
10. Typical STAG GE Combined Cycle Plant Configuration 3.6
11. Distributed Control and Information System 3.9
12. Guddu Plant Generator and Station Availabilities 3.14
13. Factors Affecting Availability 3.23
14. Guddu Station: Top Five Systems Contributing to Gas Turbine Downtime 3.24
15. Guddu Plant Utilization Factor vs. Heat Rate 3.25
16. Guddu Plant Availability vs. Heat Rate 3.26
17. Talkha Plant Capacity Factor vs. Heat Rate 4.7

4

EXECUTIVE SUMMARY

Modern combined-cycle plants produce electricity from two generators: a combustion turbine generator (usually fired by natural gas) and a steam turbine generator, the steam for which is generated from the hot exhaust gas of the combustion turbine. This technology is an efficient way for developing countries with abundant supplies of natural gas (or associated gas that is now being flared at oil production facilities) to promote the development of gas as a clean fuel, while addressing the need for power sector expansion in the 1990s.

While combined-cycle technology has been proven and is being widely used in industrialized nations, because it is still relatively new, utilities in some developing countries are proceeding cautiously toward its use. Their concerns center around the potential reliability of combined-cycle power stations, given the apparent "doubled" complexity of combined cycles (two generating units) and the advanced high-temperature materials technology used in today's gas turbines.

To address these concerns, the Office of Energy of the U.S. Agency for International Development, together with the Multi-Agency Working Group on Power Sector Innovation (MAGPI) and the World Bank, is sponsoring studies to document the world-wide experience of combined-cycle technology. As part of these studies, the Energy Conservation Services Program of the Office of Energy was tasked to document the operating experience of A.I.D.-funded combined-cycle power projects in the Islamic Republic of Pakistan and the Arab Republic of Egypt. The results of this study can assist utility planners in other developing countries to evaluate the potential for this technology in their own systems. It should be cautioned however, that this study was performed on only two utilities with very limited plant experience. Definitive conclusions on the performance of combined-cycle technology cannot be made.

Guddu Power Plant, Pakistan

The plant examined in greatest detail for this study is the 600 MW Guddu Combined Cycle Power Station in Pakistan. This plant has the longest history of operation of any combined-cycle plant in an A.I.D.-assisted developing country. The Guddu plant is owned and operated by the Water and Power Development Authority (WAPDA) of the Government of Pakistan.

The Guddu plant, which has a nameplate capacity of 600 MW, is located approximately 600 km from Karachi. The plant was commissioned and constructed for a total cost of U.S. $296 million. Following a competitive bidding procedure, General Electric Company

of Schenectady, New York, was awarded the contract for construction of the plant. Gibbs and Hill prepared the plant design and specifications, and acted as engineers and managers for the project. Construction on the plant began in July 1983 and concluded in March 1988. The project, including testing, was completed in November 1988. The gas turbine generators G-7, G-8, G-9, and G-10 were commissioned in December 1985, April 1986, March 1986, and April 1986, respectively. The steam turbine generators were commissioned in January and March 1988, respectively.

The plant's physical configuration consists of four gas turbines, four heat recovery steam generators (HRSG), and two steam turbines. The GE gas turbine and the HRSGs are designed to be operated as baseload units. The plant's operations, from January 1988 to February 1990, can be summarized as follows:

Guddu Station Annual Availability, Heat Rate, Efficiency and Forced Outage Rate

Year	GTG Availa-bility	STG Availa-bility	Station Availa-bility	Net Station Heat Rate (Btu/kWh)	Efficiency (%)	Forced Outage Rate (%)
1988	77%	73%	76%	9,309	37	12
1989	76%	76%	76%	9,290	37	14
1990*	96%	99%	97%	8,281	41	2
26-month average	83%	83%	83%	8,960	38	12

*Data for 1990 cover the two-month period January-February only, which were months of steady operation. It is not expected that performance for the entire year was this good.

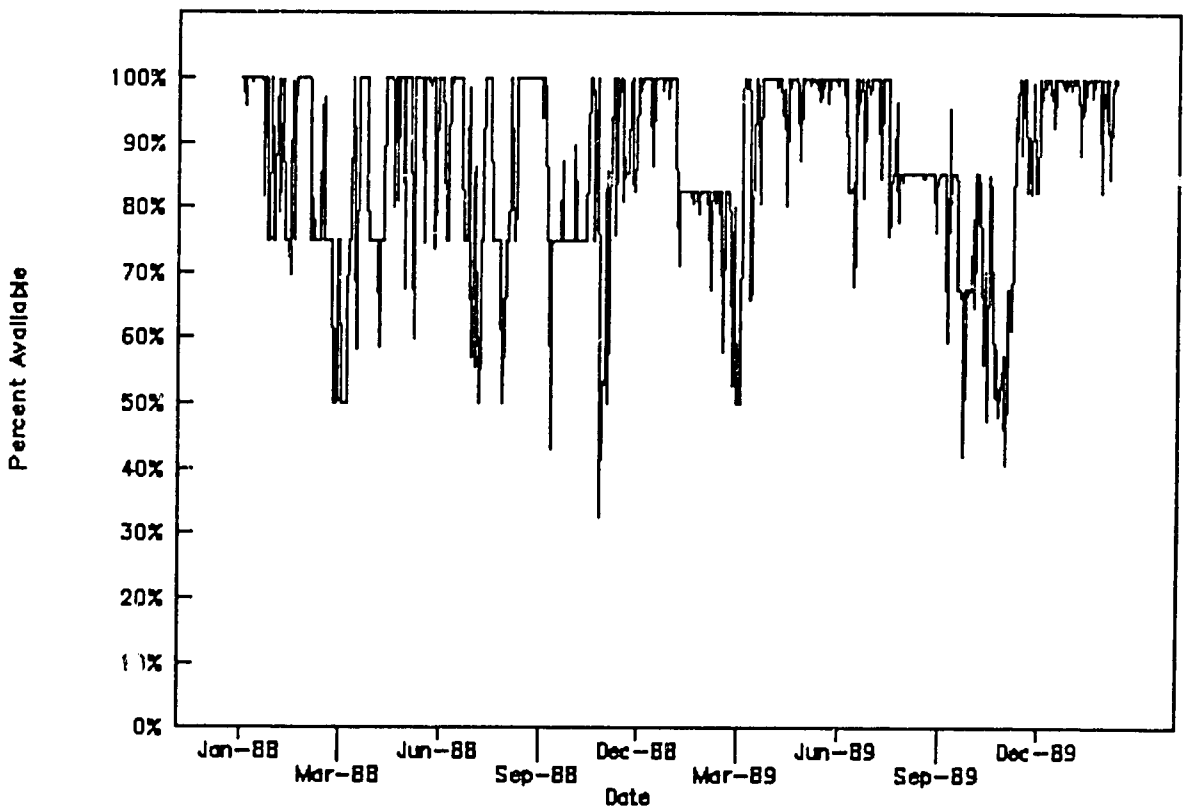
Note: GTG = gas turbine generator
STG = steam turbine generator

Averages for the year 1988 reflect September through December only, the forced outage rate is a 15-month average.

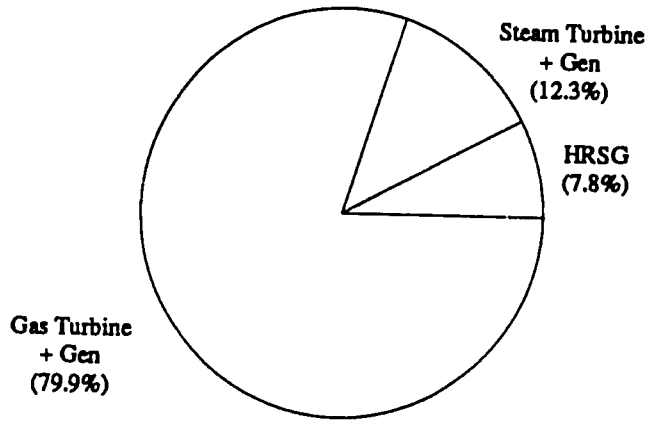
All heat rates and efficiencies are calculated on the basis of the low heating value of natural gas.

Guddu Station Availability

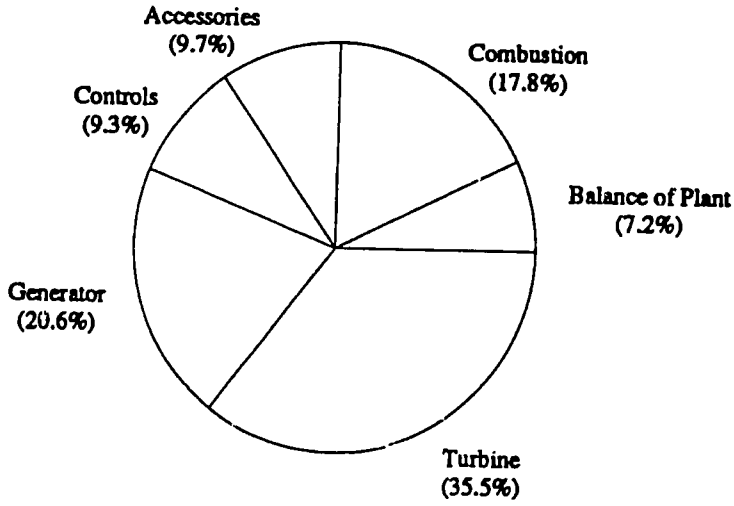
(Station Average is 83 Percent Over an Operating History of 26 Months)



Guddu 600 MW: Subsystems Contributing to Combined Cycle Plant Unavailability



Guddu 600 MW: Subsystems Contributing to Gas Turbine Plant Unavailability



Talkha Power Plant, Egypt

The second plant examined was the 300 MW combined-cycle Talkha Power Plant, which is located about 120 km from Cairo, Egypt. The plant is owned and operated by the Egyptian Electricity Authority (EEA).

The Talkha plant was previously a simple-cycle gas turbine station, and was converted to combined cycle by installing the HRSG and steam turbine generator for a total cost of U.S. $70.3 million. General Electric converted the gas turbine-powered generating station into the country's first combined-cycle power plant, increasing its capacity from 200 MW to 300 MW. The Talkha plant began commercial operation in August 1989.

The plant is designed to operate as a baseload unit, as a spinning reserve unit, or as a part-load unit, and the generation equipment can be operated in a simple- or combined-cycle mode. The plant is designed to be fueled by natural gas or distillate fuel oil, and plant output is slightly derated when oil-fired.

Only a limited amount of information was available on the operations of the Talkha plant, which had been in combined-cycle operation for only five months when the EEA responded to requests for data for this study. Operating experience for this plant can be summarized as follows:

Talkha Station Availability, Heat, and Efficiency

1989	GTG Availability	STG Availability	Station Availa-bility	Net Heat Rate (Btu/kWh)	Efficiency (%)
August	87%	88%	87%	10,057	34
September	97%	67%	87%	11,427	30
October	87%	54%	76%	12,069	28
November	86%	86%	86%	10,443	33
December	88%	86%	87%	10,357	33
Average	89%	76%	85%	10,871	31

Note: GTG = gas turbine generator
STG = steam turbine generator

.9

Conclusions

Combined-cycle power plants have been installed in Pakistan and Egypt under A.I.D.-assisted projects. These installations have a demonstrated track record, and can serve as case studies for other countries. The early performance of these plants provides the basis for a number of conclusions:

Compared to coal-fired steam plants, natural gas combined-cycle technology has now been demonstrated to have a number of advantages in developing countries:

- Lower Capital Costs per Megawatt: The 600 MW Guddu project cost $500 per kilowatt (1982 US$), whereas a standard pulverized coal plant of the same rated capacity would have cost $800 per kilowatt at the time. In 1990 US$, the cost of combined-cycle technology is about $600 per kilowatt, whereas competing coal technologies cost $1200 per kilowatt (inclusive of additional environmental controls) or more.

- Shorter Construction Schedule: The Guddu project delivered power from its first generator some 31 months after construction began, whereas a coal-fired station would probably have required 48 months.

- Similar Availability: Average availability for the Guddu plant during the study period was 83 percent in the combined-cycle mode, which is about the same as that for WAPDA's steam stations.

- Higher Efficiency: Guddu's thermal efficiency averaged 38.5 percent over the study period, which compares favorably with an average of 34 percent for new U.S. coal-fired plants and 30 percent for WAPDA's existing steam stations.

- Reduced Environmental Impact: Natural gas combustion produces lower emissions of sulfur oxides, nitrogen oxides, and carbon dioxide than coal-firing.

Compared to those in industrialized countries, combined-cycle plants in developing countries have experienced lower availability and efficiency. This may have been due to cautious operation, because of the novelty of the technology. However further investigations are required before definite conclusions can be reached.

Operations in a power shortage situation induce stresses that may affect long-term reliability or equipment life. An urgent need for the electric power from the plant may result in decisions to delay preventive maintenance activities or to operate at reduced load, instead of taking a forced outage in response to instrument readings for which the manufacturer recommends corrective action. This is, of course, a factor that affects any power generation equipment, not just combined cycle plants.

Recommendations

Arising from these conclusions, the following recommendations are made for electric utilities in developing countries:

- Use the experience obtained at Guddu and Talkha to develop estimates of performance for combined-cycle plants.
- Evaluate projects to retrofit existing gas turbine power stations to combined cycle, depending on the load forecast and generation expansion plan.
- Evaluate combined-cycle technology in comparison to alternative gas-fired generation. Such an evaluation can also be used to coordinate power sector expansion planning with gas development.

For international donors, the following recommendations are offered:

- Develop a system of tracking and documenting the experience of developing countries with specific technologies in the energy sector, including combined cycle.
- Continue the detailed longitudinal study of Guddu and Talkha, by yearly updates.
- Provide support to human resource development to support combined-cycle technology, such as regional workshops for electric utility system planners and training programs for engineers, operators, and maintenance staff, focused on internships in combined-cycle plants in industrialized countries.

11

CHAPTER 1: INTRODUCTION

Many oil-producing developing countries have abundant supplies of natural gas, or associated gas that is now being flared at oil production facilities, which is not yet being economically used as a fuel. For these countries, the World Bank has targeted combined-cycle technology as an effective way to promote the development of gas as a clean fuel, while addressing the need for power sector expansion in the 1990s.

Modern combined-cycle plants produce electricity from two generators: a combustion turbine generator (usually fired by natural gas) and a steam turbine generator, the steam for which is generated from the hot exhaust gas of the combustion turbine. While combined-cycle technology has been proven and is being widely applied in industrialized nations, because it is still relatively new, utilities in some developing countries are proceeding cautiously toward its use. In particular, these utilities have questioned the potential reliability of combined-cycle power stations, given the apparent "doubled" complexity of the combined cycle (two generating units), and the advanced high-temperature materials technology used in today's gas turbines. These concerns arise from the constraints inherent in the developing country environment -- shortages of skilled manpower limited operating and maintenance staff, lack of access to the best repair shops, tools and other maintenance facilities, and even shortages of foreign exchange for spare parts.

To address these concerns, the Office of Energy of the U.S. Agency for International Development (A.I.D.), together with the Multi-Agency Working Group on Power Sector Innovation (MAGPI) and the World Bank, is sponsoring studies to document the world-wide experience with combined-cycle technology. As part of this study, the Energy Conservation Services Program of the A.I.D. Office of Energy was tasked to document the operating experience of the A.I.D.-funded combined-cycle power projects in Pakistan and the Arab Republic of Egypt. This information regarding the availability, efficiency, and utilization of combined-cycle powerplants can assist utility planners in other developing countries to evaluate the potential for this technology in their own systems.

This study documents and evaluates the operating experience of two individual plants. The first is the 600 MW combined-cycle power plant in Guddu, Pakistan, which is owned and operated by the Water and Power Development Authority of Pakistan (WAPDA). The second is the 300 MW Talkha power plant in Egypt, which is operated by the Egyptian Electricity Authority (EEA).

Chapter 2 of this report provides an introduction to the technology used in combined-cycle systems. Chapter 3 describes Pakistan's Guddu plant, with an emphasis on its operation

and maintenance history, and Chapter 4 describes Egypt's Talkha plant. Chapter 5 presents the study team's conclusions and recommendations based on detailed plant records and observations.

CHAPTER 2: AN INTRODUCTION TO COMBINED-CYCLE TECHNOLOGY

2.1 THE COMBINED-CYCLE SYSTEM

A combined-cycle power plant is an electric power generation system in which heat released through the combustion of fuel effectively passes through two thermodynamic cycles that are connected in a series. Modern plants are based on the combustion turbine (gas turbine).

In the topping (high temperature) cycle, the heat passes through a gas turbine-generator (Brayton cycle), which is fired by natural gas. In emergencies, these turbines can be fired with distillate petroleum products (such as jet fuel, kerosene, or diesel oil), but these fuels are generally not economic.

The hot exhaust gas leaving this turbine passes through a heat recovery steam generator (HRSG, or waste heat boiler), where the heat is transferred to water to make steam. This steam is used to drive a steam turbine-generator in the lower temperature (bottoming) Rankine cycle. The HRSG is an unfired boiler that includes evaporator, superheater, and economizer sections, and is slightly larger in size than a standard utility boiler. As in a standard steam power cycle, after leaving the turbine the steam is condensed under extreme vacuum in a condenser (an air- or water-cooled heat exchanger), pressurized in a boiler feedwater pump, and returned to the HRSG to be evaporated and super heated. Figure 1 displays a simplified block diagram of a combined-cycle power plant.

2.2 COMBINED-CYCLE TECHNOLOGY POTENTIAL

Combined-cycle plants have been in operation since the 1940s. As the technology has developed, its reliability and efficiency have improved dramatically, especially in the past decade. One driving force behind this change was the lifting in 1978 of a U.S. federal ban on using natural gas for power generation in other than peaking units. Since that time, U.S. utilities have aggressively pursued gas turbines in order to meet their growing peak demands for electric power. A natural extension to these systems results from the installation of the HRSG and steam turbine, thereby upgrading a peaking plant into an intermediate, or even baseload, station.

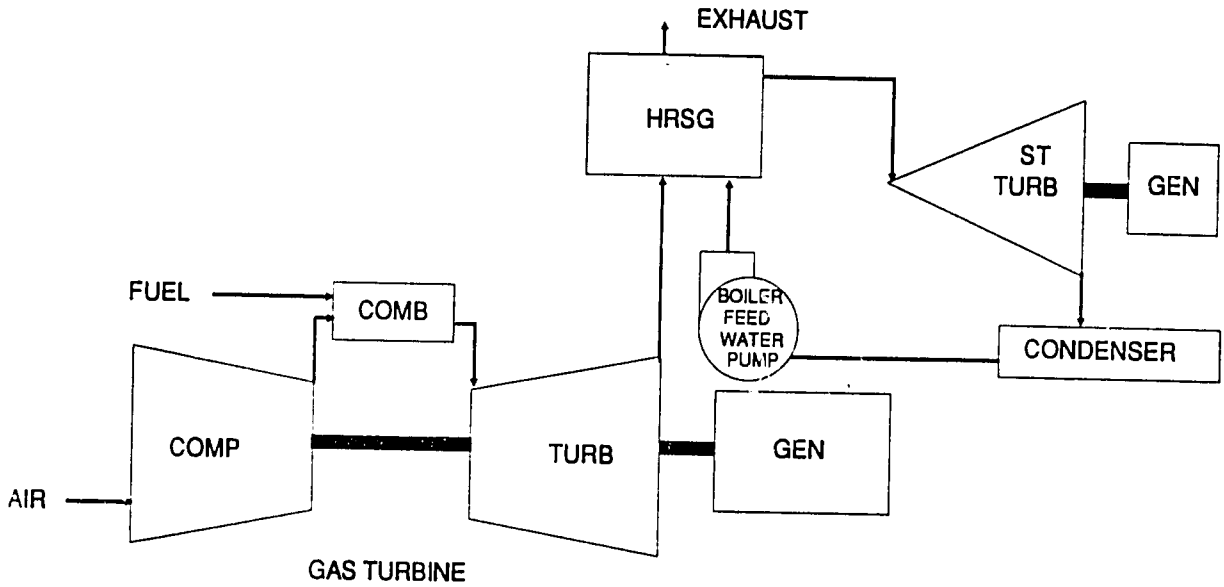


Figure 1. Combined-Cycle Power Plant Configuration

Source: Derived from R.P. Allen and R.P. Triassi, "GE Gas Turbine Performance Characteristics," General Electric Company, Schenectady, New York, 1989.

While relatively new to the electric utility industry, combined-cycle technology is practically identical to the gas turbine-based cogeneration technology often used in industrial plants, particularly in the chemicals industry. For example, in modern ammonia plants,[1] electric power is generated in a gas turbine generator and high-pressure (40 bar, 600 psi) superheated steam is generated in the HRSG; this steam is used to drive large backpressure steam turbines which power process gas compressors, with the exhaust steam then being used for process heating. By using condensing steam turbines instead of the process heating loop, combined-cycle power technology in fact represents a simplification of this cogeneration system, which is running reliably in ammonia and other plants in developing countries around the world.

The Gas Research Institute has estimated that over two-thirds of the 12,000 MW of U.S. cogeneration capacity added between 1980 and 1987 was based on gas turbines. In addition, Westinghouse estimates that U.S. gas turbine-driven capacity, including both simple- and combined-cycle units, will account for nearly 60 percent of the electric utility

[1] As designed by M.W. Kellogg Co., and operated in over 200 sites around the world.

added in the U.S. in the 1990s. Thus, it is evident that combined-cycle plants and gas turbine-based cogeneration have been a technological and market success in the United States.

The General Electric Company of the U.S. (GE) has built more combined-cycle turbines than any other company. GE estimates that it has designed and installed over 100 combined-cycle power plants in the last decade.[2] Because both of the plants studied in this report (Guddu in Pakistan and Talkha in Egypt) use GE technology, this report focuses on the GE experience. Other countries of interest in which GE installed these plants include Korea, Japan, Argentina, and Taiwan.

At present, GE has a total of approximately 21,000 MW of combined-cycle capacity installed worldwide. Of this, the GE turbine used at Guddu -- the Frame 9 -- accounts for 6,000 MW of capacity. GE designates its combined-cycle plants as STAG (steam turbine and gas turbine). Table 1 shows the location, basic configuration, and performance hours of GE STAG plants worldwide.

2.3 TECHNOLOGY PERFORMANCE

Plant Availability

Availability means whether a unit can be committed to serve a load. This includes units that are in cold reserve, hot reserve, or ready for dispatch. Availability is the probability of the unit being available, independent of whether or not the unit is needed, and includes all unavailable hours.

$$\text{Availability} = \frac{\text{MWh dispatchable}}{\text{Total MWh capable in time period}}$$

Note: The total MWh capable in the time period should be computed with reference to the ambient temperature during the time period as is done in this study.

However, in order to account for the partial availability of a unit, availability is calculated as the ratio between the dispatchable energy over a given time period and the total energy

[2] Personal communication with John Romaniuk, Customer Engineering, General Electric Company, Schenectady, New York, 1990.

16

Table 1. Combined–Cycle Plants Installed by General Electric

Country	Utility	No. GT's	No. ST's	Total MW	Commercial Operation	Total GT Hrs (May 1990)
USA	City of Ottawa	1	1	11	1968	100,000
USA	Wolverine Electric	1	1	21	1968	133,000
USA	City of Clarksdale	1	1	21	1972	117,000
USA	City of Hutchinson	1	1	11	1972	68,000
USA	Duquesne P&L	3	1	330	1974	47,000
USA	Houston P&L	8	2	584	1974	534,000
USA	Salt River Project	4	4	288	1974	117,000
USA	Ohio Edison	2	1	225	1974	50,000
USA	Arizona Public Com.	3	3	249	1977	68,000
USA	Iowa Illinois G&E	4	1	105	1977	150,000
USA	Jersey Central	4	1	340	1977	126,000
USA	Puero Rico EPA	8	2	584	1977	167,000
USA	Western Farmers	3	3	300	1977	187,000
USA	Portland G&E	6	1	550	1977	15,000
Korea	Korea Electric	8	2	584	1979	76,000
USA	MMWEC	3	1	340	1983	54,000
Taiwan	Taiwan Power Co.	6	2	600	1983	32,000
Mexico	CFE	4	1	371	1984	201,000
Argentina	EMSA	2	1	60	1984	33,000
USA	SCE CoolwaterIGCC	1	1	100	1984	27,000
Trinidad	Trinidad&Tobago	2	1	198	1985	54,000
Japan	Tepco Group 1	7	7	1,001	1988	96,000
Japan	Tepco Group 2	7	7	1,001	1986	25,000
China	MPI LamaDien II	1	1	50	1988	57,000
Pakistan	WAPDA	4	2	600	1986	21,000
Japan	Chubu Electric Powe	5	5	560	1988	35
USA	Fayettville	6	1	180	1988	phase 1 ready
Egypt	Egyptian Elec. Auth.	8	2	300	1988	phase 1 ready
USA	Ocean State Power	4	2	480	1989	construction
USA	Virginia Power	2	2	420	1990/92	phase 1 ready
Thailand	EGAT	4	2	700	1990	construction
Japan	TEPCO–ACC	8	8	2,600	1995	construction
	Total ——>	131	71	13,764		2,555,035

Source:D.M. Todd, "GE Combined–Cycle Experience," General Electric Company, Schenectady, New York, 1989, updated until May 1990.

that the machine would be capable of producing if it were fully available during the same time period. When a plant is unavailable, it is said to have an "outage." There are two types of outages, planned outage and forced outage. A planned outage results from a decision of the plant operator to take the plant out of service for an inspection, regular overhaul, or other service. A forced outage results from a failure of equipment, causing a shutdown of the plant for repairs. Thus, percent unavailability is divided into two parts, the forced outage rate and the planned outage rate.

A recent study of combined-cycle plant and cogeneration reliability in the U.S. and Western Europe concludes that a well engineered, operated, and maintained plant could give greater than 90 percent equivalent availability.[3] Most plants in this study performed at between 80 percent and 92 percent availability, with some operating at 95 percent. Also, many baseload combined-cycle plants performed at greater than 90 percent availability, as did many baseload cogeneration plants. GE's own studies of combined-cycle reliability experience in plants of their design reported similar findings.[4]

Operation and Maintenance

Operation and maintenance cost is one of the most important variables to any plant owner. A well-designed and executed maintenance program can help provide low-cost, reliable service. Preventive maintenance procedures for combined-cycle plants range from simple procedures, such as intake air filter changes, to hot gas path inspections, to major inspections with the turbine case opened. Inspections represent the major maintenance that will be conducted during planned outages. Figure 2 shows the factors contributing to combined-cycle plant unavailability. Tables 2 and 3 show GE's recommended inspection intervals and estimated repair and replacement intervals for key equipment used in GE's combined-cycle plants. The replacement intervals give some basis for predicting forced outages.

While recognizing the constraints of international operations, gas turbine manufacturers such as GE emphasize the importance of operators achieving a full understanding of the equipment and all factors that affect the machine's performance. This awareness includes proper machine installation, accurate record keeping (especially failure analysis of forced outages), periodic inspections, adequate spares inventory, and training of staff. Table 4

[3] Bechtel, Inc. presentation at Joint Power Generation Conference New Orleans, Louisiana, 1989.

[4] Personal communication with John Romaniuk, op. cit.

shows operating inspection data parameters. These data represent a minimum that should be kept on logs.

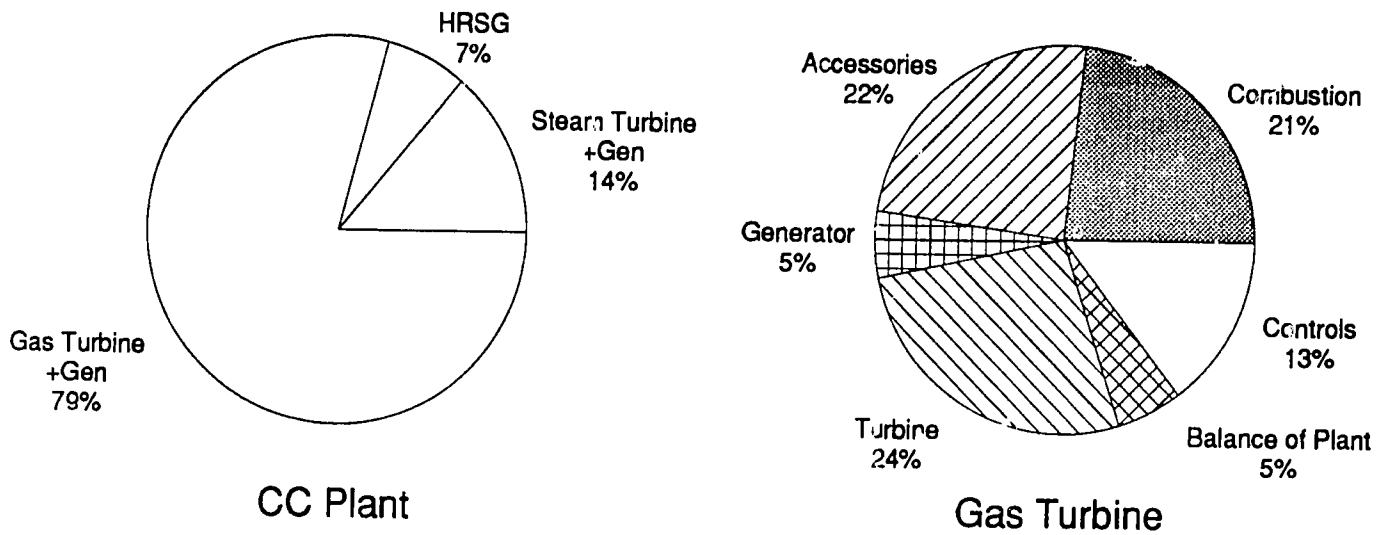


Figure 2. Factors Contributing to Combined-Cycle Plant Unavailability

Source: D.M. Todd, "GE Combined-Cycle Experience," General Electric Company, Schenectady, New York, 1989.

One factor affecting gas turbine life expectancy is the frequency of start-up and shut-down, because of the stresses imposed on the turbine blades by the heat-up/cool-down loading/unloading cycles. Thus, a machine with more frequent starts per fired-hour requires more maintenance and parts replacement than a baseload-rated turbine. This effect is indicated in Figure 3. Similarly, the effect of frequent starts and stops as a result of outages will result in a greater maintenance factor.

Gas turbines can be fired on natural gas, distillate petroleum, and in some cases, residual petroleum. In addition to the difference in cost per unit energy for each of these fuels, there is also a differential maintenance cost. Figure 4 displays the estimated effect of fuel type on maintenance. It can be seen from the figure that natural gas-fired units offer the lowest maintenance factors. Operation on residual fuel oil incurs very high maintenance costs which would be even higher in a typical developing country.

19

Table 2

Combined Cycle Planned Outages: Recommended Inspection Intervals for GE Plants

- CONTINUOUS-DUTY BASE FIRING TEMP.
- 1 START PER 1000 FIRED HOURS
- SPECIFICATION FUEL (GAS, DISTILLATE OR GAS/DISTILLATE)
- CURRENT PRODUCTION UNITS

INSPECTION TYPE	FUEL TYPE	FIRED HOURS					
		MS3002J	MS5002C	MS5001PA	MS6001B	MS7001EA/F	MS9001E/F
COMBUSTION	GAS	16,000	12,000	12,000*	8,000**	8,000**	8,000**
	DISTILLATE	16,000	12,000	12,000*	8,000**	8,000**	8,000**
HOT-GAS-PATH	GAS	24,000	ELIMINATED	ELIMINATED	24,000	24,000	24,000
	DISTILLATE	16,000	16,000	24,000	24,000	24,000	24,000
MAJOR	GAS	48,000	48,000	48,000	48,000	48,000	48,000
	DISTILLATE	32,000	32,000	48,000	48,000	48,000	48,000

*MS5001 TRANSITION PIECES CAN BE DEFERRED UNTIL 24,000 HOUR INSPECTION WITH THE EXCEPTION OF MS5001 LOW NO_x LINERS USING DISTILLATE FUEL. MAY ALSO BE IMPACTED BY AMOUNT OF WATER OR STEAM INJECTION FOR NO_x CONTROL OR POWER AUGMENTATION

**MAY BE IMPACTED BY AMOUNT OF WATER OR STEAM INJECTION FOR NO_x CONTROL OR POWER AUGMENTATION

Source: E.J. Walsh and M.A. Freeman, "Gas Turbine Operating and Maintenance Considerations," General Electric Company, Schenectady, New York, 1989.

Table 3

Predicting Combined Cycle Forced Outages: Estimated Repair and Replacement Cycles for GE Plants

- CONTINUOUS-DUTY BASE FIRING TEMPERATURE
- 1 START PER 1000 FIRED HOURS
- NATURAL GAS FUEL
- CURRENT PRODUCTION UNITS

	REPAIR* INTERVAL	REPLACE INTERVAL
COMBUSTION LINERS	8000**	40000
TRANSITION PIECES	12000**	48000
FUEL NOZZLES	8000**	24000
CROSS-FIRE TUBES	8000**	24000
1ST-STAGE NOZZLES	24000**	48000
2ND-STAGE NOZZLES	24000	48000
3RD-STAGE NOZZLES	24000	48000
1ST-STAGE BUCKETS	24000***	72000
2ND-STAGE BUCKETS	24000	72000
3RD-STAGE BUCKETS	24000	72000
FLOW DIVIDER (DISTILLATE)	8000	24000
FUEL PUMP (DISTILLATE)	8000	24000

* MAY BE IMPACTED BY AMOUNT OF WATER OR STEAM INJECTION FOR NO_x CONTROL OR POWER AUGMENTATION

** MS3002, 5001 AND 5002 UNITS WITH ADVANCE TECHNOLOGY COMPONENTS CAN HAVE LONGER REPAIR INTERVALS

*** BUCKET PROTECTIVE COATING IS STRIPPED AND RECOATED AT HOT-GAS-PATH INSPECTION

Source: E.J. Walsh and M.A. Freeman, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations," General Electric Company, Schenectady, New York, 1989.

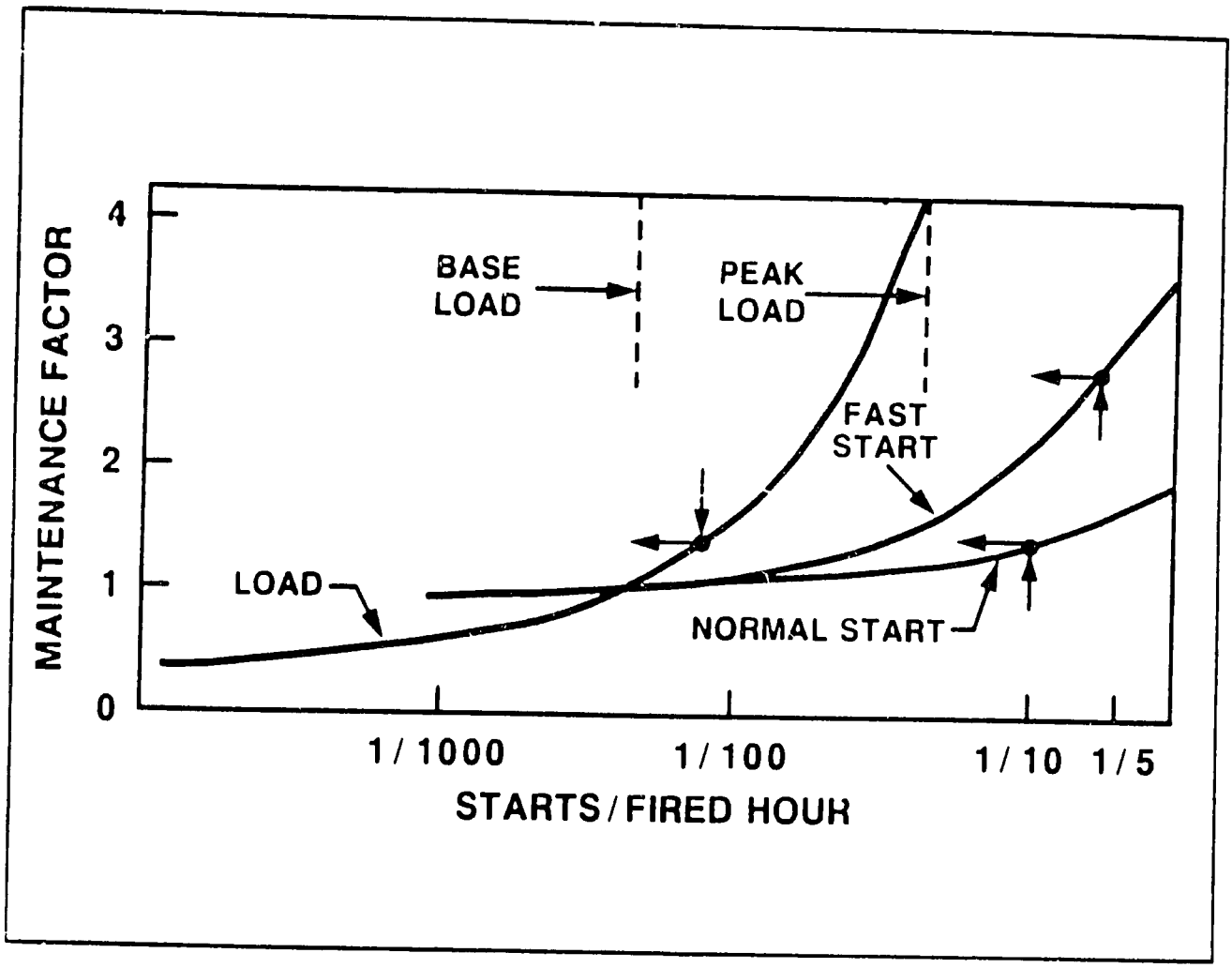


Figure 3. Estimated Effect of Load and Starts on Gas Turbine Maintenance

Note: Includes the effect of over-loading during peaking operation.

Source: E.J. Walsh and M.A. Freeman, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations," General Electric Company, Schenectady, New York, 1989.

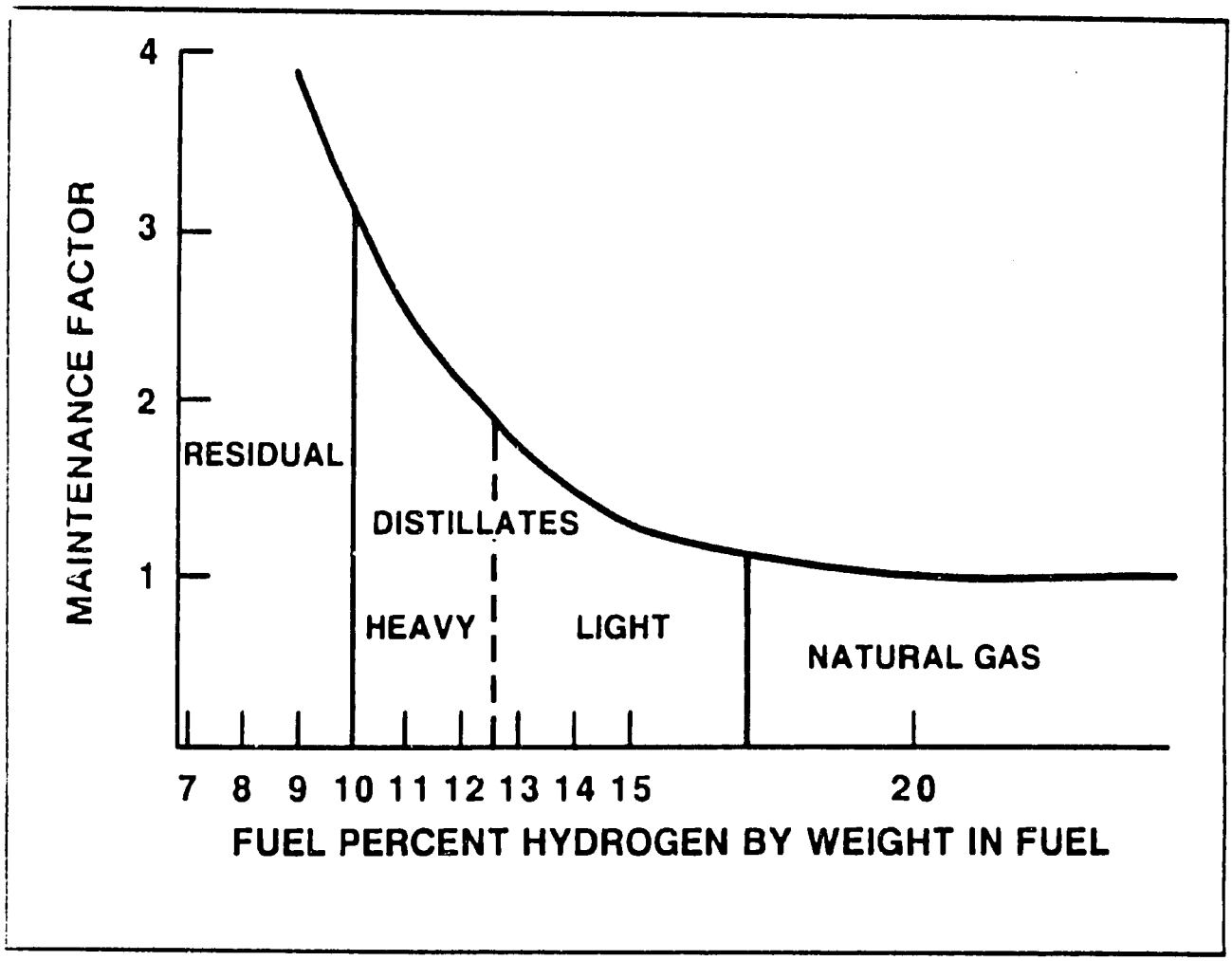


Figure 4. Estimated Effect of Fuel Type on Maintenance

Source: E.J. Walsh and M.A. Freeman, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations," General Electric Company, Schenectady, New York, 1989.

From Figures 3 and 4, we observe that today's heavy-duty gas turbines have an expected design availability of about 95 percent, based on an annual combustion system inspection, a hot-gas path inspection every four years, and a major inspection every seven years, adding in a forced outage rate of about 2-4 percent. This gives an upper limit baseline by which to judge actual performance.

Table 4

Gas Turbine Operating Inspection Data Parameters

▸ Speed	▸ Pressures
▸ Load	- Compressor Discharge
▸ Fired Starts	- Lube (Pumps)
▸ Fired Hours	- Bearing Header
▸ Site Barometric Reading	- Cooling Water
▸ Temperatures	- Fuel
- Inlet Ambient	- Filters (Fuel, Lube, Inlet Air)
- Compressor Discharge	▸ Vibration Data for Power Train
- Turbine Exhaust	▸ Generator
- Turbine Wheelspace	- Output Voltage - Field Voltage
- Lube Oil Header	- Phase Current - Field Current
- Lube Oil Tank	- VARS - Stator Temp.
- Bearing Drains	- Load - Vibration
- Exhaust Spread	▸ Start-Up Time
	▸ Coast-Down Time

Source: E.J. Walsh and M.A. Freeman, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations," General Electric Company, Schenectady, New York, 1989.

General Electric Company has compiled experience from all combined-cycle outages reported through its GE/User Weekly Load System for the Operational Reliability Analysis Program. This study concluded that about 79 percent of all outages can be attributed to gas turbine generator problems or maintenance, with 14 percent for the steam generator, and 7 percent for the heat recovery steam generator. Specific improvements that GE has made over the years to reduce the outage frequency include a new combustion system, turbine materials, redundant microprocessors, and sensors. Figure 5 displays GE's baseline design ("inherent") combined-cycle plant availability, based on inspection intervals and assumptions of a 2 percent or 4 percent forced outage factor.

14

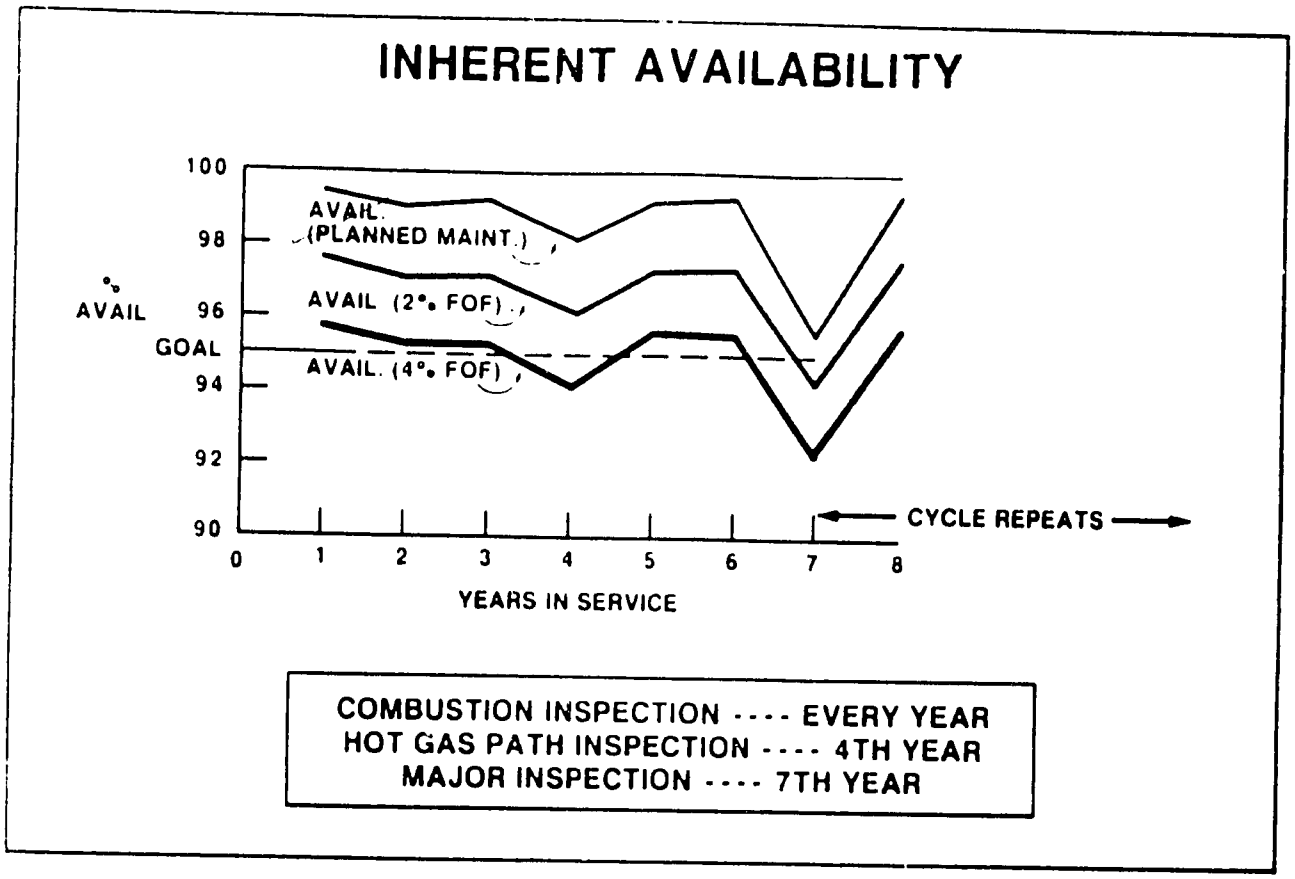


Figure 5. Inherent Availability

Source: D.M. Todd, "GE Combined-Cycle Experience," General Electric Company, Schenectady, New York, 1989.

2.4 SYSTEM ADVANTAGES AND DISADVANTAGES

Advantages

For most developing countries today, the baseload power generation system of choice is the coal-fired steam station. For oil-importing countries, such power stations represent an alternative to oil that is likely to be lower in cost per unit energy (joule, Btu, or kcal) and more stable in price over the lifetime of the plant. However, compared to oil, coal firing

25

adds additional cost for material handling, greater complexity in combustion operations, and increased environmental emissions. Many countries have natural gas that has not been fully developed. For these countries, combined-cycle technology offers a number of advantages, compared to traditional steam power stations, which are fired by coal or oil:

- Lower capital cost per megawatt of capacity. In 1990, U.S. dollars, the cost of combined-cycle technology is about $600 per kilowatt, whereas, competing coal technologies cost $1,200 per kilowatt or more.

- Shorter installation time. Compared to the 48-60 month construction time for a coal-fired plant, a typical pre-engineered combined-cycle plant takes approximately 30 months to build and commission, from the date of order. Plants of the multi-shaft type, which can be built in phases to allow gas turbine or simple-cycle power production prior to combined-cycle commissioning, can be built and commissioned in about 18 months. Further, environmental siting requirements for a gas-fired plant are much easier than for a coal-fired station, a factor that is growing in importance worldwide. Figure 6 depicts the project schedule for a typical two-phase, multi-shaft, combined-cycle installation.

  The relatively short construction and installation schedule of combined-cycle plants enhances their economics. The cost components where savings are realized include:

  - factory packaging of all components
  - modular construction, which saves on detailed plant engineering costs
  - low direct construction costs
  - short installation times, which reduce interest payments
  - auxiliary systems are packaged as separate units.

- Higher thermal efficiency. Efficiency levels for gas-fired combined-cycle plants have been growing steadily over the past few decades, and are currently nearly 50 percent (compared to 40 percent for 1,000 MW coal-fired plants with reheat and regeneration cycles). GE expects the efficiency of its combined-cycle (gas-fired) plants to reach 55 percent by the late 1990s. Figure 7 depicts the increase in efficiency achieved by GE with their combined-cycle plants. The efficiency is reported using the lower heating value (LHV) of natural gas. This convention has been followed for the case study as well.

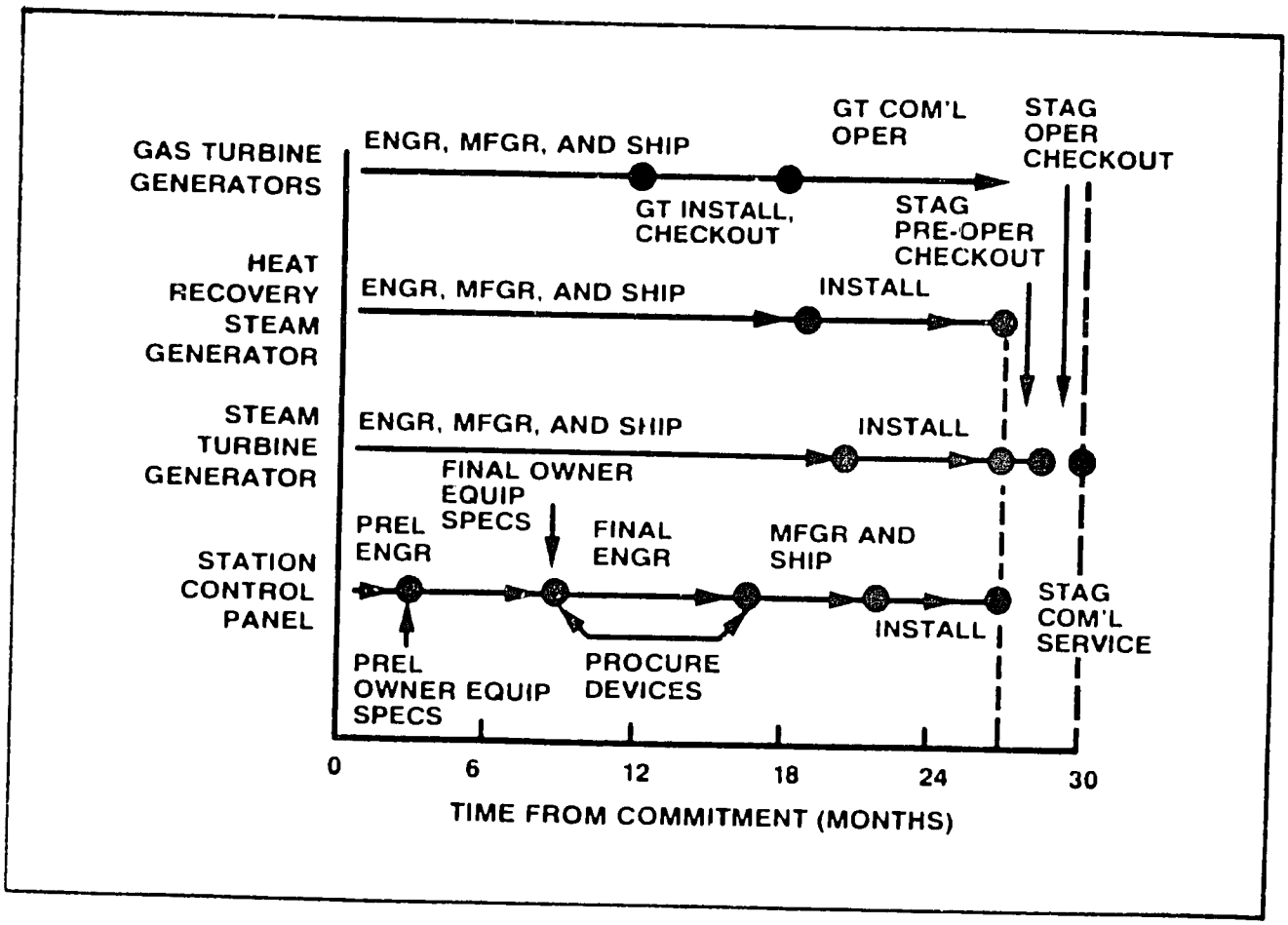


Figure 6. Typical Project Schedule

Source: D.L. Chase, L.. Tomlinson, and R.W. Bjorge, "GE Combined-Cycle Product Lives and Performance," General Electric Company, Schenectady, New York, 1989.

- Environmental benefits. Because they are fired with natural gas, a fuel with little or no sulfur content, combined-cycle units show lower emissions of sulfur dioxide, the primary gas that contributes to acid rain. Because natural gas has a much higher hydrogen-to-carbon ratio than coal, and because of the higher efficiency of combined-cycle units, emissions of CO_2, the primary greenhouse gas contributing to global climate change, are cut in half. A gas-fired combined-cycle plant will have about 25 percent lower

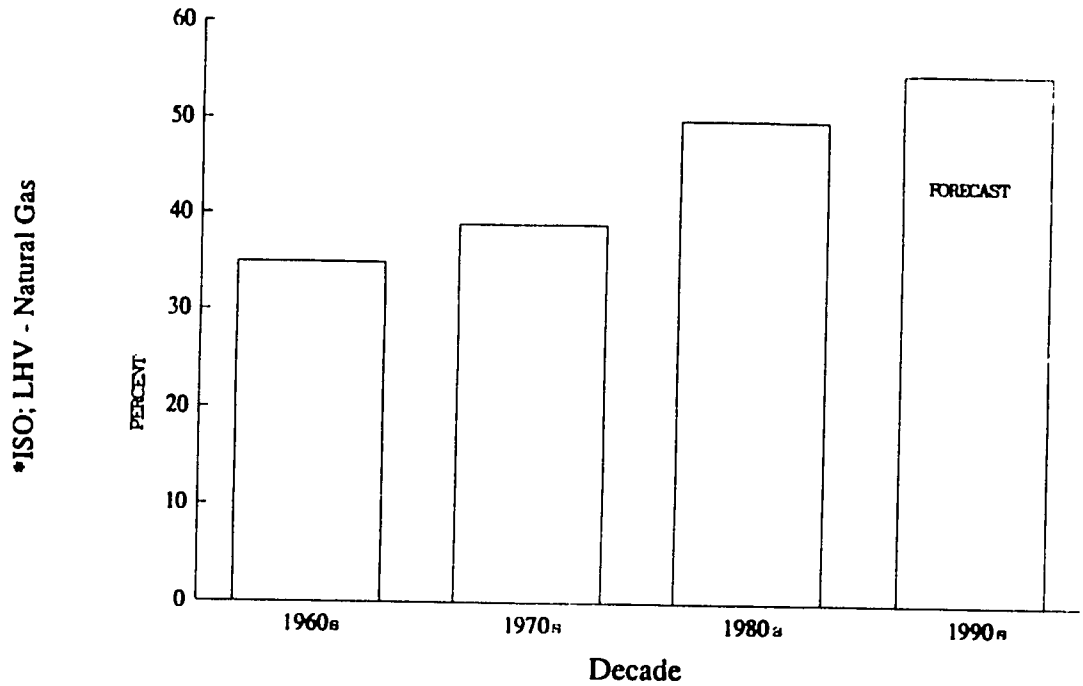


Figure 7. Growth of STAG Combined-Cycle Power Plant Efficiency

Source: Douglas M. Todd, "GE Combined-Cycle Experience," General Electric Company, Schenectady, New York, 1989.

CO_2 emissions than a gas-fired steam plant, because of the higher efficiency.

- Modular technology. Of particular importance to developing countries, gas turbine-based systems offer a modularity, which permits capacity additions to be made quickly, in line with demand growth.

Disadvantages

The primary disadvantage of the combined-cycle plant is its use of gas turbines, which require the use of fuels that are clean, and often more costly than the fuels used by traditional baseload utilities (coal and residual oil). The economic cost of distillate petroleum is 50 to 80 percent more than residual oil, and in some countries, natural gas is not available or has a high economic cost.

28

However, this feature is not a disadvantage for countries that are oil producers. Often, such nations have abundant supplies of natural gas or associated gas that is now being flared at oil production facilities. In these cases, combined-cycle technology is at an advantage because it can employ this low-cost fuel source.

Electric power generation represents one of the best ways to begin the exploitation of indigenous gas resources in a developing country. Investment in gas exploration, pipelines, compressors, and distribution facilities requires substantial capital. Because of the uncertainty of demand for gas, these investments are inherently risky. What is generally needed is a large baseload user of the gas in order to make the project economic. In many cases, the fertilizer or other chemicals industry has provided this pull, but the uncertainty of and competition in today's markets for petrochemicals has reduced this option. However, in nearly all developing countries, the demand for power is growing at a prodigious rate. Thus, the opportunity exists to provide the baseload pull needed for gas development by generating power for higher value added through the electric grid. This electric power can then be used to promote economic development by a wide variety of industries.

Another disadvantage of combined-cycle technology, especially for developing countries is the lack of available trained staff and equipment to operate and maintain the system, which is somewhat more complex than the traditional simple-cycle gas turbine system. Thus the potential maintenance cost of combined-cycle technology may be higher than expected, particularly if inadequate operations leads to premature failure and reduced life expectancy. In fact, however, combined-cycle plants are less complex than standard solid-fuel steam plants equipped with environmental safeguards in terms of spare parts inventory, instrumentation, and controls.

CHAPTER 3: GUDDU POWER PLANT, PAKISTAN

The primary plant in the A.I.D. Office of Energy's study of combined-cycle experience is the 600 MW Guddu Combined Cycle Power Station in Pakistan. This plant was selected as the primary plant for study because it has the longest history of operation of any combined-cycle plant in any A.I.D.-assisted developing country.

The Guddu power plant is owned and operated by the Water and Power Development Authority (WAPDA) of the Government of Pakistan. WAPDA is an autonomous government-owned statutory body, licensed under the Electricity Act of 1919. It is responsible for the generation, transmission, and distribution of all electricity in the country, outside of the metropolitan Karachi area.

The 600 MW combined-cycle Guddu power plant is located in the district of Guddu (Kashmore, Baluchistan province), approximately 600 km from Karachi (see Figure 8). The plant is situated at an elevation of 80.16 meters above sea level.

The Guddu plant was commissioned and constructed for a total cost of U.S. $296 million (1982 dollars). Of this, the foreign exchange component ($193 million) was financed by an Asian Development Bank loan of $140.9 million and an A.I.D. loan of $52.1 million. The local currency requirements (an equivalent of U.S. $103 million) were financed by the Government of Pakistan.

The power plant rating is listed by WAPDA as 450 MW, in recognition of a planned availability and load factor over the course of time. However, for the purposes of this report, we indicate the plant as 600 MW, which is the nameplate capacity and is the size that the manufacturer, General Electric (GE), uses in its description of the plant.

3.1 CONSTRUCTION HISTORY

WAPDA is experiencing a rapid increase in peak demand (about 6 percent per year) and a severe capacity shortage, which requires frequent load shedding. Pakistan's generation-consumption gap has been forecast to cross the 5,000 MW mark in 1990, and so the government is implementing a program to boost electricity production and distribution with the assistance of international donor agencies. At the same time, Pakistan is an oil-importing country with significant gas resources that are not being fully exploited. It is in

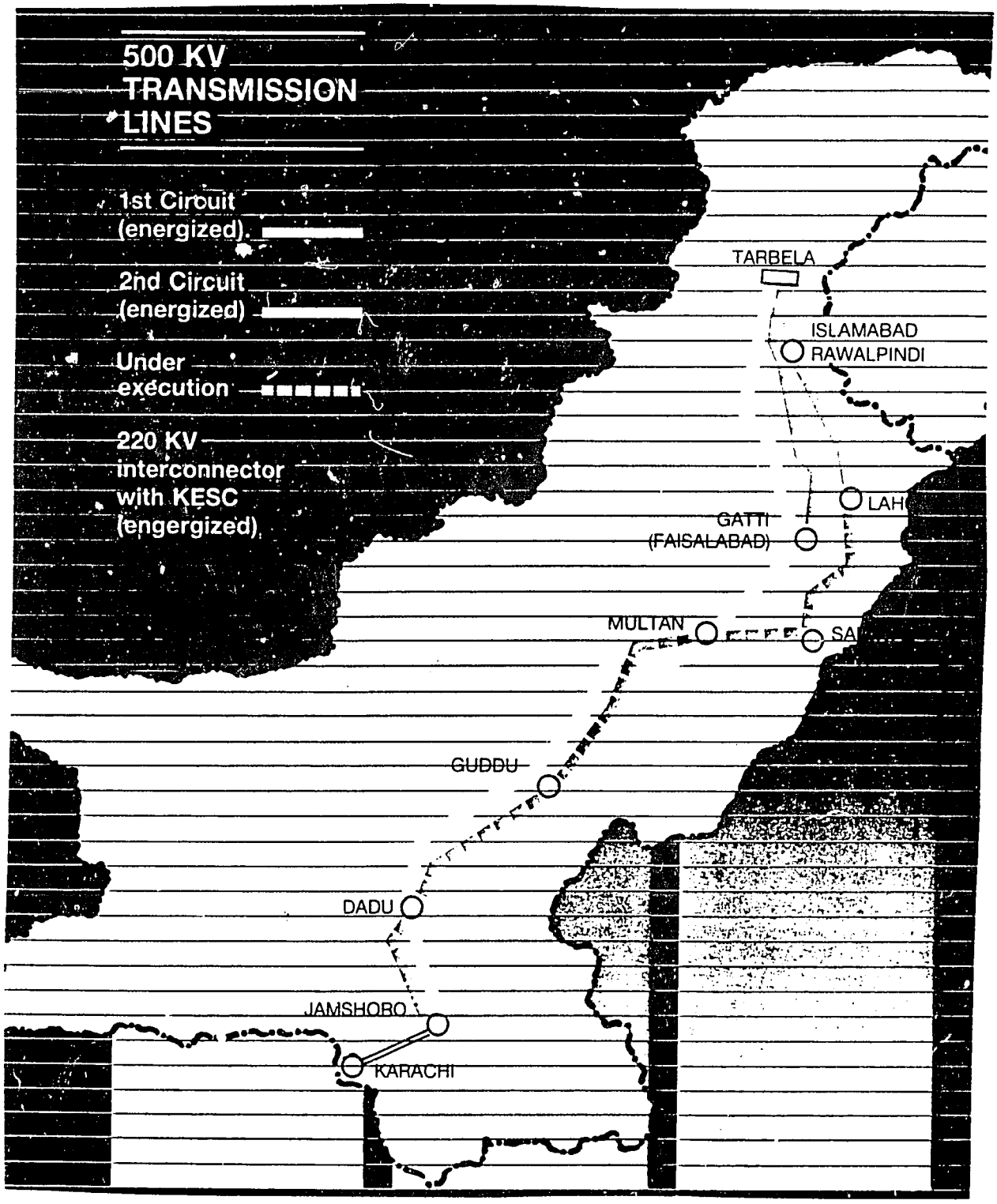


Figure 8. Location of Guddu Power Plant

Source: Water and Power Development Authority of Pakistan, 1989 Annual Report.

31

the context of this situation that a decision was made to install a gas-fired combined-cycle power plant at a central location, Guddu, where WAPDA already had four small thermal units.

Construction of the Guddu plant was originally scheduled to begin in July 1982 and conclude in February 1988. Minor delays were encountered along the way in the loan approval process, construction was delayed by one year, and the project was completed in November 1988. This delay further postponed the recruitment of the power plant's local consulting engineers, NESPAK Limited, who were awarded a contract in November 1983. The chart below displays a history of the Guddu plant's commissioning.

Plant Commissioning		
Equipment	Unit	Date
Construction Started		July 1983
Gas Turbine Generator	G-7	December 1985
Gas Turbine Generator	G-9	March 1986
Gas Turbine Generator	G-8	April 1986
Gas Turbine Generator	G-10	April 1986
Steam Turbine Generator	G-5	January 1988
Steam Turbine Generator	G-6	March 1988

Source: Information obtained from WAPDA, Pakistan.

Following a competitive bidding procedure, General Electric Company (GE) of Schenectady, New York was awarded a contract for supplying key equipment for power plant erection and commissioning. Since commissioning, GE staff have continued to provide support at the plant, participating in inspections, overseeing major maintenance, troubleshooting, and training local staff in several aspects of plant operation.

The firm of Gibbs and Hill, Inc. was retained by USAID to provide expatriate consultants to the project. The firm also provided the conceptual design and all bid specifications for equipment, including gas turbines, HRSG, and gas pipelines. Gibbs and Hill staff evaluated bids, prepared contracts, and implemented individual contracts, and the firm provided field supervision and monitoring services as well.

Guddu's civil works and plant construction details were performed by a group of five local firms. They are Habib Rafique Limited, Imperial Construction Company Limited, MLC Limited, Compaigner Associates, and KSEW Limited.

3.2 PLANT DESIGN

The Guddu combined-cycle power plant has a total design capacity of 600 MW. The plant's physical configuration consists of four gas turbines, four heat recovery steam generators (HRSGs), and two steam turbine generators. GE's plant designation for this site is **STAG-209E** (times two). The **STAG** represents a steam and gas plant, the **2** the number of gas turbines, the **9** the model series gas turbine frame, and the **E** the model gas turbine. A site plan for the Guddu plant is shown in Figure 9. Figure 10 shows a typical STAG plant configuration for a similar GE combined-cycle plant.

The GE gas turbine and HRSG are designed to be operated as baseload units. In baseload operation, the steady inlet temperature profile minimizes thermal shocks to turbine blade materials. The plant also has a provision for operation as a peaking unit, but this option has seldom been exercised due to continuous demand for power in the WAPDA system. GE indicates that use of the system for peaking may results in excessive materials breakdown (fuel nozzles, combustion liners, transition pieces, cross-fire tubes, and turbine blades) in the hot-gas path and associated high maintenance costs.

Gas Turbines and Generator Set

The plant's four gas turbines are rated at a design capacity of 110 MW each at 50 degrees Fahrenheit. The turbines are GE's heavy-duty model PG 9151E, Frame 9 type. The designation "E" indicates that the units are modified to operate at a higher firing temperature, of about 1,985 degrees Fahrenheit, and a greater mass flow rate than the U.S. model. The turbines are equipped with integral electric motors for remote starting and synchronizing features in addition to local auto-starting. They also include an auto-clean compressor intake air filter system with 1,280 elements. These turbines have the following features:

- fuel: natural gas or distillate (high-speed diesel)
- rated net output: 110 MW
- turbine heat rate: 11,950 to 12,350 KJ/kWh or 12,605 to 13,027 Btu/kWh
- turbine speed: 3,000 rpm
- turbine exhaust temperature: 549-578 degrees Centigrade

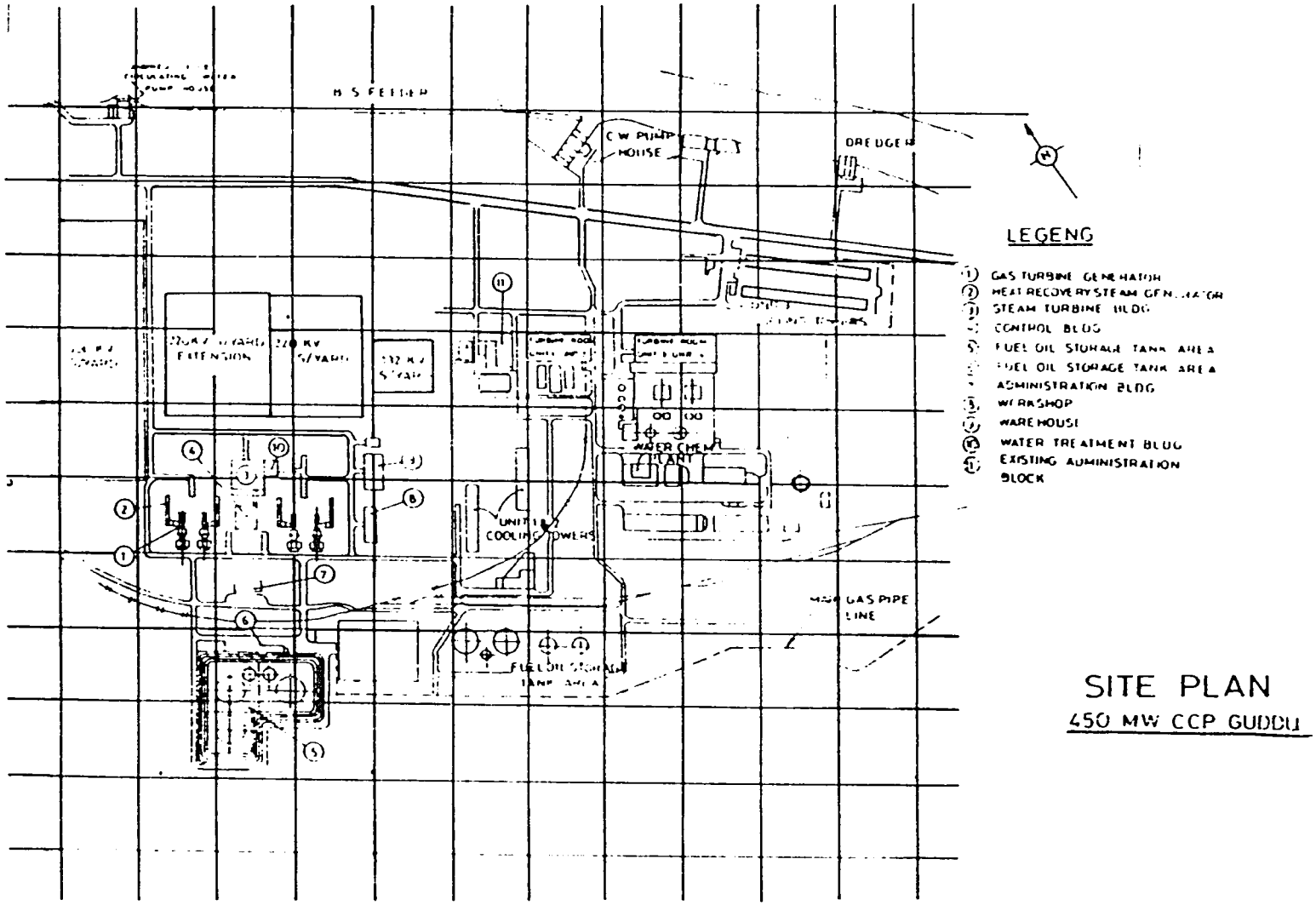


Figure 9. Guddu Site Plan

Source: Water and Power Development Authority of Pakistan (WAPDA).

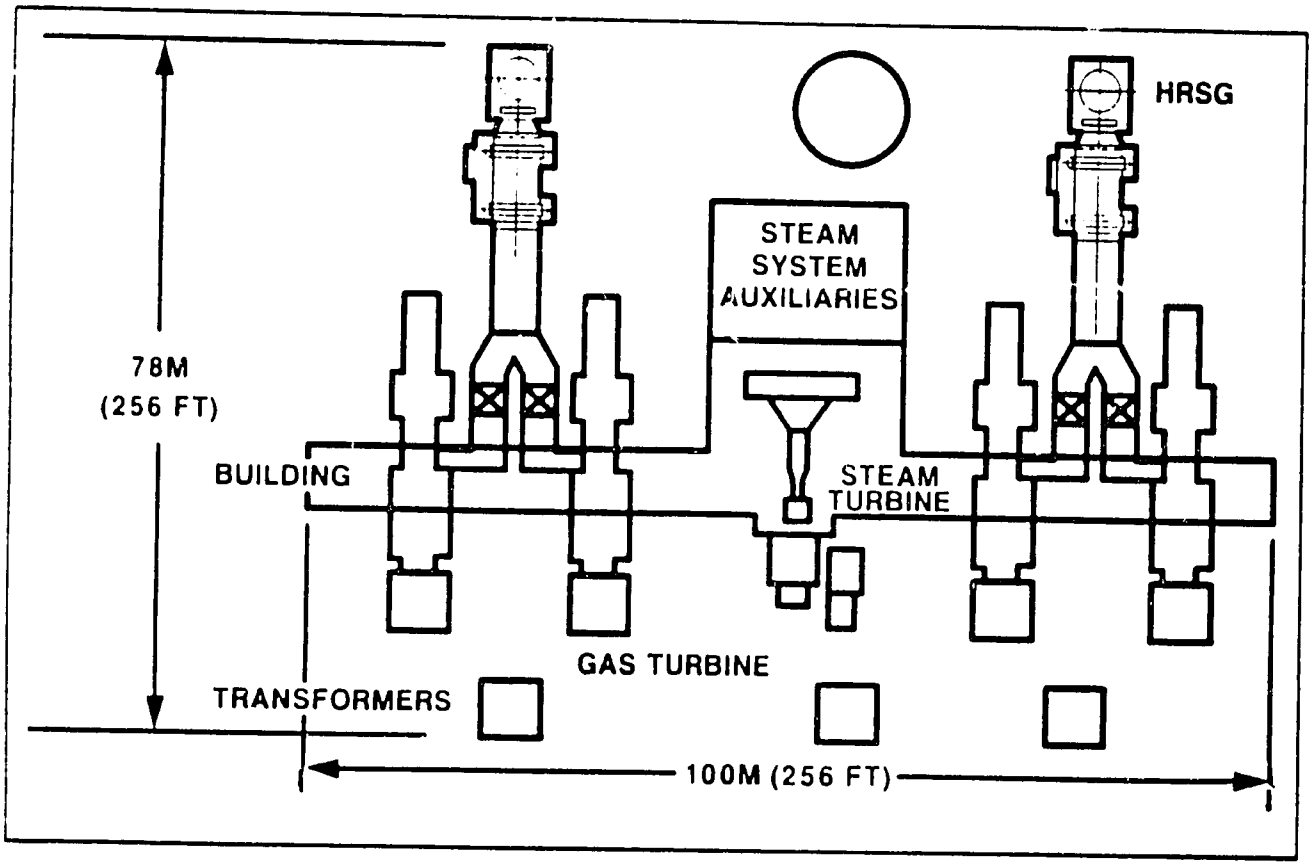


Figure 10. Typical STAG GE Combined-Cycle Plant Configuration

Source: D.L. Chase, L.O. Thomlinson, and R.W. Bjorge, "General Electric Combined Cycle Product Line and Performance," General Electric Company, Schenectady, New York, 1989.

- 17 compressor stages, 3 turbine stages
- compression ratio: 11.5:1.

The combined cycle was not the first plant installed at Guddu, and the notation used by WAPDA, and therefore followed in this report, to designate the four gas turbines is G-7, G-8, G-9, and G-10. The steam turbines are designated G-5 and G-6.

Each gas turbine is connected to a 2-pole, hydrogen-cooled synchronous generator assembly, synchronized to the WAPDA transmission grid. Its specifications are as follows:

- rating: 125.880 MVA at 0.85 power factor and 128.890 MVA at a 0.90 power factor
- rated voltage: 11.5 kV
- frequency: 50 Hz
- rotor speed: 3,000 rpm.

Heat Recovery Steam Generators

The four GE Heat Recovery Steam Generator (HRSG) units are unfired waste-heat boilers that function only when the gas turbine is operating in the combined-cycle mode. Each HRSG includes a steam drum and separate sections for evaporator, superheater, and economizer. Each HRSG operates with forced circulation via a horizontal, radially split, single-stage, centrifugal circulating pump. The HRSG output is controlled via a modulating damper, which directs exhaust flow either into the HRSG or to the gas turbine bypass stack.

- Number of units: four
- HRSG performance with a baseload turbine:

Inlet air temperature	30° F	80.4° F	104° F	122° F
Maximum steam flow (lbs/hr)	6,302	5,982	5,898	5,717
Steam pressure at superheater outlet (psig)	936	942	930	909
Steam temperature at superheater outlet (° F)	936	965	977	991
Feedwater temperature at economizer outlet (° F)	167	171	172	172

HRSG exit gas (° F)	361	361	360	356
HRSG design maximum pressure (psig)	1,166			

The two GE model DF-23 steam turbine generators are fully-enclosed units with hydrogen-cooled synchronous generators. The hydrogen coolers are vertically mounted in the cooling towers located at the four corners of the frame.

Generator Data

- kilovolt amperes: 118,306 rating
- armature amperes: 5,939 rating
- field amperes: 11,500 rating
- exciter volts: 500 rating
- power factor: 0.85
- no load field current amperes: 348

Control and Information System

The gas turbine generator is equipped with a microprocessor-based GE SpeedTronic II ITS control system (the Mark II ITS). This system is designed to control speed, fuel, temperature, vibration, flame, fire, oil pressure, generator output, inlet guide vanes, and water and steam injection under various operating conditions. The operator interface consists of a screen providing real-time plant information to the operator, who responds via an industrial-grade membrane keypad (see Figure 11).

Each of the four gas turbines is equipped with a dedicated log printer that is capable of printing critical operating conditions backward in time on a logarithmic time scale. The control panel provides the operator with continuous turbine diagnostic information. In particular, the integrated temperature system (ITS) option on the control panel offers continuous data on temperature, pressure, and vibration of the turbine, compressor, and generator set.

The Mark II control system features include:

- redundant control sensors and control system
- two independent means of turbine shutdown
- double failure may cause a shutdown (but always a safe shutdown)

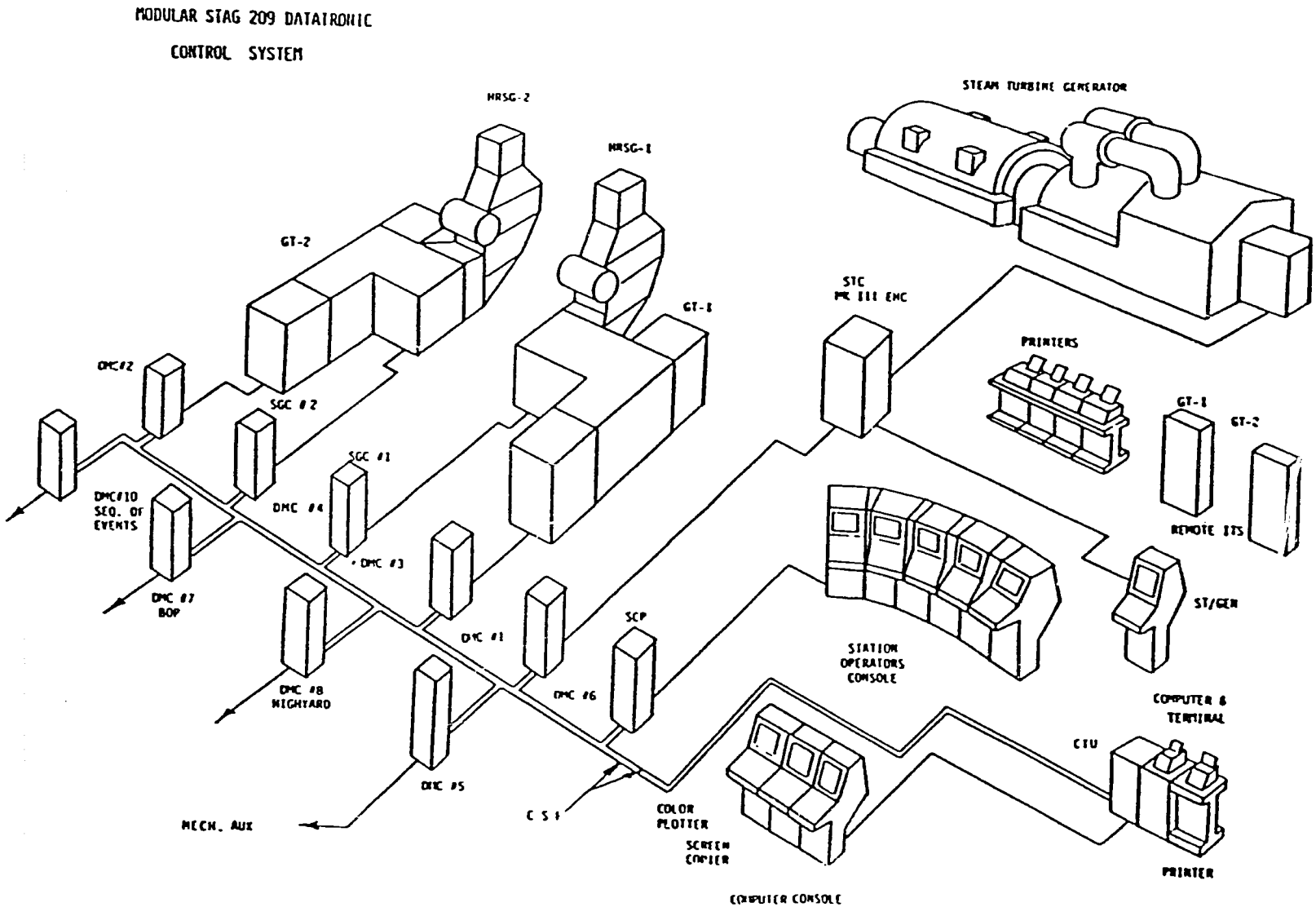


Figure 11. Distributed Control and Information System

Source: Water and Power Development Authority of Pakistan (WAPDA).

- generator drive turbines should tolerate full load rejection without overspeeding
- alarms sound before a trip.

Water Cooling System

The water cooling system for the Guddu plant is a pressurized system designed to use water from the Indus River at 27 degrees Centigrade.

Fuel

The fuel designated for the Guddu power station is natural gas from the Mari, Kandhkot, and Sui fields. Natural gas from these fields is mixed at a gas mixing station prior to being piped into the plant. High-speed diesel (HSD) is stored for emergency use only. The characteristics of the natural gas being used at the Guddu plant are shown below. The typical lower heating value (LHV) of mixed gas is about 833 Btu/cu-ft.

Natural Gas Quality	Mari	Kandhkot	Sui
Methane (% vol.)	71.2	88.52	79.2
Ethane (% vol.)	0.2	0.89	1.1
Propane (% vol.)	--	0.26	1.1
Butane and Higher (% vol.)	--	0.37	0.4
Nitrogen (% vol.)	19.5	2.46	16.6
Carbon Dioxide (% vol.)	9.0	7.35	2.5
Hydrogen Sulphide (g/100 cu-ft)	0.1	92.20	30.8
Mercaptan Sulphide (g/100 cu-ft)	--	3.80	1.2
Lower Heating Value (LHV, Btu/cu-ft)	724.2	934	843

3.3 PLANT OPERATIONS

Plant Staffing

The Guddu combined-cycle power station has a total staff of 364, headed by a WAPDA resident engineer. Two assistant resident engineers are responsible for plant operation and maintenance, respectively. The station is staffed by 45 engineers, one junior chemist, and 28

plant technicians. In addition, there are 185 maintenance staff and 112 operators and attendants. WAPDA operates a continuing education training academy for the benefit of Guddu plant engineers and technicians.

Generation and Capacity Factor

Monthly generation statistics for the gas turbines and steam turbine generators and for availability are shown in Table 5 for the period January 1988 to February 1990. For the period January through August 1988, the Guddu plant was operating as a simple-cycle station with the gas turbine generator displaying an availability averaging 86 percent. The combined-cycle mode was achieved in September, with the station availability dropping to 72 percent. This reduction is due to gas turbine outages relating to bypass damper adjustments and electronic control system problems. Also, the synchronous condenser was being tested at the same time. The forced and planned outages on the gas turbine, which result in lower availability, are reflected in the output of the steam turbine generator.

For the 1989 period, gas turbine generator G-7 was out of commission for almost the whole of February and March. This major vibration- and system-related forced outage, coupled with combustion system forced outages, resulted in the 40 percent to 50 percent range of availability that is seen in Table 5.

The capacity factor is the ratio of the energy generated by the unit during some time period to the energy that could have been generated had the unit run at its full rating over the same period. Capacity factor is used as a power plant performance indicator and is tabulated for the Guddu plant in Table 6. The capacity factors for the Guddu power station range from a low of 38.8 percent to a high of 91.4 percent. The reason may be seen in the lower diagram in Figure 12. During the month of November 1989, steam turbine generator G-6 was unavailable due to a fire at turbine bearing No. 1 on machine G-5 and an inspection that lasted close to 22 days.

Heat Rate and Efficiency

Heat rate is defined as specific fuel consumption, as measured in units of fuel energy per kilowatt-hour of electrical energy generated. In this report, heat rate is reported on the basis of Lower Heat Value (LHV) of the fuel. Gross heat rate is measured at the generator, net heat rate subtracts the energy used in the power station (for circulating pumps, water treatment, generator excitation, lighting, and other uses). Heat rate is inversely proportional to

Table 5. Guddu Plant: Availability, Generation, and Station Heat Rates

Date	GTG avail-ability	gener-ation (MWh)	STG avail-ability	gener-ation (MWh)	Station avail-ability	Net station heat rate (Btu/KWh)
Jan-88	93%	264,994	na	42,147	na	10,449
Feb-88	90%	226,268	na	34,010	na	10,246
Mar-88	75%	219,710	na	40,016	na	9,775
Apr-88	77%	209,946	na	54,208	na	9,526
May-88	90%	249,798	na	94,908	na	8,695
Jun-88	94%	250,531	na	70,798	na	9,261
Jul-88	88%	242,672	na	81,647	na	8,869
Aug-88	81%	212,964	na	82,169	na	na
Sep-88	72%	192,489	71%	74,006	72%	9,007
Oct-88	53%	143,874	75%	51,564	59%	9,215
Nov-88	48%	138,502	56%	57,881	50%	8,704
Dec-88	66%	188,912	92%	79,178	74%	8,640
Jan-89	72%	220,756	99%	93,196	80%	8,320
Feb-89	50%	130,017	98%	57,350	64%	8,380
Mar-89	40%	124,425	80%	48,920	52%	8,798
Apr-89	68%	189,910	95%	89,682	76%	8,179
May-89	74%	204,416	94%	97,189	80%	8,176
Jun-89	75%	196,877	96%	97,634	81%	8,180
Jul-89	90%	243,911	99%	92,586	93%	8,592
Aug-89	99%	273,248	60%	53,035	88%	10,282
Sep-89	91%	237,930	49%	47,307	78%	9,754
Oct-89	77%	219,818	43%	33,868	67%	12,622
Nov-89	81%	184,664	21%	14,832	63%	11,166
Dec-89	95%	263,136	79%	81,812	90%	9,030
Jan-90	98%	293,835	99%	129,100	98%	8,401
Feb-90	94%	250,648	99%	112,331	95%	8,160
Summary Statistics						
avg. 1988	60%	211,722	73%	63,544	64%	8,892
avg. 1989	76%	207,426	76%	67,284	76%	9,290
avg. 1990*	96%	272,242	99%	120,716	97%	8,281
avg. 26 mth	78%	214,394	78%	69,668	76%	8,863

Note: GTG = gas turbine generator, STG = steam turbine generator

* data and averages for the year 1990 reflect January and February only

averages for the year 1988 reflect September thru December data only

na = not available

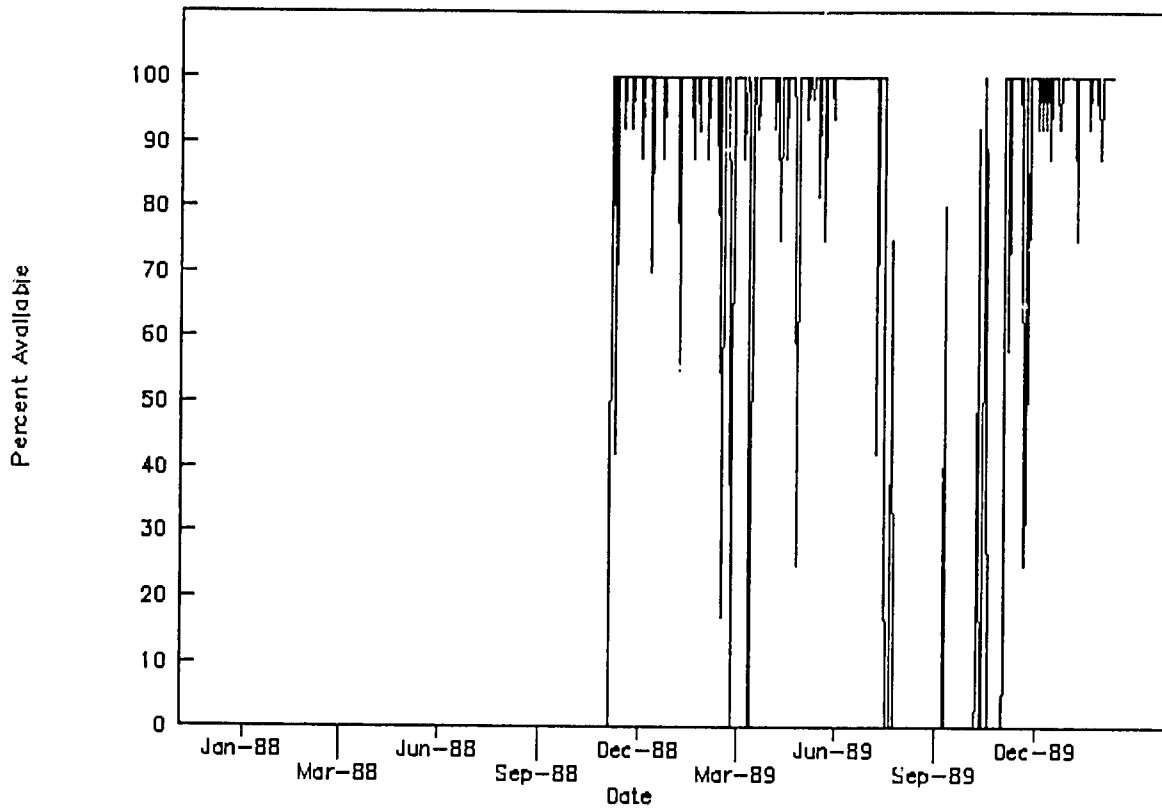
Source: Derived from WAPDA (Pakistan) data, April 1990.

Table 6. Guddu Plant: Capacity and Utilization Factor

Date	GTG generation (MWh)	STG generation (MWh)	Total generation (MWh)	GTG Capacity factor	STG Capacity factor	Plant Capacity Factor	Plant Utilization Factor
Jan-88	264,994	42,147	307,141	83.2%	58.5%	78.6%	na
Feb-88	226,268	34,010	260,278	77.5%	50.5%	72.4%	na
Mar-88	219,710	40,016	259,726	72.6%	55.5%	69.3%	na
Apr-88	209,946	54,208	264,154	73.2%	38.9%	62.0%	na
May-88	249,798	94,908	344,706	84.0%	65.9%	78.1%	na
Jun-88	250,531	70,798	321,329	88.3%	50.3%	76.0%	na
Jul-88	242,672	81,647	324,319	81.9%	56.7%	73.7%	na
Aug-88	212,964	82,169	295,133	71.9%	57.0%	67.0%	na
Sep-88	192,489	74,006	266,495	67.4%	53.1%	62.7%	87.6%
Oct-88	143,874	51,564	195,438	48.9%	35.8%	44.6%	75.4%
Nov-88	138,502	57,881	196,383	47.6%	41.5%	45.6%	90.8%
Dec-88	188,912	79,178	268,090	60.0%	55.0%	58.4%	79.4%
Jan-89	220,756	93,196	313,952	69.3%	64.7%	67.9%	84.7%
Feb-89	130,017	57,350	187,367	44.5%	42.5%	43.9%	68.5%
Mar-89	124,425	48,920	173,345	41.1%	34.0%	38.8%	74.9%
Apr-89	189,910	89,682	279,592	66.2%	64.3%	65.6%	86.6%
May-89	204,416	97,189	301,605	68.8%	67.5%	68.3%	85.8%
Jun-89	196,877	97,634	294,511	69.4%	70.0%	69.6%	85.8%
Jul-89	243,911	92,586	336,497	82.3%	64.3%	76.4%	82.2%
Aug-89	273,248	53,035	326,283	92.2%	36.8%	74.1%	84.5%
Sep-89	237,930	47,307	285,237	83.3%	33.9%	67.1%	85.6%
Oct-89	219,818	33,868	253,686	74.7%	23.5%	57.9%	86.1%
Nov-89	184,664	14,832	199,496	63.4%	10.6%	46.3%	73.5%
Dec-89	263,136	81,812	344,948	83.5%	56.8%	75.1%	83.2%
Jan-90	293,835	129,100	422,935	92.2%	89.6%	91.4%	92.9%
Feb-90	250,648	112,331	362,979	88.9%	86.3%	88.1%	92.5%
Summary Statistics							
avg. 1988	165,944	65,657	231,602	71.4%	51.6%	65.7%	83.3%
avg. 1989	207,426	67,284	243,466	69.9%	47.4%	62.6%	81.8%
avg. 1990*	272,242	120,716	241,448	90.6%	88.0%	89.7%	92.7%
avg.26 mth	214,394	69,668	235,689	72.2%	52.5%	66.1%	57.7%

Note: GTG = gas turbine generator, STG = steam turbine generator
* data and averages for the year 1990 reflect January and February only
averages for the year 1988 reflect September thru December data only
na = availability data not provided
Source: Derived from WAPDA (Pakistan) data, April 1990.

Availability of Steam Turbine Generator, G-5



Availability of Steam Turbine Generator, G-6

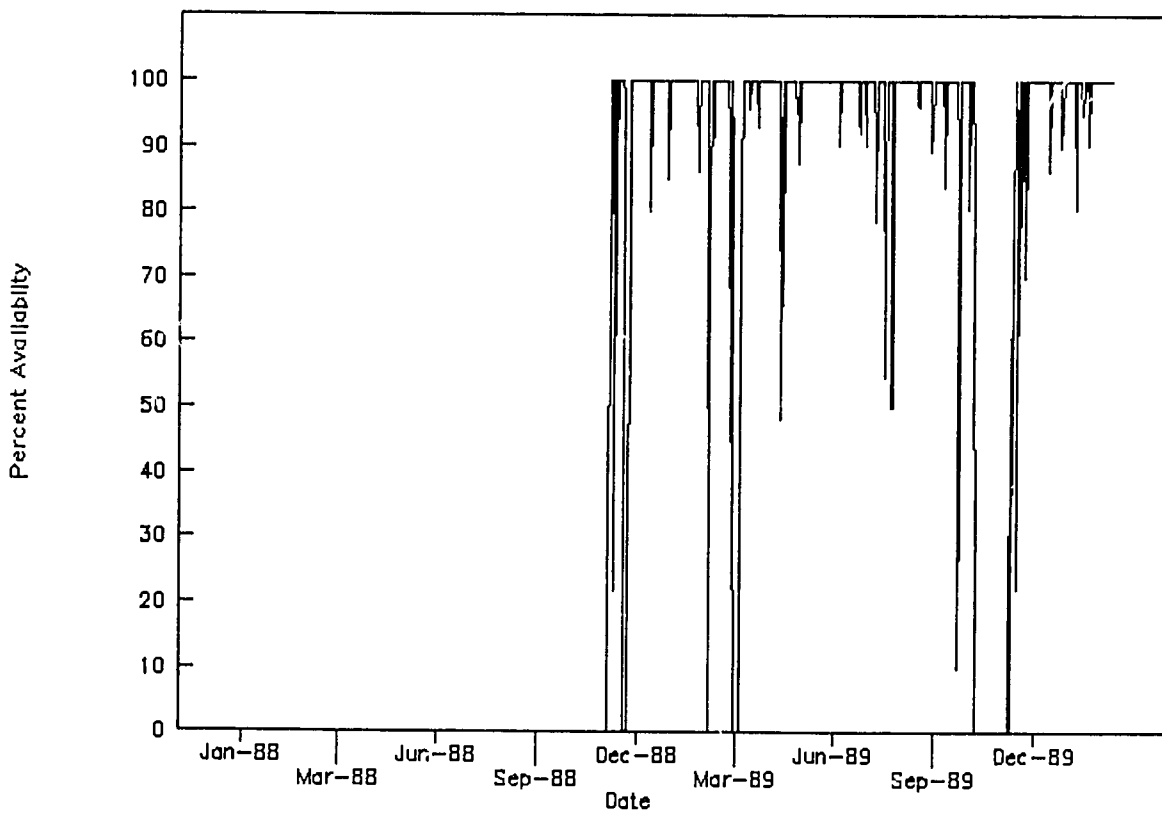
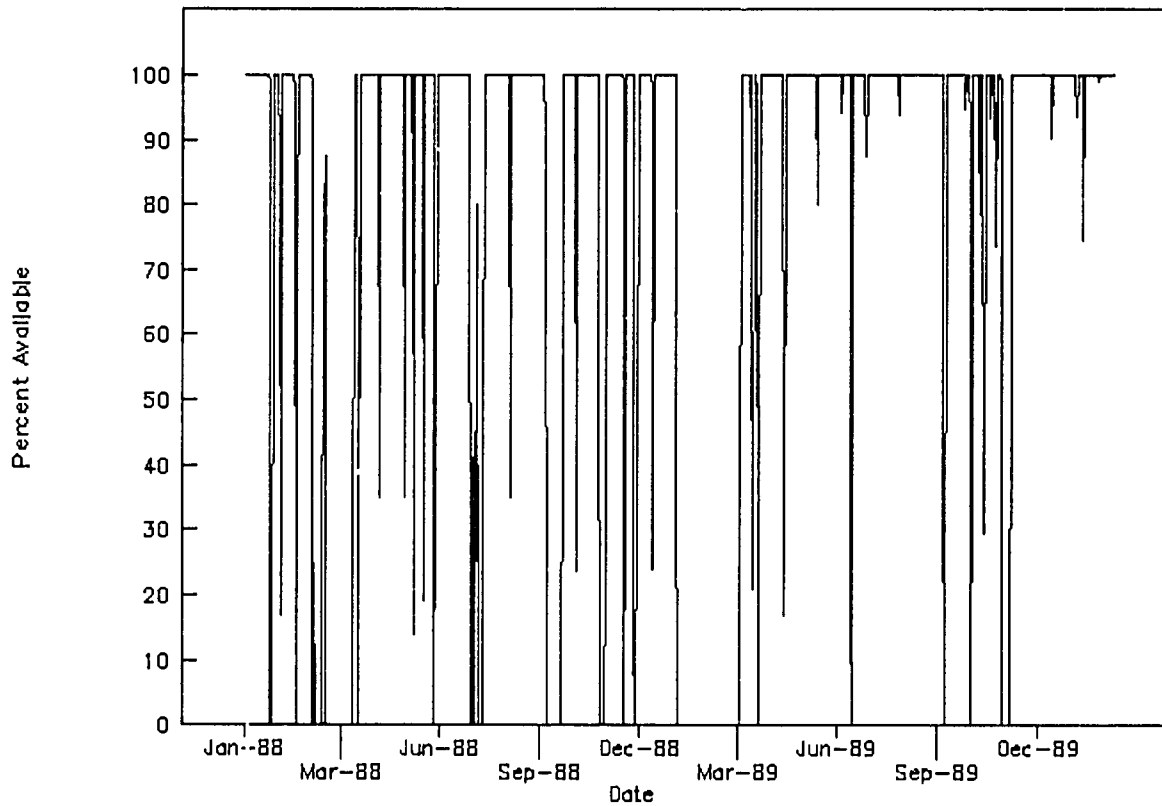


Figure 12. Guddu Plant Generator and Station Availabilities

Availability of Gas Turbine Generator, G-7



Availability of Gas Turbine Generator, G-8

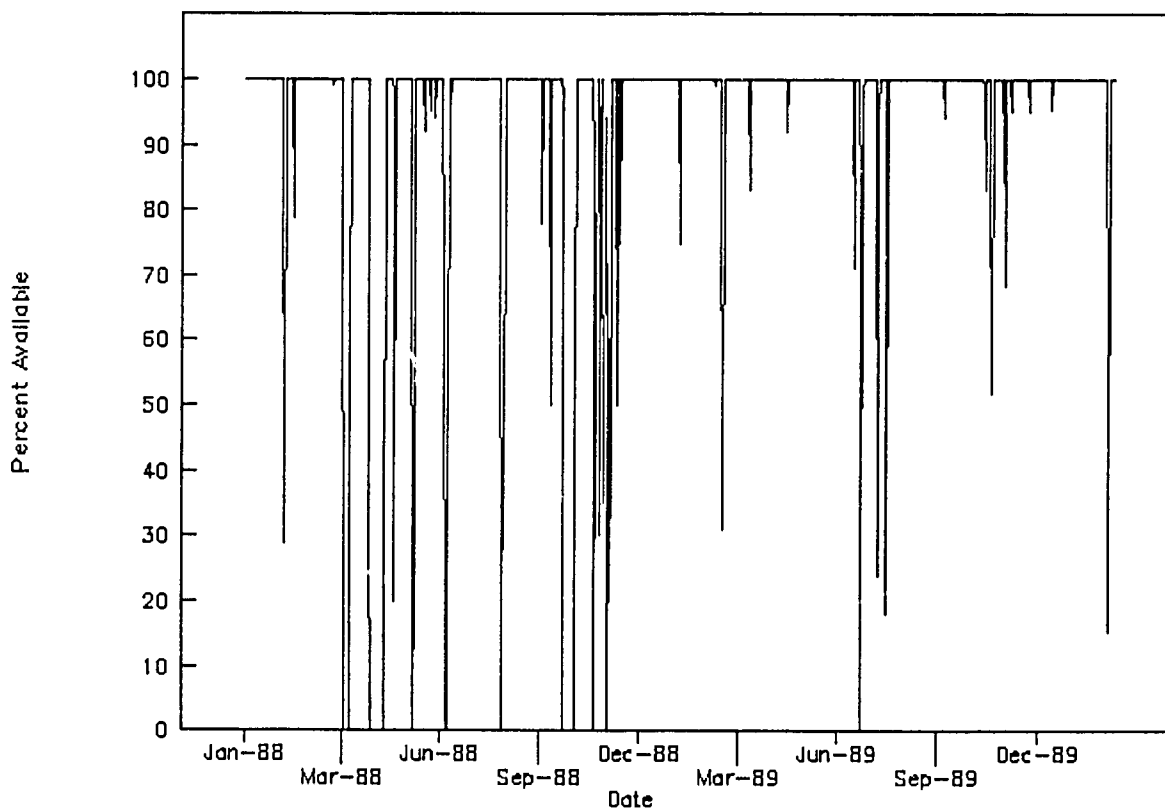
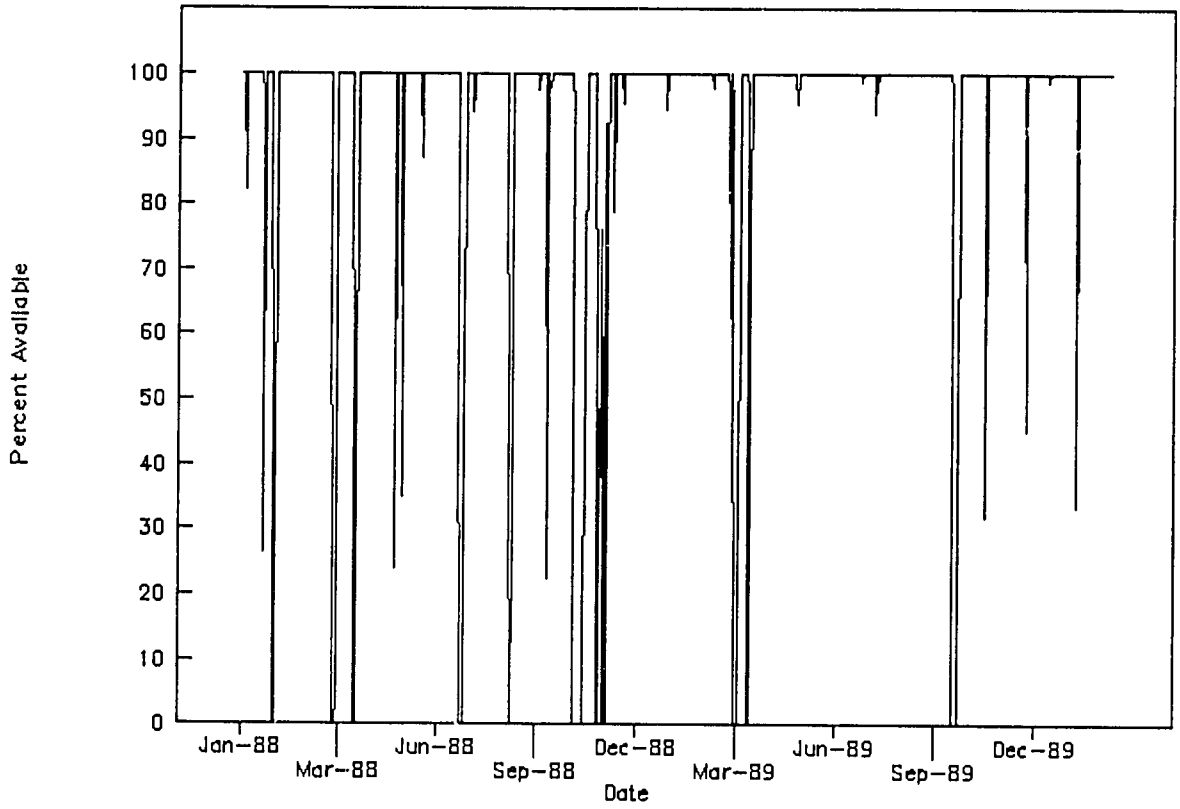


Figure 12. Guddu Plant Generator and Station Availabilities (cont.)

Availability of Gas Turbine Generator, G-9



Availability of Gas Turbine Generator, G-10

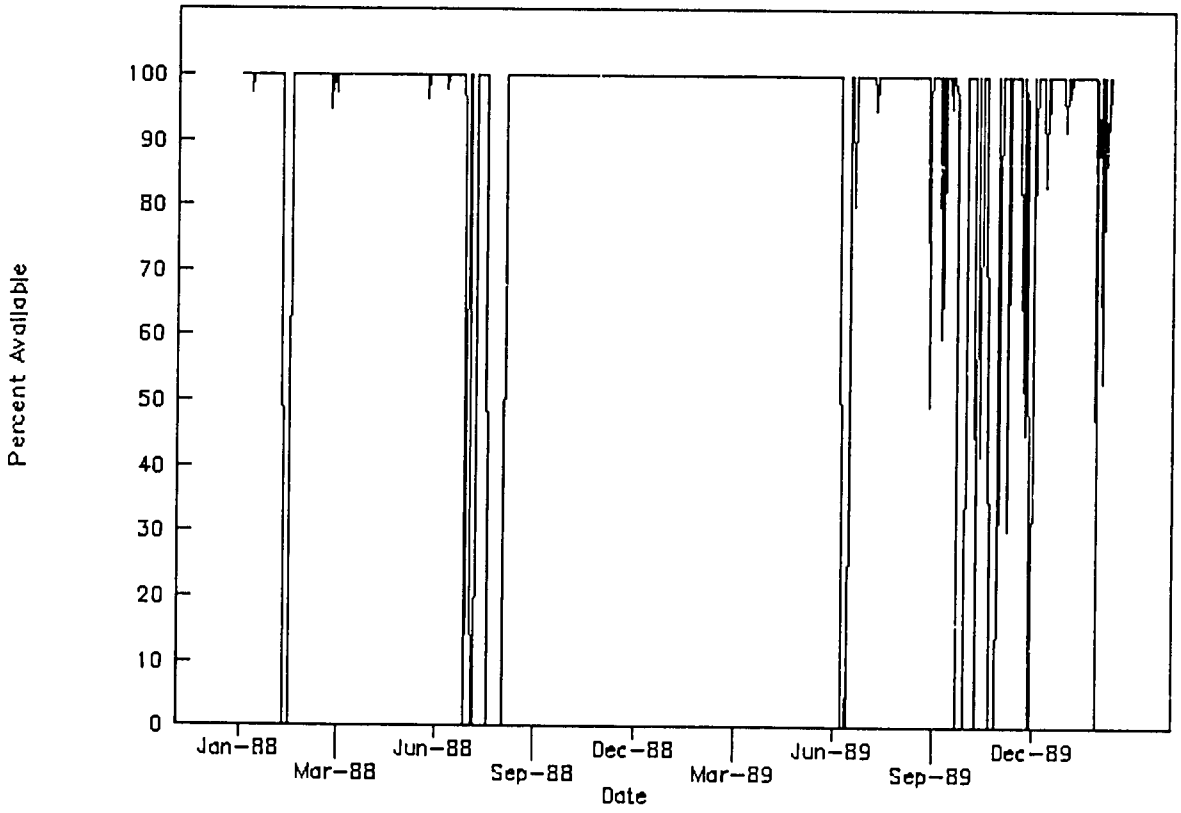


Figure 12. Guddu Plant Generator and Station Availabilities (cont.)

(Station Average is 76 Percent Over an
Operating History of 26 Months)

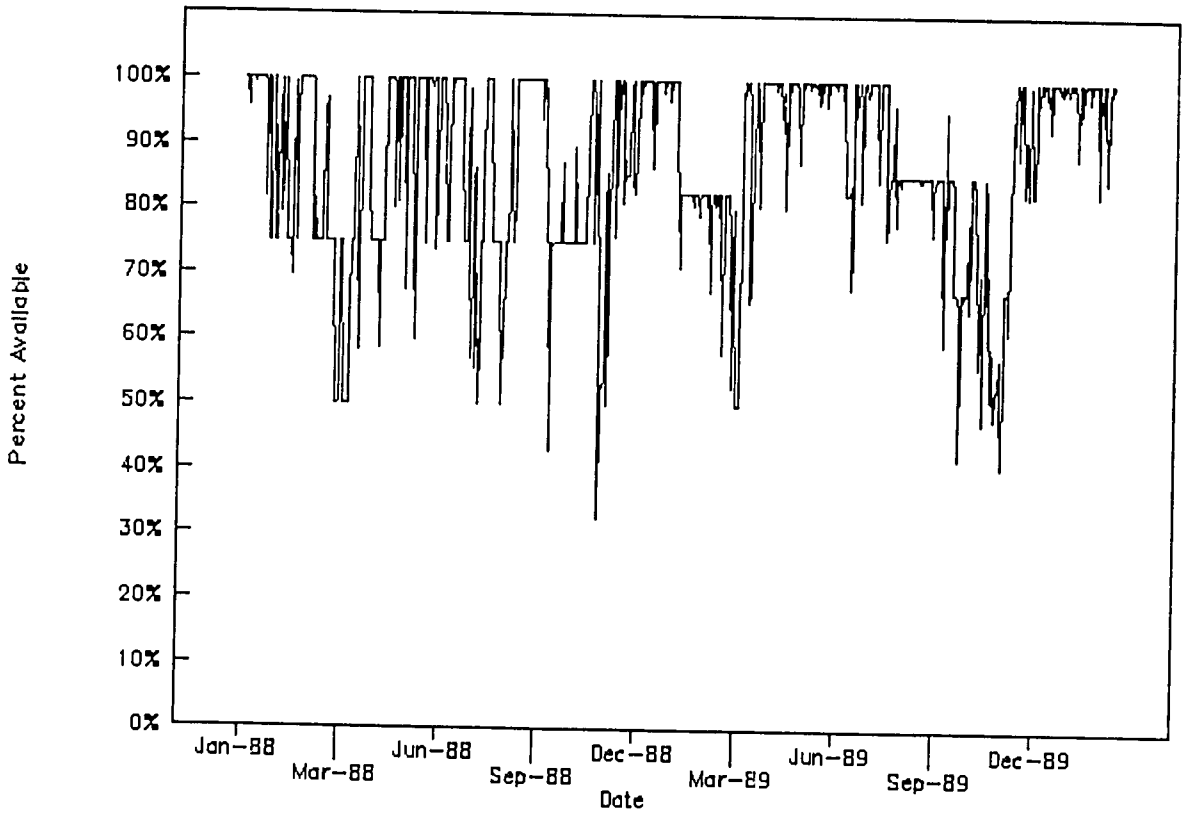


Figure 12. Guddu Plant Generator and Station Availabilities (cont.)

Source: Derived from data supplied by WAPDA, April 1990.

46

efficiency by the constant conversion factor of electric energy (860 kcal/kWh or 3,413 Btu/kWh); as heat rate decreases, efficiency increases.

The achieved net heat rate (lower heating value, LHV) at Guddu (Btu/kWh) on a month-to-month basis is indicated in Table 5. As can be observed in the table, once the plant achieves a level of consistent operation, it is able to perform at a monthly heat rate of about 8,200 Btu/kWh or less. However, monthly levels are consistently above these figures, resulting from operation of the gas turbines in a simple-cycle mode. Bearing in mind the severe shortages of power in Pakistan, such operation is understandable -- when an outage occurs in the steam turbine or HRSG, the HRSG is bypassed so that the gas turbines can provide power. As indicated in the specifications of the gas turbine, full load heat rate in the simple-cycle mode is about
12,000 Btu/kWh. Heavy usage of gas turbines in times of low steam turbine availability is indicated for the months of January and February 1988, and as recently as October and November 1989, when heat rates of over 10,000 Btu/kWh resulted.

The annual heat rate for 1988 (for the months of combined cycle operation, after the steam turbines came on line) was about 8,900 Btu/kWh and 1989 was slightly higher at 9,300 Btu/kWh. For the entire 26-month period, Guddu achieved an average heat rate of 8,860 Btu/kWh. Comparable values for a 400 MW gas-fired steam (reheat and regeneration) power plant are 9,000 Btu/kWh and 9,500 Btu/kWh for a 400 MW coal-fired steam plant. Steam plants of sizes comparable to the 100-150 MW units at Guddu would use simple Rankine cycle designs (without reheat or regeneration) and would achieve higher heat rates (about 10,500 - 11,000 Btu/kWh).

As shown in Table 7, efficiency for the Guddu combined-cycle power station has averaged 38 percent for its first 26 months of operation. In good months, the station is able to achieve an efficiency of 41 percent.

Availability and Reliability

Availability figures were obtained directly from WAPDA. These data include both forced outages and planned outages.

Monthly gas turbine generator availability statistics over the period January 1988-February 1990 are presented in Table 5, and annual availability rates are shown in Table 7. For 1988, monthly availability averaged 76.3 percent; for 1989, 76.0 percent; and for the first two months of 1990, 96.0 percent, for an average of 83 percent over the period studied. Maximum availability was attained in August 1989 (99.2 percent), but maximum generation

Table 7

Guddu Station Annual Availability and Heat Rates

Year	GTG Availability	STG Availability	Station Availability	Net Station Heat Rate (Btu/kWh)	Efficiency (%)
1988	77%	73%	76%	9,309	37
1989	76%	76%	76%	9,290	37
1990*	96%	99%	97%	8,281	41
26-month average	83%	83%	79%	8,960	38

* Data for 1990 cover the two-month period January-February only, which were months of steady operation. It is not expected that performance for the entire year was this good.

Note: GTG = gas turbine generator
STG = steam turbine generator

Averages for the year 1988 reflect September through December only; the forced outage rate is a 15-month average.

was attained in January 1990 (293,835 MWh), when gas turbine availability was 98.3 percent.

Data for steam turbine availability were not available until the September 1988 because the steam turbines were not commissioned until January 1988 (G-5) and the end of March 1988 (G-6). However, the average steam turbine availability rose from 76.2 percent in 1989 to 98.7 percent in the first two months of 1990.

Of perhaps greater interest is the life history of each plant, in terms of availability and outages. This can be presented in graphical format (Figure 12) or tabular statistics (Table 8).

A graphical presentation of daily availability shows a timeline, with the plant as either 100 percent available or not available (0 percent) in case of an outage. If an outage begins or

Table 8. Chronology of Plant Outages Greater Than 100 Hours in Duration

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Remarks
1	09-Feb-88	162.3	G-10	Routine maintenance	Planned
2	07-Mar-88	187.8	G-7	High flame spread in combustion section	Forced
3	16-Mar-88	545.8	G-7	Excessive vibration in bearing #3	Forced
4	31-Mar-88	156.1	G-8	High flame spread and vibration at 75 MW load	Forced
5	25-Apr-88	339.1	G-8	Overheating of torque converter	Forced
6	19-Jul-88	118.2	G-9	Combustion related problems	Forced
7	02-Aug-88	115.5	G-7	Short circuiting in gas valves	Forced
8	14-Aug-88	384.7	G-10	Trial run on steam turbine generator G-6	Planned
9	02-Oct-88	373.0	G-7	Modification work on bypass damper	Planned
10	18-Oct-88	252.9	G-8	Test synchronous condenser operation	Planned
11	30-Oct-88	251.5	G-9	Test synchronous condenser operation	Planned
12	19-Nov-88	146.6	G-7	Computer failure indicator problems	Forced
13	13-Dec-88	106.4	G-6	Approved shutdown of Gas turbine generator G-9	Planned
14	29-Jan-89	1398.3	G-7	Vibration and related problems	Forced
15	23-Mar-89	130.1	G-9	Combustion system and related problems	Forced
16	23-Mar-89	156.3	G-6	Combustion system and related problems	Forced
17	31-Mar-89	102.8	G-7	Repair work on gear box	Planned
18	01-Jul-89	120.1	G-10	Unit transformer damage	Forced
19	08-Aug-89	133.2	G-5	Heavy leakage from circulation pump	Forced
20	15-Aug-89	396.3	G-5	First GE Company inspection	Forced
21	01-Sep-89	720.0	G-5	Staff inspection	Planned
22	21-Sep-89	156.9	G-7	Combustion system inspection	Planned
23	01-Oct-89	678.0	G-5	First staff inspection	Planned
24	13-Oct-89	193.8	G-10	Heavy oil leakage from both sides of the generator	Forced
25	30-Oct-89	136.9	G-9	Boiler systems inspection	Planned
26	01-Nov-89	687.3	G-6	First staff inspection	Planned
27	12-Nov-89	178.1	G-10	Heavy vibration on 88PF motor	Forced
28	14-Nov-89	194.8	G-5	Fire observed at turbine bearing #1	Forced
29	19-Nov-89	202.8	G-7	Load Dispatch Center at Lahore requested Shutdow	Planned
	Total —>	8,725.2			

Source: Derived from data supplied by the Water & Power Developement Authority (Pakistan), April 1990.

ends during the day, or if the plant is subject to derating, an availability between 0-100 percent would result for the day.

In Figure 12 the daily availability of each of the Guddu plant's steam and gas turbine generators is summarized. In each graph, a break in the top line indicates that the unit is not 100 percent available due to an outage. The width of the gap is a direct indication of the duration of the outage. For example, the availability of steam turbine generator G-5 was interrupted in August and September 1989 due to both a forced outage (leakage from the circulation pump) and planned inspections, as shown in Table 8.

Figure 12 reveals the following:

- Steam turbine generators G-5 and G-6 have been characterized by frequent outages of short duration.

- Steam turbine generator G-5 was the first to be taken out for a long outage, and problems were encountered in bringing the unit back on line after this outage. As shown in Table 8, this outage began as an inspection on October 1, 1989 and a fire occurred in the turbine bearing upon restarting on November 14, 1989.

- While its experience is similar, steam turbine generator G-6 has generally performed more reliably than G-5, because of the single long outage at G-5.

- Among the gas turbines, unit G-7 experienced the longest outage and the most frequent outages. The longest outage began on January 29, 1989, due to vibration problems, and another long outage also occurred in March 1988 due to vibration.

- The most reliable gas turbine was unit G-10, especially for its first 18 months of operation. G-10 achieved one run of eight months without an outage. Outages became much more frequent on unit G-10 in the later months.

- The newer gas turbine units achieved higher availability during the study period, which could be attributed to a learning curve by the plant operators or the relative age of the units.

- Total station availability, as indicated in the daily curve, averaged about 83 percent. Given the shortage of capacity in Pakistan, it is perhaps significant to note that a minimum of 30 percent of plant rating was available -- there

were no days when Guddu was unable to take any load, and very few when less than 50 percent of capacity was available.

Figure 13 displays a breakdown of dowmtime by plant component. The top graph shows the relative unavailability of the gas and steam turbine generators, and the HRSG. The bottom graph shows the subsystems breakdown of unavailability for the largest contributor to plant downtime -- the gas turbine.[1]

Figure 14 provides a summary of the five plant subsystem groups that contributed most to plant downtime, and the percent of downtime attributable to each. Outages are divided into planned and forced.

Figures 15 and 16 display the plant's heat rate as a function of plant utilization and availability, respectively.

Planned and Forced Outages

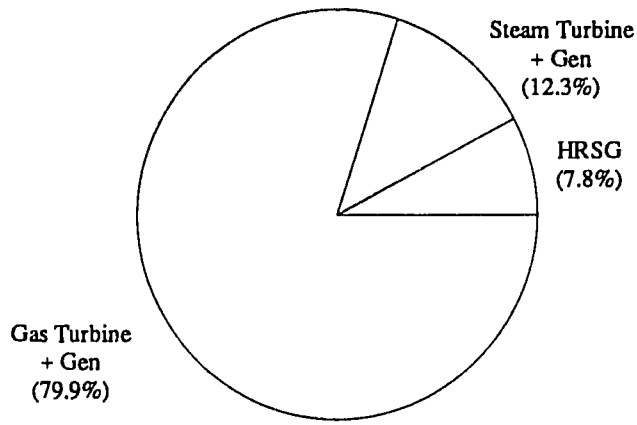
For a generation unit, outages are defined as a temporary loss of electricity supply. Daily outage records for the Guddu plant over the period January 1988 through February 1990 are found in Appendix A. In summary, forced outages (unexpected failures in plant operation) totaled 12,277 hours and planned outages (maintenance-related plant stoppages) totaled 9,755 hours. Thus, a total outage time of 22,033 hours was recorded for the plant's 26-month operating history.

Table 8 displays a chronology of Guddu plant outages of greater than 100 hours in duration and a brief explanation of each. Of these 29 outages, 14 were planned outages. The nature of preventive maintenance activities such as hot gas-path and major inspections requires that the turbine be removed from service for a number of days.

Planned outages consist of "running" and "shutdown" inspections. The "running" inspections are usually conducted during off-peak periods and include routine servicing during start-up and while the unit is operating. They provide information on the general condition of the turbine and accessory equipment. The "shutdown" inspections include

[1] The calculation method used to develop these figures was based on the method used by GE to analyze the performance of its U.S. plants. A comparison of the results shows that the controls and accessories are the largest contributor to downtime in U.S. plants, followed by combustion systems, turbine, balance-of-plant, and generator. The results for Figure 13, however, were very similar to those obtained by GE.

Guddu 600 MW: Subsystems Contributing to Combined Cycle Plant Unavailability



Guddu 600 MW: Subsystems Contributing to Gas Turbine Plant Unavailability

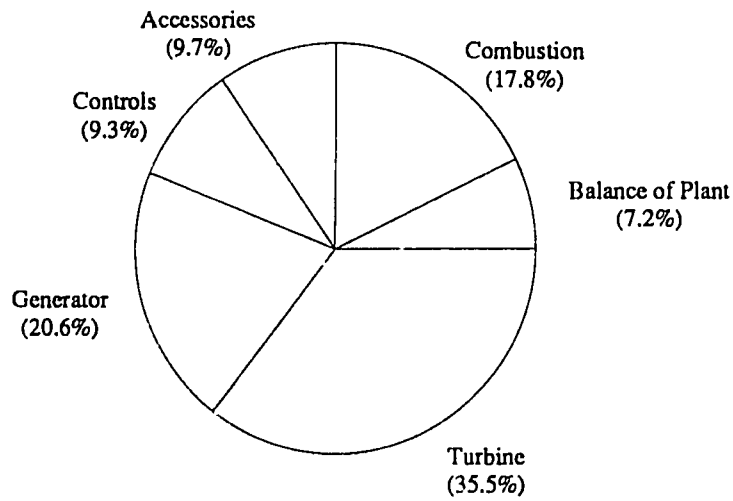


Figure 13. Factors Affecting Availability

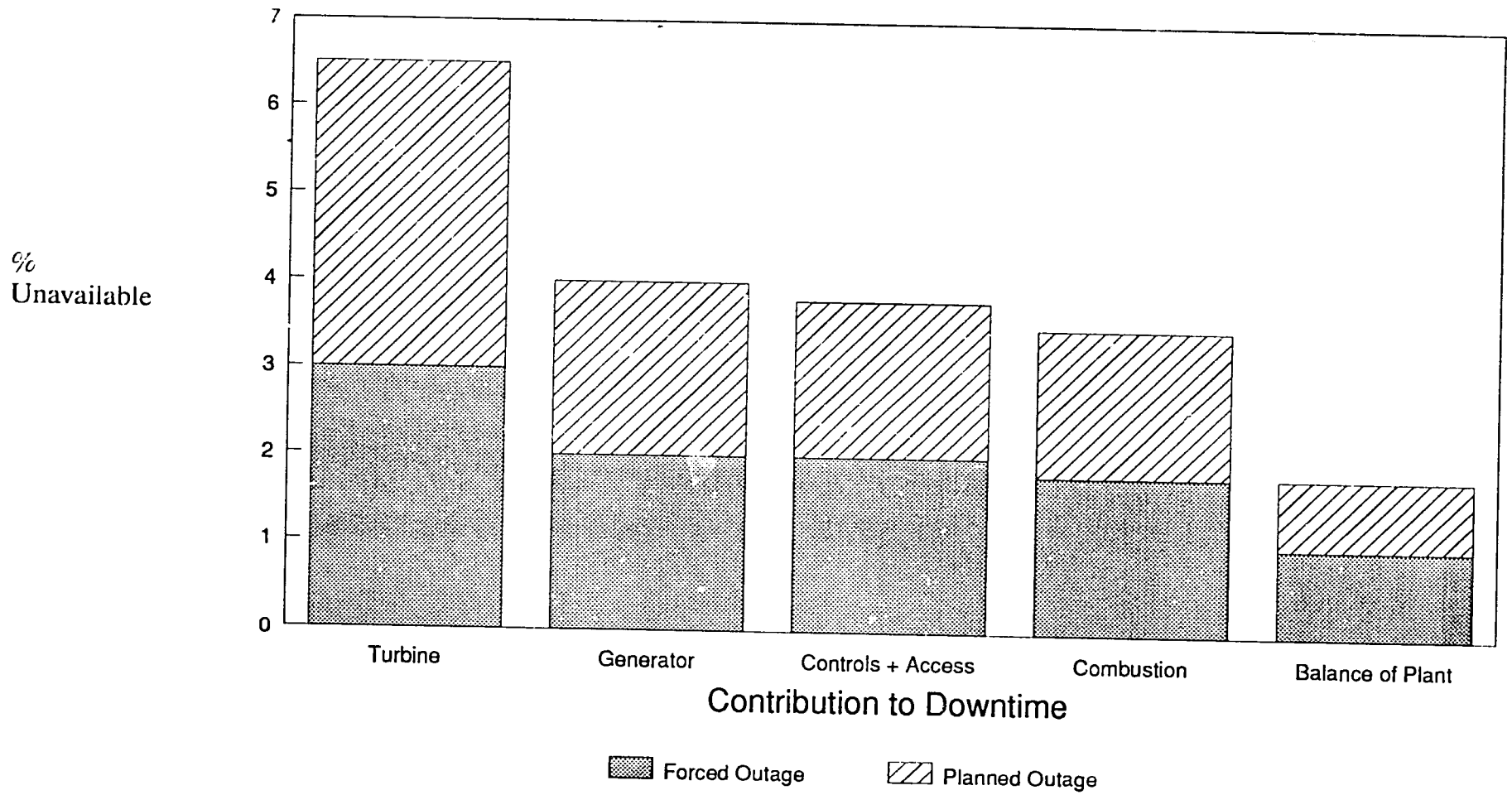


Figure 14. Guddu Station: Top Five Systems Contributing to Gas Turbine Downtime

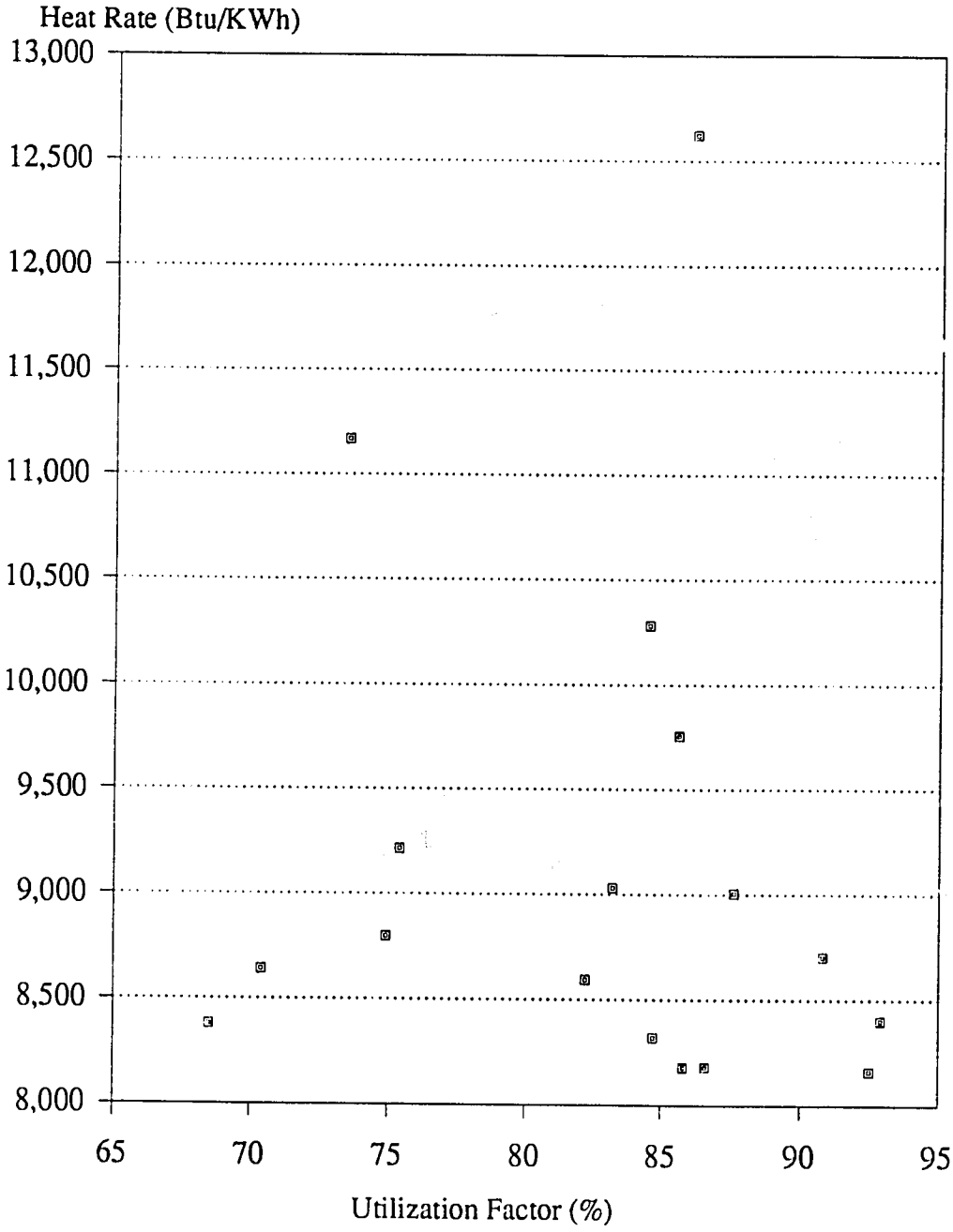


Figure 15. Guddu Plant Utilization Factor vs Heat Rate

Source: Water and Power Development Authority of Pakistan (WAPDA), April 1990

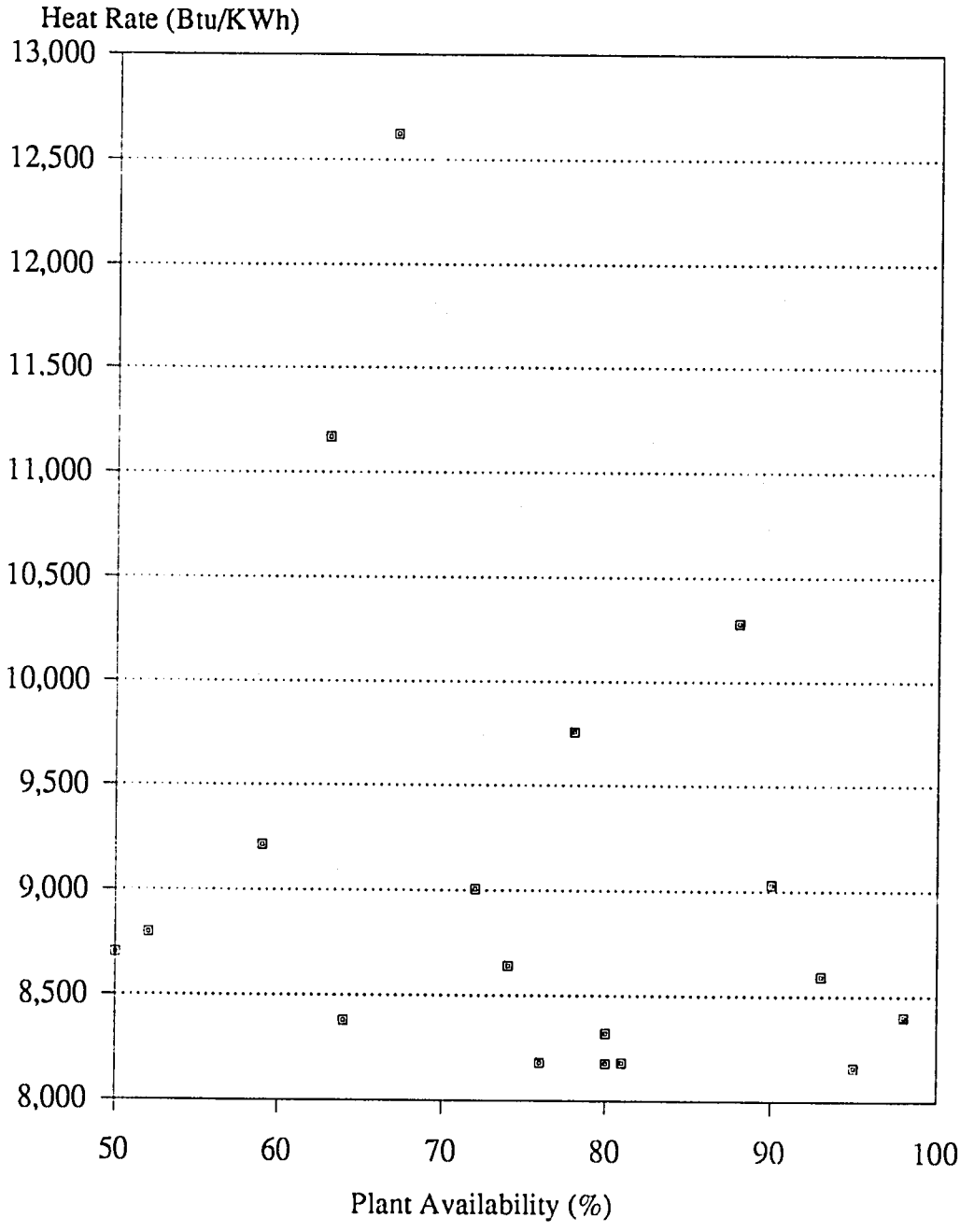


Figure 16. Guddu Plant Availability vs Heat Rate

Source: Water and Power Development Authority of Pakistan (WAPDA), April 1990

combustion, hot-gas path, and "major" inspections. Together, planned outages accounted for 46 percent of the plant outages greater than 100 hours.

Forced outages arise from the diagnosis and repair of failures to start, automatic trips based on instrument readings, and manual shutdowns due to alarms or other problems. Of the 29 Guddu plant outages of greater than 100 hours in duration, 13 were forced. Of these, combustion-related problems (three outages) and vibration problems (three outages) were the most frequent cause, with vibration causing nearly one-quarter of the outage hours. Two of these vibration-caused outages were among the station's ten-largest outages, as shown in Table 9. Table 10 displays the Guddu plant's forced outage rate.

A Typical Day

February 12, 1990 was selected by WAPDA as a typical day at the Guddu power plant. In fact, this was one of the station's best days. Table 11 provides a summary set of operating and performance data for the plant on that day. Performance curves for the Guddu plant are displayed in Appendix B.

Table 9

Ten Longest Outages at Guddu Power Station by MWh Lost

SN	Date	Outage (hrs)	Gen. No.	Outages	MWh lost
1	29-Jan-89	1,398.3	G-7	Compressor failure and oil leakage resulting failure of the starting motor	152,762
2	01-Sep-89	720.0	G-5	First General Electric Company inspection	66,232
3	01-Nov-89	687.3	G-6	First General Electric Company inspection	63,225
4	01-Oct-89	678.0	G-5	General Electric Company inspection	62,367
5	16-Mar-88	545.8	G-7	Excessive vibration on bearing #3	59,629
6	15-Aug-89	396.3	G-5	General Electric Company inspection	36,452
7	14-Aug-88	384.7	G-10	Due to trial run of steam unit G-6	42,030
8	02-Oct-88	373.0	G-7	Bypass damper	40,748
9	25-Apr-88	339.1	G-8	Failure of torque converter	37,047
10	18-Oct-88	252.9	G-8	Testing of synchronous condenser operation	27,624
	Total	5,775.3			588,116

Source: Derived from data supplied by Water and Power Development Authority of Pakistan (WAPDA), April 1990.

Table 10. Guddu Plant: Availability, Forced and Planned Outage Rates

Date	GTG avail-ability	GTG forced outages	GTG planned outages	STG avail-ability	STG forced outages	STG planned outages	Station avail-ability	Station forced outages
Jan-88	93%	1%	6%	na	na	na	na	na
Feb-88	90%	2%	8%	na	na	na	na	na
Mar-88	75%	23%	1%	na	na	na	na	na
Apr-88	77%	23%	0%	na	na	na	na	na
May-88	90%	8%	1%	na	na	na	na	na
Jun-88	94%	5%	0%	na	na	na	na	na
Jul-88	88%	9%	3%	na	na	na	na	na
Aug-88	81%	9%	10%	na	na	na	na	na
Sep-88	72%	9%	19%	71%	na	na	72%	na
Oct-88	53%	32%	15%	75%	na	na	59%	na
Nov-88	48%	29%	23%	56%	na	na	50%	na
Dec-88	66%	18%	16%	92%	1%	7%	74%	12%
Jan-89	72%	8%	19%	99%	0%	1%	80%	6%
Feb-89	50%	27%	23%	98%	2%	0%	64%	19%
Mar-89	40%	46%	14%	80%	8%	11%	52%	33%
Apr-89	68%	15%	17%	95%	1%	4%	76%	10%
May-89	74%	23%	3%	94%	5%	1%	80%	17%
Jun-89	75%	18%	8%	96%	4%	0%	81%	13%
Jul-89	90%	3%	6%	99%	1%	0%	93%	2%
Aug-89	99%	1%	0%	60%	34%	6%	88%	12%
Sep-89	91%	1%	8%	49%	26%	25%	78%	9%
Oct-89	77%	5%	17%	43%	33%	24%	67%	15%
Nov-89	81%	8%	11%	21%	69%	10%	63%	28%
Dec-89	95%	3%	2%	79%	11%	9%	90%	6%
Jan-90	98%	1%	1%	99%	2%	0%	98%	1%
Feb-90	94%	2%	4%	99%	1%	0%	95%	2%
Summary Statistics								
avg. 1988	77%	14%	9%	73%	1%	7%	64%	12%
avg. 1989	76%	13%	11%	76%	16%	8%	76%	14%
avg. 1990*	96%	2%	2%	99%	1%	0%	97%	2%
avg. 26 mth	78%	13%	9%	54%	8%	4%	52%	12%

Note: GTG = gas turbine generator, STG = steam turbine generator, na = not available
* data and averages for the year 1990 reflect January and February only
numbers in table may not add up due to rounding errors, averages for the year 1988 reflect September thru December data only, Station outage rate is for 15 months.
Source: Derived from WAPDA (Pakistan) data obtained April 1990.

Table 11. Guddu Plant: Recent Typical Day Statistics

Date: February 12, 1990
Maximum ambient temperature: 21 degrees C
Minimum ambient temperature: 13 degrees C

Generator Number	G-5	G-6	G-7	G-8	G-9	G-10	TOTAL
A. Unit Parameters							
1. Energy generated, MWh	2,304	2,309	2,531	2,540	2,510	2,519	14,713
2. MVARH	29	4	188	258	519	100	1,098
3. Generator running hours	24	24	24	24	24	24	144
B. System Parameters							
1. Total MVAR generated	1,098 MVARH						
2. Energy generated on gas	14,713 MWh						
3. Energy generated on oil	0 MWh						
4. Auxilliary consumption	197,496 KWh						
5. Station use	1.30%						
6. Energy exported	20,120 MWh						
7. Energy imported	9,500 MWh						
8. Power factor	0.997						
9. Utilization factor	97.1%						
10. Availability	100%						
11. Gross Heat Rate	8,199 Btu/KWh						
12. Net Heat Rate	8,308 Btu/KWh						
13. Maximum load							
-time	2400 hrs						
-load	630 MW						
14. Minimum load							
-time	0400 hrs						
-load	520 MW						
15. Total fuel consumption							
a. Nat. gas	157,720 MCF						
b. Diesel	0 lit						
16. Diesel stock position	4,756,900 lit						

Source: Water & Power Development Authority (Pakistan), April 1990.

CHAPTER 4: TALKHA POWER PLANT, EGYPT

The 300 MW combined-cycle Talkha power plant is located in Talkha (the upper Nile delta), about 120 km from Cairo. The plant is owned and operated by the Egyptian Electricity Authority (EEA), which is Egypt's major generating utility, providing bulk power supply to several municipal and regional distribution agencies.

The Talkha plant was previously a simple-cycle gas turbine station. The plant was converted to combined cycle by installing the HRSG and steam turbine generators for a total cost of U.S. $70.3 million. Of this, the foreign exchange component ($60.7 million) was financed by an A.I.D. loan. The remaining local currency portion (US $9.6 million equivalent, or 14 percent of the total costs) was financed by the Arab Republic of Egypt. The Talkha project was completed as a fixed price, turnkey project.

4.1 CONSTRUCTION HISTORY

With its energy demand forecast to increase at an estimated 7.5 percent per year through the year 2000, Egypt has embarked on an ambitious program to construct 36 individual power projects in a ten-year period (see the table below). Seven of the planned power projects will utilize combined-cycle technology (1,375 MW total capacity). It is also important to note that during this period, Egypt is forecast to evolve from being an oil-exporting country to an oil-importing country, if present domestic demand trends for oil continue. Thus, greater exploitation of associated and non-associated natural gas is an important part of Egypt's energy policy.

In early 1987, the EEA announced the signing of a contract with General Electric (GE) of Schenectady, New York to convert the Talkha gas turbine-powered generating station into what was to be the country's first combined-cycle power plant. This project was intended to increase the existing plant's capacity from 200 MW to 300 MW.

The original Talkha plant was nine years old and consisted of eight General Electric MS-5001 gas turbines configured in simple cycle with a total output of 200 MW. The retrofit of the Talkha plant involved converting the eight original gas turbines into two independent STAG powerplants.

Egyptian Electricity Authority: Generating Expansion Plan

Year	Combined-Cycle (MW)	Other (MW)	Total (MW)
1988/89	100	1,500	1,600
1989/90	0	100	100
1990/91	350	1,800	2,150
1991/92	25	800	825
1992/93	300	600	900
1993/94	0	865	865
1994/95	0	1,200	1,200
1995/96	0	1,200	1,200
1996/97	600	600	1,200

The Talkha plant began commercial operation in August 1989, 56 days later than the planned commissioning date. This relatively slight delay largely resulted from delays in the plant startup and test phase. Control system fine-tuning and operator training requirements were factors contributing to these delays. The duration from the beginning of construction to the commencement of commercial operation was as follows:

	Unit 1	Unit 2
Planned	670 days	730 days
Actual	786 days	786 days
Difference	116 days	56 days

4.2 PLANT DESIGN

The converted Talkha power plant consists of two independent General Electric STAG 400 combined-cycle power plants. Each STAG plant contains four gas turbine generator units, four heat recovery steam generators (HRSGs), one steam turbine generator, and mechanical auxiliary equipment. Start-up and on-line control systems and an integrated

system were included to support the General Electric-supplied power generation equipment. In addition, advanced technology hot-gas path components were installed for retrofit of the gas turbines.

The use of General Electric Company's "Advanced Technology Hot Gas Path Parts Package" as a major component of EEA's uprating scheme is expected to result in an improved heat rate, longer inspection intervals, and greater output capability.

The Advanced Technology Hot Gas Path Parts Package consists of the following major items:

- combustion liners
- transition pieces
- first-stage buckets
- first- and second-stage nozzles.

These improved design components will be installed in the gas turbine system. In order to convert simple-cycle gas turbines to STAG combined-cycle plants, further modifications to the gas turbine such as exhaust duct redesign, additional controls for combined cycle, and inlet guide vane redesign to ensure maximum exhaust temperature were undertaken.

The Talkha plant is designed to operate as a baseload unit, as a spinning reserve, or part-load unit. In daily operation, the plant can be started and brought to full base load in less than one hour, with approximately 65 percent of power available in 15 to 20 minutes. Its equipment has been designed to operate at close to full load efficiency over an extended range. When the plant is to be loaded at lower levels, individual STAG plants, gas turbines, and steam turbines can be shut down to permit the rest of the plant to run at higher efficiency. The gas turbines, for example, are equipped with variable inlet guide vanes that improve the part-load heat rate and minimize steam temperature decrease as load is reduced.

Each STAG combined-cycle power plant can be configured in a variety of ways to meet load demand. The generation equipment can be operated in the simple-cycle mode or in the combined-cycle mode. In the simple-cycle mode, the gas turbines are operated with the exhaust gas bypassing the heat recovery steam generators. Only in the combined-cycle mode is the steam cycle equipment operational.

62

Fuel

The Talkha plant is designed to be fueled by natural gas or distillate fuel oil (known in Egypt as Solar). The plant capacity is derated slightly when oil-fired, as shown below.

	Total Output (MW)	
Fuel	Natural Gas	Fuel Oil
Gas Turbines (8)	201.80	198.04
Steam Turbines (2)	101.06	100.64
Auxiliary Power	(0.78)	(0.78)
Net Output	302.08	297.90

4.3 PLANT OPERATIONS

At the time of this writing, only a limited amount of information was available on the operation of the Talkha plant. When EEA responded to the request for data, the plant had been in combined-cycle operation for only five months.

Station Availability

The availabilities (the amount of time that a power plant is available for operation) of the Talkha plant's steam and gas turbines, and the overall station as, as recorded by EEA, are shown below.

Talkha Station Availabilities

1989	Gas Turbines	Steam Turbines	Station
August	87%	88%	87%
September	97%	67%	87%
October	87%	54%	76%
November	86%	86%	86%
December	88%	86%	87%
Average	89%	76%	85%

In the first two months since the plant began operation (September and October), a significant reduction in the availability of the steam turbine generation system is apparent. These first months of operations included contractor-supervised run-in periods and post-acceptance testing adjustments, with the following two months including operating staff training and familiarization. Availability returns to the initial high levels after November.

Efficiency

Plant efficiency during the first five months of operation was significantly below design, as a result of operation in the simple-cycle mode for a significant portion of this period. However, the data provided indicate that the reconfigured plant is operating effectively. EEA maintains that this was planned as part of the start-up, run-in, and operator training exercises. Plant heat rates and efficiency for the first five months of operation are as follows:

	Efficiency	Net Heat Rate (Btu/kWh)
August 1989	34%	10,057
September 1989	30%	11,427
October 1989	28%	12,069
November 1989	33%	10,443
December 1989	33%	10,357
Average	31%	10,871
Fuel Load		
Performance Guarantees	40%	8,360
Gas Turbine Only	26%	12,200

Appendix C provides a detailed description of the Talkha plant's operating procedures.

Generation

Power generation during the first five months of the Talkha plant's operation is listed below.

	Gas Turbine MWh	Steam Turbine MWh	Total MWh	Station Use Percent
August	109,674	55,025	164,699	1.59
September	109,767	39,023	148,790	1.30
October	119,860	31,018	150,878	1.31
November	106,034	47,146	153,180	1.36
December	117,449	52,876	170,325	1.37
Average				1.39

The Talkha plant's capacity factor, which is the ratio of net generation to nameplate rating, was as follows:

August 1989	74%
September 1989	69%
October 1989	68%
November 1989	71%
December 1989	77%
Average	72%

The station capacity factor is shown in Figure 17. Figure 17 compares the station capacity factor against the net heat rates reported for the first five months of operation. As expected, reported plant heat rates are sensitive to the capacity factor and efficiency drops markedly when utilization falls below 70 percent.

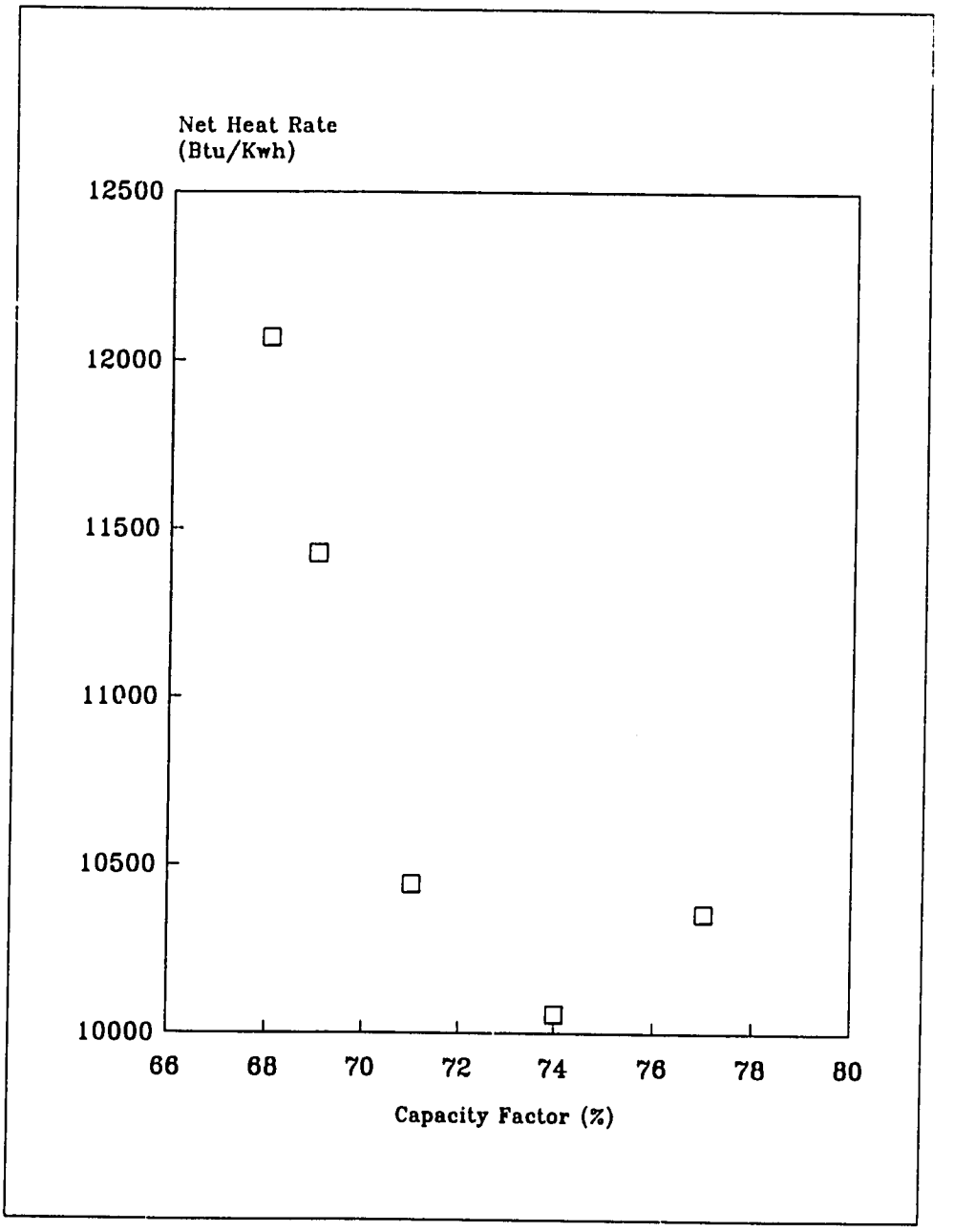


Figure 17. Talkha Plant Capacity Factor vs. Heat Rate

Source: Egyptian Electricity Authority, 1990

Utilization Factor

During the first five months of operation, the Talkha station's utilization factor (ratio of generation to potential generation only for times when plant was available) averaged 85 percent. This high value indicates that the Talkha station was generally dispatched by EEA as a baseload plant during its first five months of operation. Listed below are Talkha's monthly utilization factors for the first five months of operation.

August 1989	85%
September 1989	79%
October 1989	89%
November 1989	82%
December 1989	88%
Average	85%

CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

5.1 CASE STUDY CONCLUSIONS

Combined-cycle power plants have been installed in Pakistan and Egypt under A.I.D.-assisted projects. These installations now have a demonstrated track record, and can serve as case studies for other developing countries. The early performance data from these plants have been assembled, and the results of the study at Guddu and Talkha provide the basis for a number of conclusions, as listed below.

Compared to coal-fired steam plants, natural gas fired combined-cycle technology has now been demonstrated in developing countries to have a number of advantages. The advantages are summarized below:

- **Lower capital cost per megawatt** - The 600 MW Guddu project cost $500 per kilowatt (1982 US$), whereas a standard pulverized coal plant of the same rated capacity would have cost $800 per kilowatt at the time. In the 1990s and beyond, it will be increasingly difficult to find a site, or to obtain funding from multilateral development banks, for a coal-fired plant unless its design includes environmental control features (such as fluidized bed combustion or wet scrubbers). Thus, in 1990 US dollars, the cost of combined-cycle technology is about $600 per kilowatt, whereas competing coal technologies cost $1,200 per kilowatt or more.

- **Shorter construction schedule** - The 600 MW Guddu project delivered power from its first generator some 31 months after construction started, whereas a coal-fired station would probably have required 48 months. Further, the modular nature of combined-cycle technology allowed the units to be phased into service.

- **Similar availability** - The 600 MW Guddu plant achieved an average availability of 76 percent for the first 26 months of operation in the combined-cycle mode. This figure is on par with that at WAPDA's steam stations.

- **Higher efficiency** - For the first 26 months of operation, actual thermal efficiency at Guddu averaged 38.5 percent (a heat rate of 8,863 Btu/kWh). This

compares favorably to an average of 34 percent (10,000 Btu/kWh) for coal-fired plants in the United States.

- **Reduced environmental impact** - Compared to coal-firing, natural gas combustion produces far lower emissions of the oxides of sulfur and nitrogen, which cause acid rain. Because its hydrogen to carbon ratio is much higher than that of coal, gas combustion leads to far lower emissions of carbon dioxide (CO_2), the leading greenhouse gas contributing to global climate change. In addition, local pollution is reduced because of the negligible particulate emissions and ash resulting from gas firing.

Compared to those in industrialized countries, combined-cycle plants in developing countries have experienced lower availability and efficiency. To date, the levels of reliability achieved have been lower, but this may have been due to cautious operation, as evidenced by the long planned outages for inspections. However, the data available do not permit conclusions to be drawn. Further investigations into the problem are recommended. In gas turbine-based cogeneration installations in developing countries, such as found in most ammonia/urea fertilizer manufacturing plants, much higher levels of availability have been achieved, typically over 90 percent for several years of operation. Production in the fertilizer plant depends on the gas turbine/heat recovery steam generator system, motivating a sense of urgency to keep it operating, which may be absent in a utility power plant.

Operations in a power shortage situation induce stresses that may affect long-term reliability or equipment life. An urgent need for the electric power from the plant may result in decisions to delay preventive maintenance activities or to operate at reduced load instead of taking a forced outage in response to instrument readings for which the manufacturer recommends corrective action.

- **Overloading** - In times of crisis, a plant may be operated above its rated limit on occasion for brief periods. The 600 MW Guddu plant is typically loaded to its maximum rating, and thus must go into overload to supply any additional energy.

- **Planned outages foregone** - Delays due to outages for inspection and preventive maintenance are usually the first actions taken in times of a capacity shortage.

- **Frequent trips** - In a utility system strained for capacity, a number of generators are running at full load. Thus, the loss of any one generator will cause all the remaining generators to attempt to carry the load, thus sending

them into an overload condition which will lead them to trip out (shut down). Inadequate preventive maintenance and improper operation can also cause frequent trips. With each start-up and shut-down, severe thermal and mechanical stresses are imposed on turbine blades, which cause fatigue and shorten life. The operation at Guddu has been characterized by frequent trips.

- **Defeat of safety interlocks** - In times of crisis, innovative plant operators and engineers will discover ways to bypass or otherwise defeat safety systems that would otherwise cause the plant to trip. One example, observed at Guddu, is operation at reduced MW load as a response to flame spread temperature readings. Instead of taking the plant out of service to correct the problem by adjusting nozzles, reducing the load by a few percent reduced the temperatures to within specifications.

5.2 RECOMMENDATIONS FOR ELECTRIC UTILITIES IN DEVELOPING COUNTRIES

Based on the results of the case studies and a general level of awareness of the plans of developing countries for expansion in the power sector in the next decade, the following recommendations are made.

1. **Re-examine estimates of capital cost, availability and efficiency for combined-cycle technology in system expansion plans.** The information available from the Guddu and Talkha plants provides a basis for developing estimates of inputs to be used in generation capacity planning. These data confirm that the availability of combined-cycle technology will be at least as good as coal-fired plants, whereas some utilities have shown lower availability. If availability is increased in an expansion plan estimate, the calculated cost of electric energy generated (such as in US cents per kWh) will be lower, making the option more attractive.

2. **Coordinate power sector expansion planning with gas development.** Combined-cycle power plants must be fired with natural gas to be economic (firing with distillate petroleum is technically feasible, and provides a back-up fuel for greater reliability). Thus, gas availability is a necessary precursor to their application. If gas reserves are present, combined-cycle power plants offer a good way to develop a baseload use for the gas, which can provide economic viability to the gas development project. It may also be economic to import gas, if a neighboring country has low-cost gas reserves -- in

Japan, liquified natural gas (LNG) is imported from Southeast Asia for use in combined-cycle plants.

3. **Consider environmental costs of coal-fired systems.** The coal-fired power plants of the 1990s and beyond are likely to use different technologies than the plants now in place in developing countries. A fundamental shift toward greater environmental awareness is growing worldwide, and the multilateral development banks and other funding agencies are responding. However, the expansion plans of many utilities assume that basic coal-fired plants will continue to be used. In reality, the capital cost of a coal-fired plant, built to the environmental specifications likely to be required by the funding agencies, may be 30-50 percent higher than that indicated in current expansion plans. Taking this cost into account would increase the calculated cost of electricity from coal-fired plants. Beyond the increased capital cost, there is also work in progress among economists to value other environmental effects such as acid rain and global warming. Attaching any value whatsoever to these effects would also increase the cost of electricity supplied from coal, as compared to that from gas-fired plants.

4. **Consider retrofitting existing gas turbine stations to combined cycle.** The Talkha plant demonstrated combined-cycle retrofit technology. A combined-cycle retrofit will add to existing generation capacity, improving overall plant efficiency. Depending on the utility's load growth and daily load profile, it may be economically feasible to install steam bottoming cycles on existing gas turbine installations. The investment cost of a combined-cycle retrofit can be recovered through the lower fuel costs as a result of improved efficiency in the use of existing generation. Of course, the feasibility of such a project would depend on the condition of the existing gas turbines and their ability to be upgraded to handle the higher duty cycles required for intermediate or baseload power.

5. **Consider the human element in combined cycle projects.** Electric utilities have operations and maintenance personnel who are familiar with gas turbine equipment and steam turbines plants, but usually not <u>both</u>. Thus, additional staff members with the requisite skills are required in the combined-cycle plant. Further, as the case studies at Guddu and Talkha show, the process of bringing combined-cycle plants on line in developing countries has proceeded relatively slowly. The following steps are recommended to accelerate the process:

   - Increase the involvement of selected local operating and maintenance plant staff in the design and construction phases. In this way, they will be familiar with

the details of the installation. They will have time to study the equipment and its requirements. They will feel a greater sense of pride and "ownership" in the site. This effect has been demonstrated to improve quality in most working environments.

- Increase training of plant staff, including long-term internships in plants in industrialized countries. By working in a well-run combined-cycle power plant, such as those of U.S. utilities, the plant staff will be able to become familiar with operations and maintenance procedures in their own plant. This transfer of know-how can best be accomplished by apprenticeships of one year or longer. During this 12-month period, the apprentice should serve as an assistant to U.S. utility plant staff working in his primary job (at least six months), with the next-level supervisory job above him (at least three months), and in at least one job in a different area of the plant.

- Plant staff, once trained, should have viable careers and salaries that will enable their skills to be maintained at the plant. There is an unfortunate tendency toward migration away from careers in electric utilities, especially in developing countries. This skills migration occurs not only as emigration to other countries but also within the country, as the state-owned utilities lose capable staff to higher-paying private sector employers. The trend toward greater involvement of the private sector in power generation in developing countries is expected to improve this situation, but this trend is proceeding very slowly. For technologies of greater complexity, such as combined cycle, this problem is exacerbated.

- Ensure that preventive maintenance systems and operating procedures are enforced. Operators need to be given the correct signals. Often, "productivity" is the only objective, and thus performance is judged only on the basis of kilowatt-hours generated. Efficiency needs also to be considered, as this relates to the cost of production. This is especially critical in the combined-cycle system, since in installations with a bypass damper (such as Guddu and Ta[illegible], it is possible to generate power from the gas turbine generator alone, albeit at high cost. Running a gas turbine station as a baseload station results in the generation of high-cost power, but this can happen if kWh is the only criterion. Finally, quality needs to be considered -- in electric power systems quality relates to disturbances and outages. Utilities should consider the long-term effects of operation in a crisis mode, and even consider load-shedding so as to carry out planned outages for preventive maintenance.

6. **Evaluate combined-cycle technology in comparison to alternative technologies, considering the expected load characteristics and gas supply risks.** In cases where the electric utility's load forecast does not warrant a baseload plant, a simple-cycle unit, operating as a peaking plant, could be a superior option. Conversion to combined-cycle at a later date can be included in the plant design so that as the load matures, the plant can supply the additional energy needed by moving to intermediate or baseload operation. In cases of uncertainty of gas supply, the size and complexity of the combined-cycle system result in a design that is not nearly as flexible as a packaged simple-cycle gas turbine. With today's aeroderivative gas turbine achieving design efficiencies of up to 38 percent at full load, the use of a packaged unit offers the opportunity to quickly exploit a new gas find at good efficiency, while still maintaining the option of relocating the unit after a few years.

5.3 RECOMMENDATIONS FOR INTERNATIONAL DONORS

This report is intended to serve as guidance for electric utilities in developing countries. Many of these utilities are financed by the multilateral development banks and by bilateral donors, including A.I.D. This section is intended to provide recommendations that can be used by these international donors to develop their policies and to assist developing countries in general to adapt to the shift to combined-cycle technology.

1. Continue to pursue the development of natural gas resources, using combined-cycle power plants as bulk consumers of gas.

2. Hold a workshop on combined-cycle technology for electric utility expansion planners.

3. Establish a system of training for combined-cycle power plants, focusing on internships in plants in industrialized countries.

4. Develop an inventory and tracking system database to document the combined-cycle experience in developing countries, expanding upon the case studies of Guddu and Talkha. Include not only design data but also operating performance statistics.

5. Continue the detailed longitudinal study of Guddu and Talkha, by yearly updates. Obtain detailed data on Talkha to expand the scope of study to a par with Guddu.

6. Document experience in developing countries with other modern technologies, which generate or consume substantial amounts of energy, or energy-saving technologies such as:

- clean coal combustion technologies
- renewable energy technologies
- cogeneration in industrial facilities
- energy-efficient electric end-use equipment (lights, motors, etc.)
- energy effects of architectural designs for buildings
- advanced, low-energy industrial processes
- public transportation systems
- energy-efficient passenger aircraft
- communications systems
- water and wastewater treatment systems.

APPENDIX A

Guddu Plant Outage Records

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
1	05-Jan-88	4.3	G-9	failure of back pressure while G-9 damper being repaired	Forced
2	05-Jan-88	66.3	G-7	high combustion (flame) spread in burner unit	Planned
3	11-Jan-88	0.7	G-10	loose connection in Speedtronic control panel	Forced
4	21-Jan-88	89.8	G-9	combustion inspection	Planned
5	25-Jan-88	1.0	G-7	combustion problems due to decreased load	Forced
6	30-Jan-88	77.3	G-9	high combustion (flame) spread in burner unit	Planned
7	03-Feb-88	18.7	G-7	inspection of bypass damper	Planned
8	05-Feb-88	0.5	G-8	failure of control circuitry	Planned
9	06-Feb-88	34.9	G-8	tripped due to relay circuitry problems	Forced
10	08-Feb-88	0.5	G-8	excessive exhaust temperature	Planned
11	09-Feb-88	162.3	G-10	GE inspection	Planned
12	15-Feb-88	5.2	G-8	excessive exhaust pressure/damper problems	Planned
13	17-Feb-88	42.8	G-7	damper setup problems/HRSG controls adjustment	Planned
14	03-Mar-88	70.8	G-7	replace compressor water to renew with detergent	Planned
15	06-Mar-88	1.5	G-7	high combustion (flame) spread in burner unit	Forced
16	07-Mar-88	187.8	G-7	high combustion (flame) spread in burner unit	Forced
17	14-Mar-88	14.6	G-7	excessive vibration observed on bearing No. 2 and 3.	Forced
18	15-Mar-88	1.0	G-7	excessive exhaust temperature	Forced
19	16-Mar-88	545.8	G-7	excessive vibration observed on bearing No. 2 and 3.	Forced
20	22-Mar-88	0.6	G-8	excessive exhaust temperature	Forced
21	24-Mar-88	1.3	G-10	malfunctioning of limit switch	Forced
22	24-Mar-88	95.8	G-9	failure of limit switch on damper controls	Forced
23	28-Mar-88	0.7	G-10	turbine back pressure problems	Forced
24	31-Mar-88	156.1	G-8	combustion spread problem, and excessive vibration at 75 MW	Forced
25	13-Apr-88	78.7	G-9	excessive combustion spread led unit to run on reduced load	Forced
26	15-Apr-8[illegible]	10.3	G-7	sudden variation in system frequency.	Forced
27	25-Apr-88	339.1	G-8	failure of torque converter/over heating	Forced
28	04-May-88	15.4	G-7	abnormal sound and excess vibration	Forced
29	10-May-88	9.8	G-8	performance testing	Planned
30	17-May-88	19.9	G-8	bypass damper seal leakage problems	Forced

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
31	21-May-88	18.5	G-9	heavy oil leakage from ratio valves	Forced
32	27-May-88	15.6	G-7	computer failure	Forced
33	03-Jun-88	4.4	G-7	excessive exhaust temperature	Forced
34	03-Jun-88	65.6	G-8	heavy oil leakage from ratio valves	Forced
35	05-Jun-88	20.7	G-7	gas leakage from drain valve.	Forced
37	14-Jun-88	0.7	G-9	combustion trouble	Forced
38	14-Jun-88	2.0	G-8	variation in system frequency	Forced
36	14-Jun-88	2.5	G-9	variation in system frequency	Forced
39	14-Jun-88	19.4	G-7	variation in system frequency	Forced
40	19-Jun-88	0.9	G-8	low gas pressure	Forced
41	20-Jun-88	0.9	G-10	failure of A.C.Aux. supply in power control section	Forced
43	24-Jun-88	1.7	G-8	combustion inspection	Planned
42	24-Jun-88	39.3	G-7	excessive exhaust temperature	Forced
44	02-Jul-88	93.1	G-8	combustion inspection	Planned
45	08-Jul-88	0.5	G-10	malfunction of Mari gas regulator	Forced
46	08-Jul-88	1.2	G-8	malfunction of Mari gas regulator	Forced
47	19-Jul-88	118.2	G-9	combustion failure	Forced
48	25-Jul-88	42.7	G-10	cleaning dirty strainer water liner	Planned
49	26-Jul-88	64.4	G-7	damaged bypass damper gear drive	Forced
50	30-Jul-88	46.6	G-7	damaged bypass damper gear drive	Forced
51	31-Jul-88	93.6	G-10	malfunction of Mari gas regulator	Forced
52	02-Aug-88	115.5	G-7	short circuiting in gas valve	Forced
53	14-Aug-88	384.7	G-10	trial run of steam unit G-6.	Planned
54	23-Aug-88	40.3	G-8	computer failure	Forced
55	26-Aug-88	17.2	G-8	computer failure	Forced
56	31-Aug-88	15.6	G-7	HRSG pump trip-under voltage	Forced
57	02-Sep-88	80.9	G-9	prepare unit for oil firing	Planned
58	29-Sep-88	0.7	G-9	oil leakage on bearing No. 2	Forced
59	29-Sep-88	5.4	G-8	flame detector circuit failure	Forced
60	02-Oct-88	1.2	G-7	decreasing load trip	Forced
61	02-Oct-88	373.0	G-7	modification on bypass damper	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
62	06-Oct-88	20.3	G-8	gas mixing station connection work	Planned
63	07-Oct-88	18.7	G-9	gas mixing station connection work	Planned
64	09-Oct-88	0.6	G-9	variation in gas fuel pressure	Forced
65	18-Oct-88	252.9	G-8	test sychns. condenser operation	Planned
66	29-Oct-88	0.2	G-8	test sychns. condenser operation	Planned
67	29-Oct-88	0.6	G-8	desynchronized due to relay circuit problems	Planned
70	30-Oct-88	0.8	G-8	desynchronized due to relay circuit problems	Planned
68	30-Oct-88	18.3	G-7	combustion trouble	Forced
69	30-Oct-88	251.5	G-9	test sychns. condenser operation	Planned
71	15-Nov-88	37.0	G-8	stopped on request by GE	Planned
73	19-Nov-88	3.9	G-9	unit stopped as per instr. of LDC Lahore.	Planned
72	19-Nov-88	146.6	G-7	computer failure switch problems	Planned
75	20-Nov-88	18.9	G-8	unit stopped as per instr. of LDC Lahore.	Planned
74	20-Nov-88	71.9	G-9	gas leakage from turbine gas manifold	Planned
76	21-Nov-88	44.5	G-8	failure of AC aux supply	Forced
77	23-Nov-88	18.9	G-8	unit stopped as per instr. of LDC Lahore	Planned
78	23-Nov-88	20.4	G-9	unit stopped as per instr. of LDC Lahore	Planned
79	24-Nov-88	44.9	G-9	unit stopped as per instr. of LDC Lahore	Planned
80	25-Nov-88	10.1	G-8	unit stopped as per instr. of LDC Lahore	Planned
81	26-Nov-88	12.7	G-8	unit stopped as per instr. of LDC Lahore	Planned
82	26-Nov-88	14.1	G-9	unit stopped as per instr. of LDC Lahore	Planned
83	27-Nov-88	53.6	G-9	unit stopped as per instr. of LDC Lahore	Planned
84	28-Nov-88	32.9	G-8	unit stopped as per instr. of LDC Lahore	Planned
85	30-Nov-88	32.8	G-8	removal of blanking plate from exhaust	Planned
87	02-Dec-88	9.8	G-6	G.E. to take cooling tower in service	Planned
86	02-Dec-88	10.3	G-5	G.E. to take cooling tower in service	Planned
88	05-Dec-88	5.0	G-9	unit stopped as per instr. of LDC Lahore	Planned
89	05-Dec-88	14.2	G-5	unit stopped as per instr. of LDC Lahore	Planned
91	05-Dec-88	15.4	G-8	unit stopped as per instr. of LDC Lahore	Planned
90	05-Dec-88	18.8	G-6	unit stopped as per instr. of LDC Lahore	Planned
92	08-Dec-88	1.4	G-6	tripped during the testing of vacum protection	Forced

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
94	08-Dec-88	5.9	G-8	unit stopped as per instr. of LDC Lahore	Planned
93	08-Dec-88	7.0	G-8	machine shut be G.E. to work bypass dampers	Planned
95	11-Dec-88	39.9	G-7	machine shut be G.E. to work on generator set	Planned
99	12-Dec-88	0.2	G-6	machine dsychrzd. to connect Sibi Line	Planned
98	12-Dec-88	0.3	G-6	machine dsychrzd. to disconnect Sibi Line	Planned
96	12-Dec-88	1.3	G-5	tripping of auxiliary breaker	Forced
97	12-Dec-88	1.3	G-5	loss of inlet pressure	Forced
100	13-Dec-88	1.1	G-9	machine shut be G.E. to work bypass dampers	Planned
101	13-Dec-88	106.4	G-6	machine stopped due to approved shutdown of G-9	Planned
102	18-Dec-88	1.3	G-6	transformer problems	Forced
103	19-Dec-88	1.6	G-5	low drum level in HRSG and caused HRSG to trip	Forced
104	21-Dec-88	83.7	G-7	D.C. ground fault on both the poles	Forced
105	28-Dec-88	3.0	G-5	tripped due to low servo fluid pressure	Forced
106	06-Jan-89	1.3	G-5	tripped due to sudden bypass closure	Forced
107	06-Jan-89	4.8	G-6	GE inspection of cooling towers	Planned
108	06-Jan-89	6.1	G-5	GE inspection of cooling towers	Planned
109	07-Jan-89	19.3	G-7	tripped due to IGV position trouble(compressor bled valve)	Forced
110	17-Jan-89	3.5	G-5	variation in system frequency	Forced
111	22-Jan-89	1.4	G-9	tripped due to servo trouble	Forced
112	22-Jan-89	3.6	G-6	machine stopped due to G-9 tripping	Planned
113	29-Jan-89	1398.3	G-7	vibration problem	Planned
115	01-Feb-89	1.2	G-8	loss of speedtronic panel supply	Forced
116	01-Feb-89	3.5	G-5	machine stopped on tripping G-8	Planned
114	01-Feb-89	4.7	G-8	tripped due to loss of speedtronic panel supply	Forced
117	01-Feb-89	8.0	G-5	machine stopped on tripping G-8	Planned
118	13-Feb-89	3.2	G-5	tripped due to false signal of low lube oil level	Forced
119	18-Feb-89	2.3	G-5	tripped due to boiler drum high level protection	Forced
120	19-Feb-89	1.9	G-6	tripped due to loss of vacum as C.M pump tripped	Forced
121	19-Feb-89	51.7	G-5	tripped due to loss of vacum	Forced
122	26-Feb-89	3.0	G-5	tripped I/O controller i.e process control	Forced
123	01-Mar-89	27.9	G-6	work on gearbox of bypass damper	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
124	04-Mar-89	0.5	G-9	low gas fuel pressure	Forced
125	04-Mar-89	1.5	G-8	low gas pressure	Forced
126	04-Mar-89	2.1	G-6	tripping of G-9 on lo gas fuel pressure	Forced
127	08-Mar-89	0.9	G-5	tripped due to low vacum level in condenser	Forced
128	08-Mar-89	3.6	G-5	upper/lower governor servo valves not responding equally	Forced
129	09-Mar-89	2.4	G-5	variation in system frequency	Forced
130	11-Mar-89	1.9	G-5	tripped due to feedwater loss	Forced
131	11-Mar-89	17.4	G-8	vibration problem	Planned
132	11-Mar-89	20.6	G-5	desynchroninized to stop G-8 on approved shutdown	Planned
133	19-Mar-89	0.6	G-9	variation in pressure of gas turbine heater	Forced
134	19-Mar-89	1.9	G-6	tripping of G-9 on lo gas fuel pressure	Forced
135	19-Mar-89	51.9	G-5	due to low flow thru evaporator	Forced
137	20-Mar-89	9.0	G-9	loss of flame	Forced
136	20-Mar-89	13.3	G-6	tripped manually by G-9 on loss of flame	Forced
139	22-Mar-89	1.0	G-9	excessive vibration on bearing No. 3	Planned
138	22-Mar-89	2.6	G-6	stopped due to G-9 shutdown	Planned
140	23-Mar-89	130.1	G-9	tripped due to combustion trouble	Forced
141	23-Mar-89	156.3	G-6	G-9 tripping plus combustion trouble	Planned
143	29-Mar-89	0.8	G-9	low gas fuel pressure	Forced
142	29-Mar-89	5.7	G-9	tripped due to combustion trouble	Forced
144	30-Mar-89	4.3	G-6	loss of feedwater discharge pressure	Forced
145	31-Mar-89	102.8	G-7	work on gear box unit	Planned
146	01-Apr-89	0.6	G-5	steam inlet pressure high	Forced
147	01-Apr-89	2.3	G-5	failure of process controllers	Forced
148	02-Apr-89	1.0	G-5	failure of process controllers	Forced
149	05-Apr-89	4.2	G-8	tripped due to high exhaust pressure	Forced
150	05-Apr-89	4.2	G-5	variation in system frequency	Forced
151	05-Apr-89	54.3	G-9	replace modified gear box	Planned
152	05-Apr-89	60.9	G-5	approved shutdown of G-9	Planned
153	06-Apr-89	1.1	G-6	computer failure	Forced
154	06-Apr-89	1.4	G-5	electronic circuitry failure	Forced

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
155	07-Apr-89	0.9	G-5	steam cycle trip	Forced
156	08-Apr-89	25.3	G-7	tripped due to grounding of II Pole	Forced
158	13-Apr-89	2.0	G-5	inspection, lead rejection test	Planned
157	13-Apr-89	41.2	G-7	work on exhaust duct	Planned
159	14-Apr-89	0.4	G-5	inspection, lead rejection test	Forced
160	14-Apr-89	1.7	G-6	performance testing	Planned
162	29-Apr-89	0.7	G-5	wiring error during dynamic test	Forced
161	29-Apr-89	1.1	G-5	wiring error during dynamic test	Forced
163	04-May-89	5.7	G-5	tripping of G-8 on low gas	Forced
164	05-May-89	12.4	G-6	inspection of condenser hot well	Planned
165	06-May-89	2.6	G-6	steam cycle trip	Forced
166	08-May-89	8.3	G-6	controller circuit failure	Planned
167	09-May-89	37.3	G-7	short circuit of servo/governor	Forced
169	10-May-89	1.6	G-8	variation in gas fuel pressure	Forced
168	10-May-89	3.1	G-5	variation in gas fuel pressure	Forced
170	18-May-89	1.4	G-5	failure of inlet pressure controller	Forced
171	19-May-89	1.5	G-5	variation in system frequency	Forced
172	20-May-89	1.1	G-9	variation in system frequency	Forced
173	20-May-89	1.2	G-6	variation in system frequency	Forced
175	20-May-89	1.5	G-5	variation in system frequency	Forced
176	20-May-89	21.8	G-6	variation in gas pressure	Forced
174	20-May-89	27.7	G-5	variation in system frequency	Forced
177	21-May-89	3.8	G-5	problems due to high differential pressure	Forced
178	22-May-89	3.1	G-6	feed water pressure loss	Forced
179	29-May-89	1.6	G-5	controller failure	Forced
180	03-Jun-89	0.9	G-5	high level on HRSG 1A	Forced
181	06-Jun-89	4.8	G-7	transfer of gas to HSD diesel fuel switch problems	Planned
182	09-Jun-89	4.4	G-5	tripping of Aux supply breaker	Forced
183	14-Jun-89	5.6	G-5	low exhaust vacum on condensor	Forced
184	22-Jun-89	1.5	G-5	low exhaust vacum on condensor	Forced
186	28-Jun-89	1.4	G-7	tripping of south bus bar no.1	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
185	28-Jun-89	2.4	G-6	tripping of Aux supply breaker	Forced
187	01-Jul-89	120.1	G-10	unit transfer problems	Planned
188	06-Jul-89	57.9	G-10	differential pressure to low	Forced
189	07-Jul-89	43.4	G-7	leakage problems on Sui gas pipeline	Planned
190	10-Jul-89	6.9	G-8	inspection of exhaust duct	Planned
191	11-Jul-89	1.4	G-6	inlet pressure controller failure	Forced
192	12-Jul-89	1.9	G-6	malfunctioning of main steam valve on HRSG 2A	Forced
193	12-Jul-89	4.8	G-10	damper cycle failure	Forced
194	15-Jul-89	28.8	G-8	variation of gas header pressure	Planned
195	18-Jul-89	0.3	G-8	checking auto changeover of Aux supply	Planned
196	21-Jul-89	3.2	G-7	malfunction of controller	Forced
197	22-Jul-89	2.3	G-6	malfunctioning of main steam valve on HRSG 2A	Forced
198	30-Jul-89	19.2	G-8	work on bypass damper	Planned
201	31-Jul-89	0.6	G-10	low fuel gas fuel pressure	Forced
200	31-Jul-89	1.5	G-9	low fuel gas fuel pressure	Forced
199	31-Jul-89	2.3	G-6	low fuel gas fuel pressure	Forced
203	01-Aug-89	0.6	G-9	low fuel gas fuel pressure	Forced
205	01-Aug-89	0.9	G-8	low fuel gas fuel pressure	Forced
202	01-Aug-89	1.2	G-10	low fuel gas fuel pressure	Forced
204	01-Aug-89	5.2	G-6	steam cycle trip	Forced
206	01-Aug-89	13.7	G-5	low flowrate thru evaporator	Forced
207	08-Aug-89	0.8	G-8	excessive exhaust pressure on damper	Forced
209	08-Aug-89	18.8	G-8	bypass damper modifications	Planned
208	08-Aug-89	133.2	G-5	heavy leakage from circulating pump	Planned
211	09-Aug-89	4.5	G-6	cooling tower coming on-line	Planned
210	09-Aug-89	10.9	G-6	malfunctioning IPC controller	Forced
212	14-Aug-89	5.8	G-5	tripping of auxilliary breaker	Forced
214	15-Aug-89	24.7	G-6	failure of load rejection test	Forced
213	15-Aug-89	396.3	G-5	first GE inspection	Forced
215	19-Aug-89	1.5	G-7	failure of AC supply	Forced
216	01-Sep-89	720.0	G-5	first GE inspection	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
217	07-Sep-89	0.8	G-6	steam cycle trip	Forced
218	07-Sep-89	0.9	G-6	steam cycle trip	Forced
219	18-Sep-89	12.1	G-10	bypass damper modifications	Planned
221	19-Sep-89	1.0	G-10	exciter system trouble	Forced
220	19-Sep-89	2.6	G-6	loss of vacum	Forced
223	21-Sep-89	1.7	G-6	auto synchronous operation by GE	Planned
222	21-Sep-89	1.8	G-6	low feed water pressure	Forced
224	21-Sep-89	156.9	G-7	Trpd. due to flr. of AC sply. for cptr.	Planned
225	28-Sep-89	61.3	G-6	combustion inspection	Planned
226	29-Sep-89	1.4	G-8	exhaust trouble and failurte of flame	Forced
227	29-Sep-89	9.6	G-10	bypass damper modification work	Planned
228	30-Sep-89	0.9	G-6	inlet pressure controller failure	Forced
229	01-Oct-89	678.0	G-5	first GE inspection	Planned
230	02-Oct-89	1.8	G-10	reason for tripping unknown	Forced
231	02-Oct-89	3.9	G-6	cooling water piping work	Planned
232	08-Oct-89	0.2	G-10	testing of auto change over of aux. supply	Forced
233	08-Oct-89	8.2	G-10	bypass damper modification work	Planned
235	13-Oct-89	0.6	G-10	false indication	Forced
234	13-Oct-89	2.8	G-6	aux. supply problems	Forced
237	13-Oct-89	21.7	G-6	hydrogen leakage from generator	Planned
236	13-Oct-89	193.8	G-10	heavy oil leakage from both sides of generator set	Planned
238	15-Oct-89	13.6	G-6	low feed water	Forced
239	18-Oct-89	1.3	G-7	smoke from battery room	Planned
240	18-Oct-89	38.9	G-7	combustion inspection	Planned
243	22-Oct-89	2.9	G-10	atmospheric air particles trouble – dust	Planned
241	22-Oct-89	3.7	G-7	tripping indicator problems	Forced
242	22-Oct-89	46.6	G-10	vibration related maintenence	Planned
244	23-Oct-89	4.7	G-6	problem in pressure switch	Forced
245	28-Oct-89	74.1	G-6	first inspection	Planned
246	29-Oct-89	46.2	G-5	inspection of indicator switches	Planned
247	30-Oct-89	136.9	G-9	boiler inspection	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
250	31-Oct-89	1.2	G-5	inspection for auto operation	Planned
248	31-Oct-89	1.3	G-5	malfunctioning of IPC	Forced
249	31-Oct-89	2.3	G-5	vacuum test failure	Forced
251	01-Nov-89	2.0	G-5	vacuum test failure	Forced
252	01-Nov-89	5.1	G-7	tripped due to unknown reasons	Forced
253	01-Nov-89	687.3	G-6	first inspection	Planned
254	03-Nov-89	1.2	G-5	servo pump failure	Forced
255	03-Nov-89	41.4	G-5	excitation problem	Forced
258	04-Nov-89	4.3	G-8	stopped due to load dispatch center request	Planned
259	04-Nov-89	14.0	G-10	stopped due to load dispatch center request	Planned
256	04-Nov-89	16.5	G-8	stopped due to load dispatch center request	Planned
257	04-Nov-89	16.9	G-7	stopped due to load dispatch center request	Planned
261	06-Nov-89	0.5	G-5	load rejection test failure	Forced
260	06-Nov-89	1.0	G-5	tripped during testing of vacuum unloading	Forced
262	07-Nov-89	1.7	G-5	tripped during testing of vacuum unloading	Forced
263	07-Nov-89	2.8	G-5	load rejection test failure	Forced
264	08-Nov-89	10.8	G-5	high differential expansion	Forced
265	08-Nov-89	16.4	G-9	stopped due to load dispatch center	Planned
266	09-Nov-89	6.4	G-5	steam turb. control system failure	Forced
267	09-Nov-89	94.6	G-5	load rejection test failure	Forced
268	10-Nov-89	1.7	G-7	tripped due to unknown reasons	Forced
269	10-Nov-89	33.6	G-8	stopped due to load dispatch center request	Planned
270	11-Nov-89	14.6	G-10	stopped due to heavy vibration on pump motor	Planned
271	12-Nov-89	178.1	G-10	stopped due to heavy vibration on pump motor	Planned
273	13-Nov-89	1.0	G-7	compressor blade vibration	Forced
272	13-Nov-89	2.3	G-7	compressor blade vibration	Forced
274	14-Nov-89	1.1	G-5	fire observed at turbine bearing No. 1	Forced
275	14-Nov-89	194.8	G-5	fire observed at turbine bearing No. 1	Forced
276	15-Nov-89	6.3	G-7	tripped due to unknown reasons	Forced
277	19-Nov-89	202.8	G-7	stopped due to load dispatch center request	Planned
278	20-Nov-89	1.1	G-8	malfunctioning Mari gas regulator	Forced

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
279	21-Nov-89	32.0	G-10	servo trouble	Planned
280	22-Nov-89	5.7	G-10	temperature control trouble	Forced
281	23-Nov-89	7.6	G-8	malfunctioning Mari gas regulator	Forced
282	23-Nov-89	21.8	G-5	tripping of G-8	Forced
283	27-Nov-89	10.1	G-5	malfunctioning of turbine control valve	Forced
284	28-Nov-89	1.2	G-8	false indication on turbine and generator controller	Forced
285	28-Nov-89	3.0	G-5	tripping of G-8/ HRSG 1A shutdown	Planned
286	29-Nov-89	16.7	G-10	inlet guide vane trouble	Forced
288	30-Nov-89	9.4	G-6	inspection for inadequate discharge pressure	Planned
287	30-Nov-89	33.0	G-5	high level of drum on HRSG 1B	Forced
289	01-Dec-89	24.4	G-6	GE testing	Planned
290	02-Dec-89	6.4	G-6	failure of spped relays	Forced
291	04-Dec-89	0.9	G-6	low flow through evaporator	Forced
292	04-Dec-89	1.1	G-6	vacum test failure	Forced
293	04-Dec-89	18.7	G-6	inspection to check feed pump discharge pressure	Planned
295	08-Dec-89	0.8	G-6	low flow through evaporator	Forced
294	08-Dec-89	0.9	G-5	high level of drum on HRSG 1B	Forced
296	09-Dec-89	5.3	G-6	vacum test failure	Forced
297	11-Dec-89	8.5	G-10	compressor blade problems	Forced
298	11-Dec-89	18.2	G-5	vacum unloading problems	Forced
299	12-Dec-89	7.2	G-6	low flow through evaporator	Forced
300	12-Dec-89	15.2	G-5	stopped due to load dispatch center request	Planned
302	13-Dec-89	11.5	G-10	stopped due to load dispatch center request	Planned
301	13-Dec-89	13.5	G-9	inspection/ work on isolation damper	Planned
304	14-Dec-89	0.6	G-5	excessive exhaust temperature	Forced
306	14-Dec-89	0.6	G-10	malfunctioning of Micon at gas mixing station	Forced
305	14-Dec-89	1.3	G-8	malfunctioning of Micon at gas mixing station	Forced
303	14-Dec-89	3.9	G-6	G-10 tripped	Forced
307	14-Dec-89	5.9	G-5	GE inspection of vibration problems	Planned
308	15-Dec-89	4.1	G-5	generator diffrential problems	Forced
310	15-Dec-89	7.9	G-5	generator diffrential problems	Planned

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
309	15-Dec-89	13.2	G-10	inlet guide vane trouble	Forced
311	16-Dec-89	2.4	G-10	servo position trouble	Planned
312	17-Dec-89	88.0	G-10	replacing oil and fixing servo panel	Forced
313	23-Dec-89	4.3	G-10	inlet guide vane trouble	Forced
315	24-Dec-89	2.2	G-10	combustion trouble	Forced
314	24-Dec-89	2.2	G-5	HRSG 1B circ. pump and steam turbine trip	Forced
316	27-Dec-89	1.5	G-5	circ. pump No.2 of HRSG 1B and 1A tripped	Forced
317	31-Dec-89	1.6	G-5	steam and gas turbine trip	Forced
331	01-Jan-90	4.1	G-10	excessive exhaust temperature	Forced
329	03-Jan-90	0.7	G-9	isolation damper problems	Forced
332	03-Jan-90	1.0	G-10	low gas fuel pressure	Forced
328	03-Jan-90	1.1	G-8	low gas fuel pressure	Forced
326	03-Jan-90	2.4	G-7	malfunctioning of Micon at gas mixing station	Forced
318	03-Jan-90	2.8	G-5	malfunctioning of Micon at gas mixing station	Forced
321	03-Jan-90	3.3	G-6	malfunctioning of Micon at gas mixing station	Forced
333	04-Jan-90	1.2	G-10	combustion spread problems	Planned
319	12-Jan-90	1.8	G-5	steam cycle due to unit aux. breaker	Forced
323	14-Jan-90	1.5	G-6	malfunctioning of Micon at gas mixing station	Forced
322	14-Jan-90	2.5	G-6	steam cycle trip due to feedwater loss	Forced
324	15-Jan-90	1.2	G-6	steam cycle trip due to feedwater loss	Forced
334	19-Jan-90	2.0	G-10	stopped to reset computer	Planned
335	23-Jan-90	0.8	G-10	Stpd. in emgy. shtdn. apvd. by LDC	Planned
327	26-Jan-90	1.5	G-7	compressor blade valve inlet guide vane trouble	Forced
325	27-Jan-90	4.7	G-6	heavy variation in system frequency	Forced
320	27-Jan-90	5.5	G-5	heavy variation in system frequency	Forced
330	28-Jan-90	16.0	G-9	inspection of HRSG leakage problems	Planned
343	01-Feb-90	6.1	G-7	inspection and checking high temperature combust. spread	Planned
339	02-Feb-90	1.2	G-6	steam cycle trip	Forced
340	04-Feb-90	0.7	G-6	high frequency variation seen on system	Forced
336	08-Feb-90	1.5	G-5	frequency variation	Forced
341	08-Feb-90	2.3	G-6	high frequency variation seen on system	Forced

APPENDIX A. Guddu: Planned and Forced Outages Report for the Period January 1988 to February 1990

No.	Date	Outage (hrs)	Gen. No.	Reason of Outages	Type
344	15-Feb-90	0.7	G-7	tripped due to unknown reasons	Forced
337	15-Feb-90	1.3	G-5	low flow of evaporator	Forced
346	15-Feb-90	25.2	G-10	inspection and cleaning fuel nozzles	Planned
338	18-Feb-90	2.6	G-5	variation in system frequency	Forced
347	18-Feb-90	2.9	G-10	compressor blade valve inlet guide vane trouble	Forced
342	18-Feb-90	3.3	G-6	steam cycle trip	Forced
348	20-Feb-90	8.4	G-10	rupture of hydraulic line	Planned
349	22-Feb-90	11.3	G-10	cooling water system problems	Forced
345	23-Feb-90	31.4	G-8	excessive vibration	Planned
351	25-Feb-90	0.8	G-10	combustion spread trouble	Forced
350	25-Feb-90	3.3	G-10	rupture of hydraulic oil line	Forced
352	27-Feb-90	1.9	G-10	heavy leakage in control oil line	Planned

APPENDIX B
Guddu Plant Performance Curves

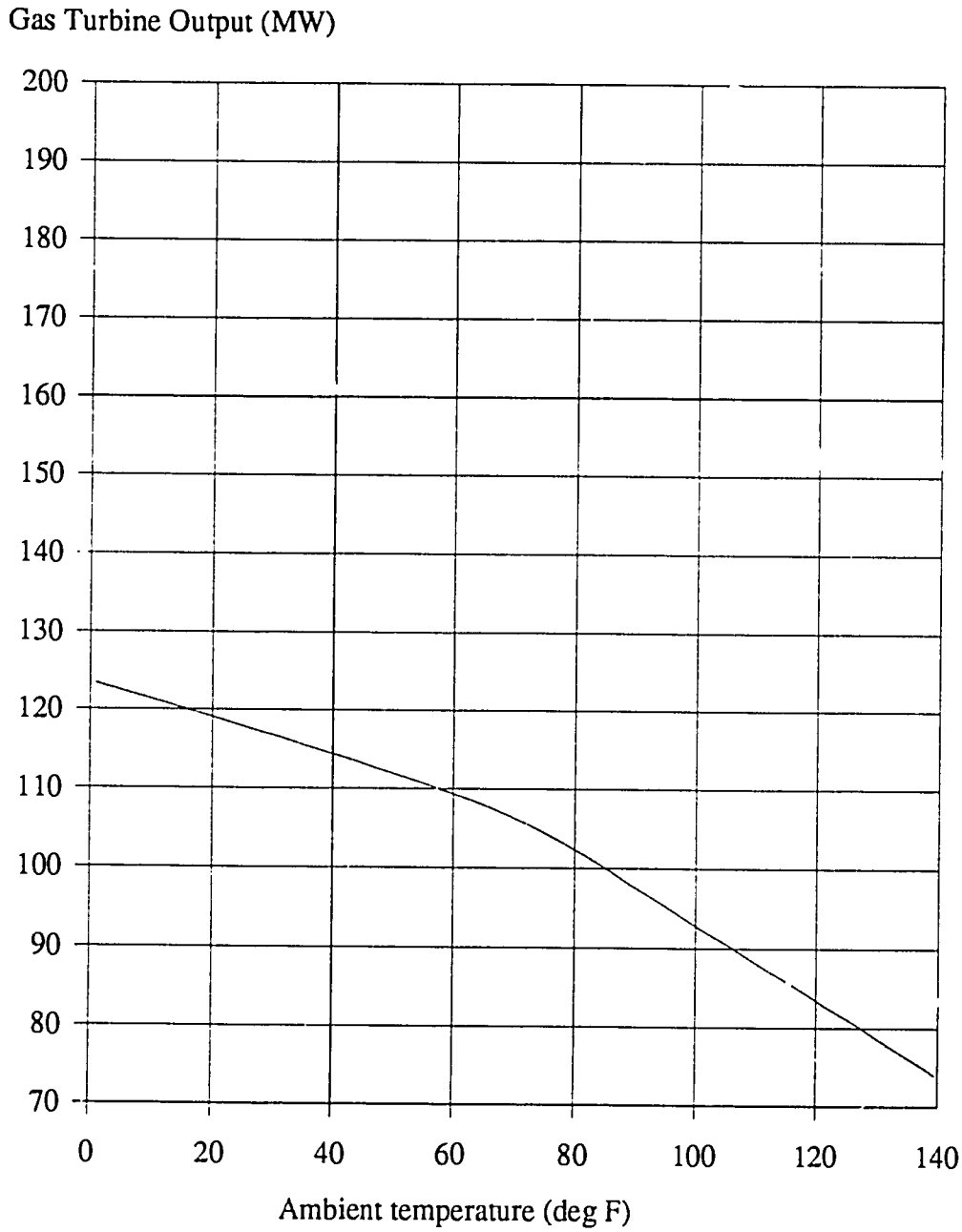


Figure 1. Gas Turbine - Effect of Compressor Inlet Ambient Temperature on Maximum Output

Source: Water and Power Development of Pakistan (WAPDA),April 1990

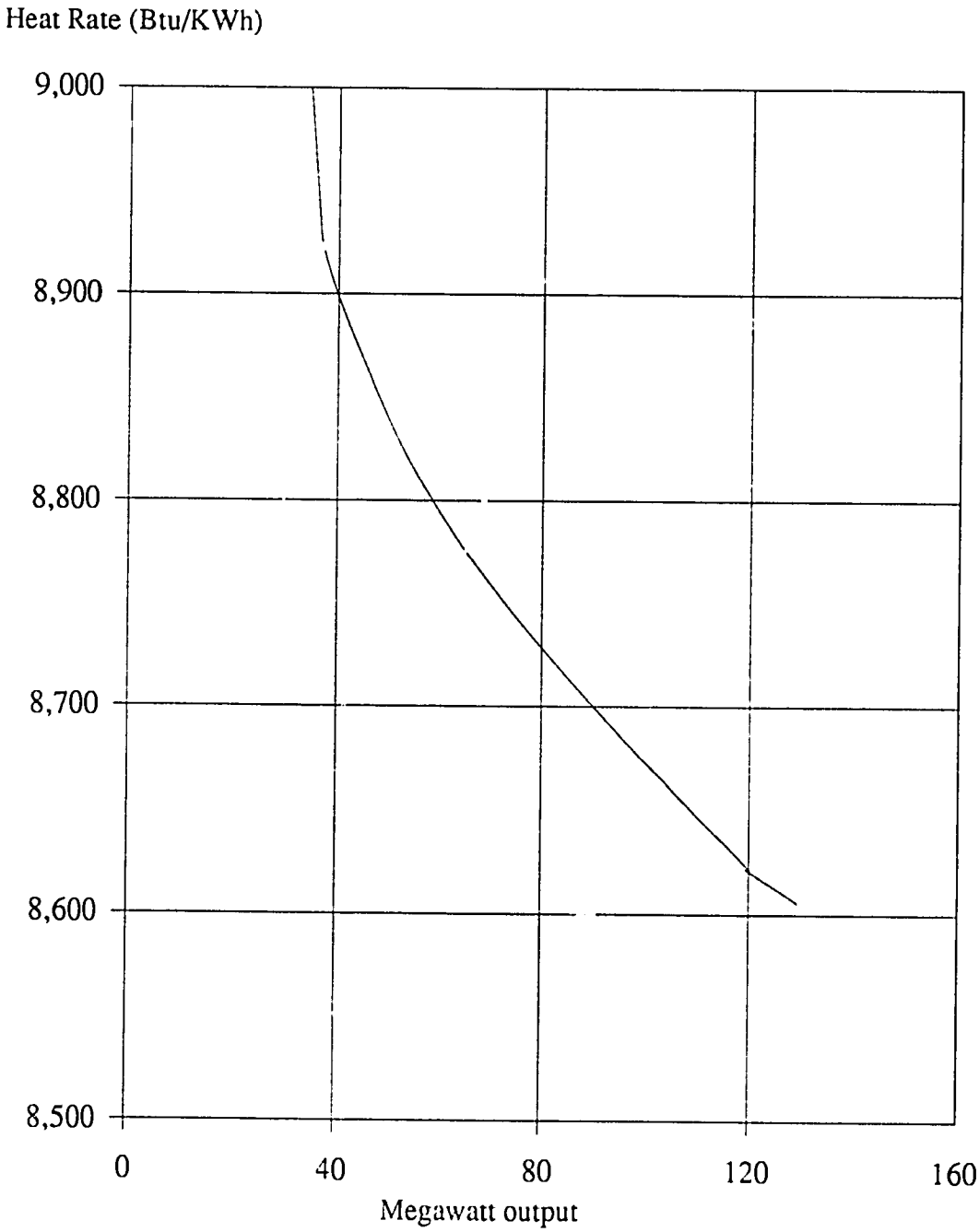


Figure 2. Heat Rate as a Function of Output

Note: The performance curve assumes that 2/3 of the total output is derived from a single gas turbine and 1/3 is derived from the steam turbine.

Source: Water and Power Development Authority of Pakistan (WAPDA), April 1990

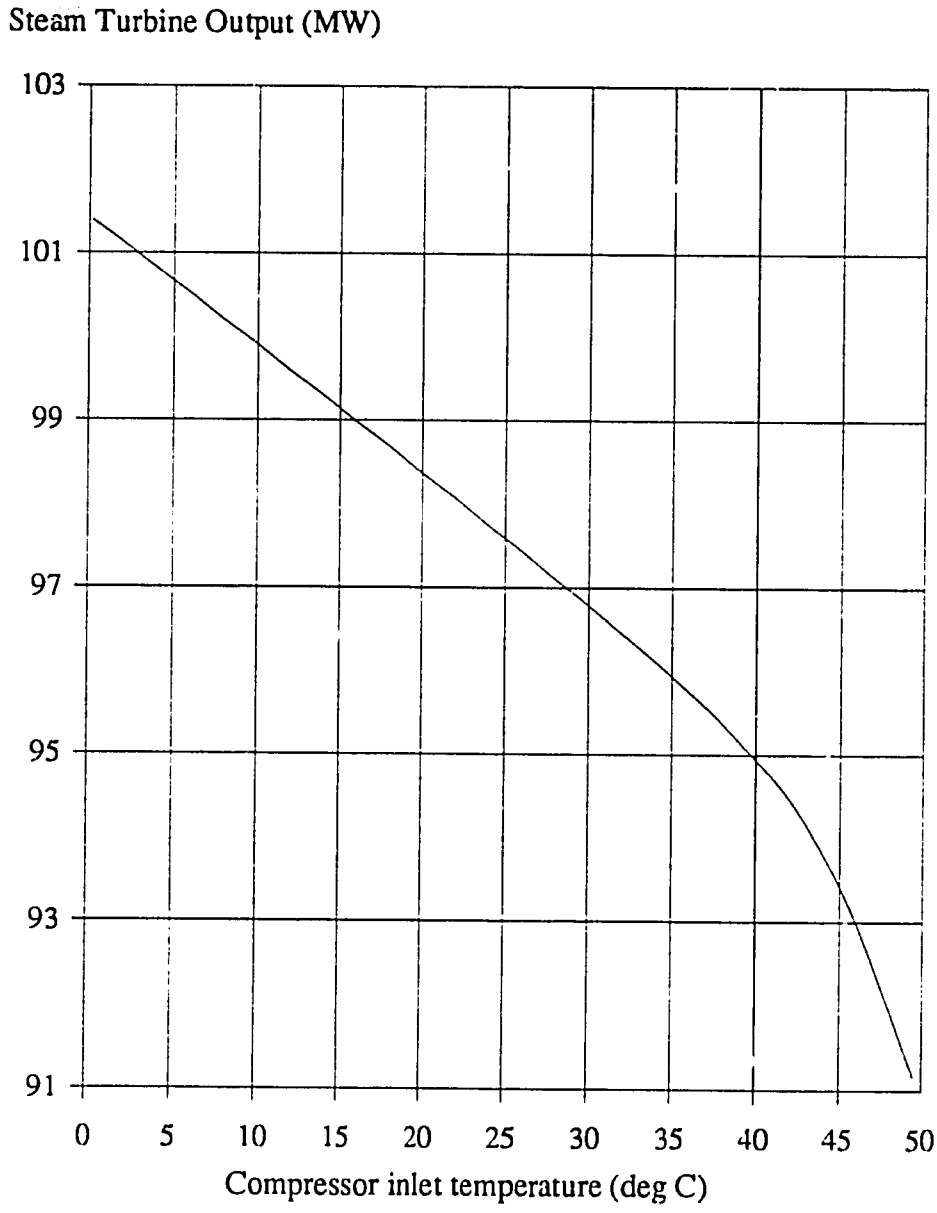


Figure 3. Steam Turbine Output Versus Compressor Inlet Ambient Temperature

Source: Water and Power Development Authority of Pakistan (WAPDA), April 1990

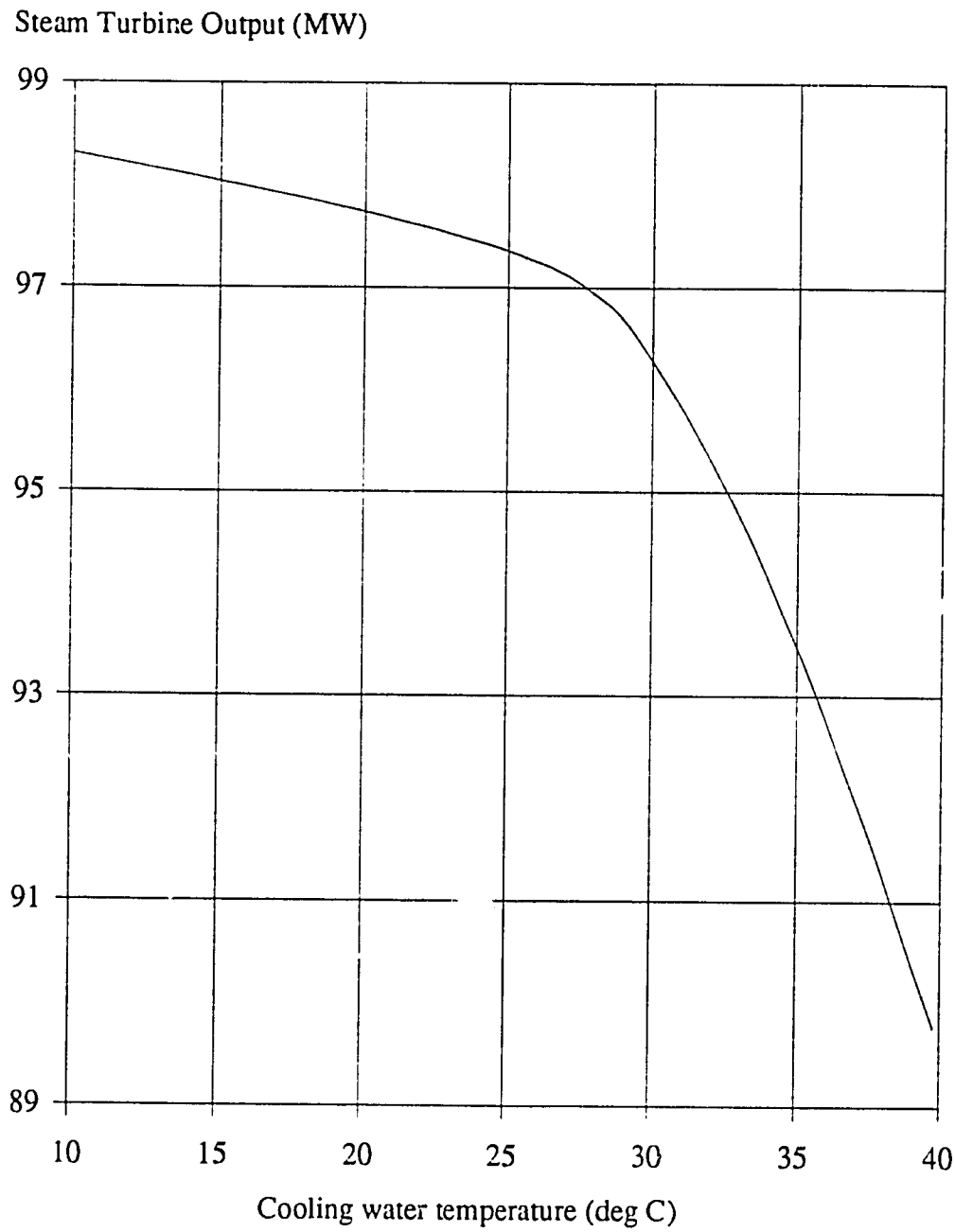


Figure 4. Steam Turbine Output Versus Cooling Water Temperature

Source: Water and Power Development of Pakistan (WAPDA), April 1990

APPENDIX C

Talkha Plant Operations

PLANT OPERATION

I. INTRODUCTION

The General Electric STAG 400 Combined Cycle Power Plant consists of four gas turbine generator units and the major equipment making up the steam cycle. The major steam cycle equipment includes the heat recovery steam generators (HRSG's), the steam turbine-generator, and the mechanical auxiliary equipment. The start-up and on-line control systems and the integrated protective system is included to support the General Electric supplied power generation equipment.

The resulting plant is operated from a central control room. One plant operator is required in the control room. The support of one roving operator is recommended.

In daily operation the plant may be started and brought to full base load in less than one hour with approximately 65 percent of power available in 15 to 20 minutes. The GE design permits operation at partial loads while maintaining favorable heat rates since one or more of the gas turbines may be shutdown. The gas turbines are equipped with variable inlet guide vanes which improves the part load heat rate and minimizes steam temperature decrease as load is reduced.

A plant protective system is included which protects individual units of major equipment and limits the propagation of fault conditions to other areas of the plant. Impending trouble is detected and alarmed to permit the plant operator to take corrective action to restore the equipment to normal operation. Automatic action is incorporated to place equipment in a safe condition when there is little or no time for operator action.

The following pages of this section describes the operation of the plant during start-up, normal operation, shutdown, and emergency conditions.

II. GENERAL OPERATION

The [illegible] input to the combined cycle is the [illegible] by the gas turbines. The steam cycle of the STAG system utilizes the energy available from the exhaust of the gas turbines. Gas turbine exhaust is ducted to the heat recovery steam generators (HRSG's).

Steam generated by the HRSG's enters a common header and furnishes steam to the steam turbine-generator. The output of the steam turbine-generator varies with the fuel flow and output of the gas turbines.

For ease of start-up, shutdown, and flexibility of operation, means are provided to isolate the gas turbine from the steam cycle equipment. This is accomplished by an exhaust bypass system. This system consists of an exhaust bypass stack, an isolation damper, and a bypass damper. The dampers are used in full open, full closed mode for simple cycle (bypass damper open, isolation damper closed) or combined cycle (bypass damper closed, isolation damper open) operation. The dampers are modulated during start-up to control the rate of heat input into the steam cycle equipment.

Each HRSG unit incorporates four heat transfer sections as shown in Flow Diagram 11U5415-M200. These are the superheater, evaporator, economizer sections and the deaerator evaporator sections. Each HRSG incorporates a transfer pump to pump feedwater from the deaerator to the HP economizer. The deaerator heats and deaerates the feedwater using energy recovered from the exhaust gas.

The steam generated by individual HRSG's discharges into a common header through separate non-return and isolation shutoff valves. The water level in the HRSG drum is maintained within normal operating limits by modulation of individual feedwater control valves using a conventional three-element control for running conditions and a single-element control for start-up.

Condensate pumps provide low pressure condensate flow to deaerator sections. These pumps take suction from the condenser hotwell. Shutoff valves isolate flow to out-of-service HRSG's. Water level in the deaerator storage tank is maintained within normal limits by regulating flow from the condensate pump with a single element level control system.

The steam turbine operates with sliding steam pressure with the control valves maintained 95% open during most operation under load. The pressure varies as a function of the steam flow. Steam flow is determined by the number of gas turbines and HRSG's in operation and the gas turbine load. If an event causes a step function in steam flow, the control system will [illegible] the steam turbine control valve to maintain the pressure [illegible] the evaporator to the upset. The valve will then be ramped to [illegible] position at a rate satisfactory to the HRSG's.

III. PLANT LOAD RANGE

The STAG combined cycle power plant may be configured in a variety of ways to meet load demands. The generation equipment may be operated in the simple cycle mode or in the combined cycle mode.

The STAG plant is in the simple cycle mode when the gas turbines are operated with the exhaust gas bypassing the HRSG's. Each gas turbine may be operated at either the spinning reserve, part load, or base load points.

The STAG plant is in the combined cycle mode when the steam cycle equipment is placed in service. The isolation dampers between the operating gas turbines and the HRSG's are fully open and the bypass dampers are fully closed. The steam turbine-generator is synchronized and produces power in proportion to the steam generated by the HRSG's.

Figure 1 illustrates the relationships between heat rate and output for a typical STAG plant operating in the combined cycle mode. Each curve of Figure 1 relates to a specific number of gas turbines operating fully coupled to the HRSG's. The plant heat rate is reduced and the efficiency increased as the gas turbine load is raised. The locus of low steam temperature (TSL) defines the plant load range below which gas turbine exhaust gas temperature is so low that the steam has insufficient superheat resulting in condensation of excessive moisture in the steam turbine low pressure stages. Normally the STAG plant is operated well away from the locus of TSL and low steam temperature conditions do not impose significant constraints on operation. The curves of Figure 1 indicate the operating points at which the gas turbine inlet guide vanes (IGV's) modulate to maintain exhaust temperature near rated temperature.

The plant operator should consider both the economic advantages of operating at high plant efficiencies and the time required to start and load additional equipment prior to reconfiguring the plant to meet changing demand situations.

IV. PLANT STARTUP, SHUTDOWN, AND ON-LINE CHANGES

A. General

The STAG combined cycle plant control system is designed for convenient startup, synchronization, and loading of the plant equipment with a minimum number of control room operators.

The various units of plant equipment are made ready to start remote manually by the operator in the control room. The gas turbine startup occurs independently of the steam cycle equipment. When the plant is operated in the simple cycle mode, the selected gas turbine equipment need only be in a state of readiness prior to a simple cycle plant start.

The condition affecting the time for combined cycle plant startup is steam turbine temperature. Turbine shell temperatures are measured and used as the criterion to establish startup and loading rates throughout the steam cycle equipment. Following an overnight shutdown (12 hours or less), the steam turbine will remain hot and the HRSG's will remain pressurized. Hot start plant conditions allow the fastest startup times. Figure 2 shows that a typical hot start can be achieved in approximately 60 minutes. Following a longer shutdown period, such as a weekend (72 hours or less), the steam turbine will cool further and the HRSG's will lose pressurization. The result will be a lengthier plant startup time. Longer startup times result when the system is totally cold.

Some units of plant equipment may be in varying states of readiness for plant start. These will require certain operator action prior to initiating a plant start. The mechanical auxiliary equipment, for example, must be placed in service and closed loop controls should be stabilized in the automatic mode.

B. Gas Turbine Startup Features

Gas turbine starting is staggered by 30-second intervals to limit in-rush loads on the auxiliary power system. Under SPEEDTRONIC™ sequenced startup, each gas turbine, in turn, will accelerate to firing speed and hold for a brief preselected time for gas path purging. After purging and the flame has been established, the gas turbine will maintain a reduced speed for a short warmup period.

The gas turbine will then automatically accelerate at a controlled rate to rated speed, synchronize, and load at a controlled rate to base load. This procedure results in full gas turbine output in approximately 15 to 20 minutes after initiation of startup. The gas turbines contribute approximately 65 percent of rated plant capability when all units are operating at base load.

C. Steam Cycle Startup Features

Startup of the steam cycle system consists of programmed events that must be performed to maintain coordinated management of the integrated steam cycle equipment during warmup and loading. The major elements used for startup of the steam cycle system are as follows:

1. The HRSG System (multiple units)
2. The Steam Turbine and Bypass System
3. The Steam Cycle Auxiliary System
4. The Plant Level Controls

Individual HRSG startup will occur when selected gas turbine permissive signals exist within the respective HRSG controls, i.e., gas turbine warmup complete or gas turbine generator breaker closed. When the required conditions are satisfied, each HRSG will be started by opening the HRSG drains to allow adequate water removal prior to admitting steam into the header, and then admitting heat into the HRSG by opening the exhaust gas path isolation dampers. The superheater vent is opened as the HRSG becomes pressurized and recloses at approximately 50 psig.

Steam system starting time is the aggregate of the time required for warmup of the HRSG, the steam header, the steam turbine rotor and casing, and the time for accelerating and loading the steam turbine. The steam turbine has the longest thermal time constant within the steam cycle system, so turbine metal temperatures are measured prior to startup and used to establish the startup and loading program for the overall steam system.

The first HRSG started will provide steam for the initial steam cycle warmup and for starting and initial loading of the steam turbine. All other HRSG units selected to start will proceed to the simmer mode and will hold until the steam cycle is ready to accept more steam. Each subsequent HRSG unit, while holding in the simmer mode, will admit a small amount of steam flow into the header. This will synchronize the HRSG pressure with the header pressure, and will establish the HRSG as ready to increase steam flow with minimum delay when the remaining steam cycle system is ready to accept it.

The motor-operated shutoff valves at the HRSG superheater outlet should be opened early in the startup program for the first unit to start, and the steam header drains should be placed in service to assure that all steam line condensate is properly blown out. The steam turbine stop valve should also be opened early in the startup program to warm the steam line up to the steam control valve(s). Warmup steam flow will be induced through the steam turbine by opening the steam turbine casing drains.

Initial warming of the header and turbine steam control valve inlet is executed by scheduling the rate of pressure rise within the system, and thus the rate of change of saturation temperature for the warmup steam flow. The warmup pressure rate is controlled by the first HRSG unit and continues until the header pressure reaches the steam bypass inlet pressure control setpoint value. The steam bypass valve then begins to pass steam to the condenser and steam pressure control is transferred from the first HRSG unit to the bypass valve system. Transfer will occur prior to reaching full heat input to the first HRSG (isolation damper full-open and bypass dampers full-closed).

The steam bypass will operate to maintain regulated header pressure at the startup pressure level (typically 40 percent of maximum operating pressure) as steam generation from the first HRSG unit increases toward full output, and the subsequent HRSG units enter into the simmer mode. The header drain valves are used to induce steam flow will also be released for line condensate removal as header flow becomes established through the bypass subsystem.

Steam turbine rolloff occurs when steam flow is sufficient as measured by the steam bypass valve pressure and position. The turbine startup speed/load control regulates the turbine inlet control valve to maintain turbine acceleration in accordance with the steam cycle startup program as established by the pre-start turbine temperature measurements. Turbine acceleration will continue to the first speed hold point.

The automatic hold provides an intermediate startup point whereby the operator may observe the turbine supervisory instrumentation prior to further acceleration of the turbine-generator equipment. At this point the operator can interrupt the automatic startup program and further maintain the hold until satisfied that conditions are proper to proceed with the turbine-generator automatic startup program.

If the operator does not override the hold, the startup program will continue by automatic release of the speed hold and by automatic resumption of turbine-generator acceleration.

The steam turbine-generator is then accelerated to rated speed and automatically synchronized. Upon synchronization, a step load change (typically three percent) is immediately applied to the turbine-generator to prevent a reverse power tripout and a programmed load rate is applied.

Additional steam flow is taken away from the bypass valve as the steam turbine picks up load. The bypass subsystem will then approach a minimum flow point. At this point, header pressure control within the steam turbine/bypass valve is transferred from the bypass mode to the steam turbine inlet pressure control (IPC) mode. The steam bypass valve is programmed closed and the steam turbine is confirmed ready to accept more steam from the simmering HRSG units.

The subsequent HRSG units are started and brought to the simmer mode as previously discussed. During this startup period each HRSG unit is initially decoupled from the header and brought to steaming conditions and pressurized as independent units with each operating according to its individual startup and pressure control rates. As each HRSG superheater outlet pressure exceeds main steam line pressure, it becomes coupled to the header such that HRSG pressure is synchronized with header pressure. This is performed by the small globe valve in parallel with the main steam shutoff gate valve.

The subsequent HRSG units are released from the simmer mode in sequence when confirmation is established that the steam turbine is ready to accept more steam.

The first subsequent HRSG to be released transfers to the flow control mode and admits steam into the header according to a rate determined by the steam turbine initial conditions. When it has achieved full output capability (isolation dampers full-open and bypass damper full-closed), the next HRSG in sequence will be released to the flow control mode and admit steam to the header according to the same steam cycle loading rate. This overall subsequent unit sequence will continue until all units are at full output capability.

D. Plant Shutdown

A typical shutdown sequence for the STAG system is shown in Figure 3 which delineates the sequence of events for a full plant shutdown from base load operation. A plant shutdown can be made for all variations of plant operation including both part load GT/HRSG operation as well as partial or mixed simple-combined cycle equipment operation. The typical combined cycle plant shutdown will proceed as follows:

The HRSG's will be removed from service by first fully opening the respective bypass dampers and then closing the isolation dampers. Upon completion of the first unit shutdown, the subsequent HRSG units will follow the same action in sequence until the last operating HRSG is to be shut down. All HRSG units within the shutdown program will be "bottled up" by closure of the HRSG (superheater outlet) shutoff valves when the last HRSG is confirmed out of service (i.e., last HRSG isolation damper fully closed).

The steam turbine inlet pressure control will remain in operation throughout the shutdown of the steam turbine-generator and bypass valve system. The turbine control valves remain open while steam header pressure slides as HRSG steam generation is reduced. The inlet pressure control setpoint will ramp to the lowest level as the control valves approach the closed position. Once the IPC setpoint has reached its lowest value, further reduction in steam flow will cause the control valves to [illegible] the minimum-flow position. At this point, or when all HRSG units are confirmed out of service--whichever event occurs first--the steam turbine will be tripped. The steam bypass

will relieve any residual steam from the header as the steam turbine decelerates. The steam turbine-generator is automatically placed on turning gear operation when it reaches zero speed.

The gas turbines will be stopped in parallel when the last HRSG unit is confirmed out of service. Upon energization of the stop relay within the gas turbine SPEEDTRONIC controls, each gas turbine will unload, decelerate, and be placed in ratcheting operation when at zero speed.

V. PLANT PROTECTION

The STAG plant protective system consists of protective features built into each unit level control system. There are also interactive features which integrate the unit level control systems with the balance of plant equipment and provide protection for the overall plant. The protective system is designed to achieve a balance between providing equipment protection and operating reliability.

The overall plant consists of individual equipment operating in any one of four protective states as defined in the following paragraphs.

A. Normal State

The protective system is inactive when the plant is in normal operation. The definition of normal operation depends upon the plant mode of operation, i.e., startup/shutdown, on-line load control, etc. The integrated protective system will adapt to these changing modes.

B. Alert State

The alert state of the protective system occurs when the operator is warned of impending trouble as detected by pre-emergency conditions within the plant. The alert state occurs when off-normal conditions are detected but where sufficient time is available for corrective action prior to obtaining a state of emergency. The annunciator function of the CART on the operator's console is the primary element used to implement this state since most of the corrective actions are performed by the station operator.

The integrated protective system does include some automatic pre-emergency action such as equipment load runback and automatic valve actions to restore normal plant operation. This system also includes interactive permissives to block incorrect operator actions.

C. Emergency State

The emergency state of the protective system occurs when off-normal conditions exist and little or no time is available for the operator to take corrective action. Protective action for this state usually involves tripping the equipment that has been detected as operating in the off-normal, emergency condition. This protects the equipment and prevents consequential damage to associated equipment within the overall system. In some cases, nonfaulted equipment is tripped in conjunction with tripping the faulted equipment to assure its protection. This automatic action is taken where risk and cost of possible damage is high. Tripping the steam turbine upon emergency high drum water level within any HRSG is one example of this kind of action.

Most emergency trip actions are performed automatically by the integrated protective system. In some cases where less major consequences exist, direct or follow-up trip action is left to the operator. This provides opportunity for operator trade-off considerations between plant operation and risk of possible damage. In all cases, however, the specific off-normal conditions and the protective action taken are annunciated.

D. Restorative State

The restorative state for the protective system occurs once any unit or subsystem has been tripped from service and includes the process required to restore the tripped equipment back to normal service condition. The integrated protective system is designed to require all restorative action to be initiated and directed by the plant operator after he has had time to assess the plant conditions and to decide upon the proper course of action. The operator is in the best position to determine if the plant can be restored from the emergency conditions or if the best course is to continue the plant shutdown.

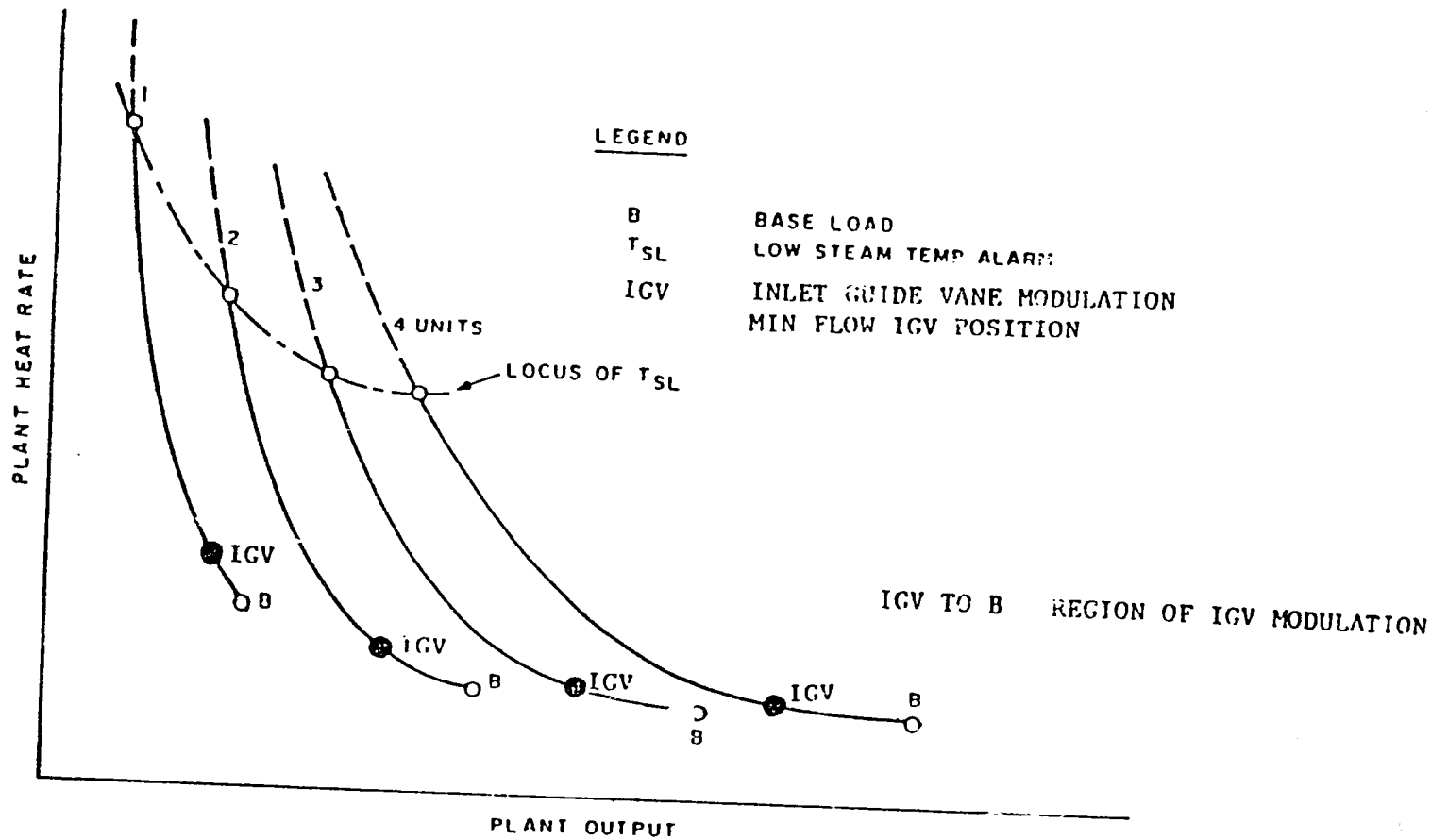


FIGURE 1 - TYPICAL STAG 400 PERFORMANCE CURVE

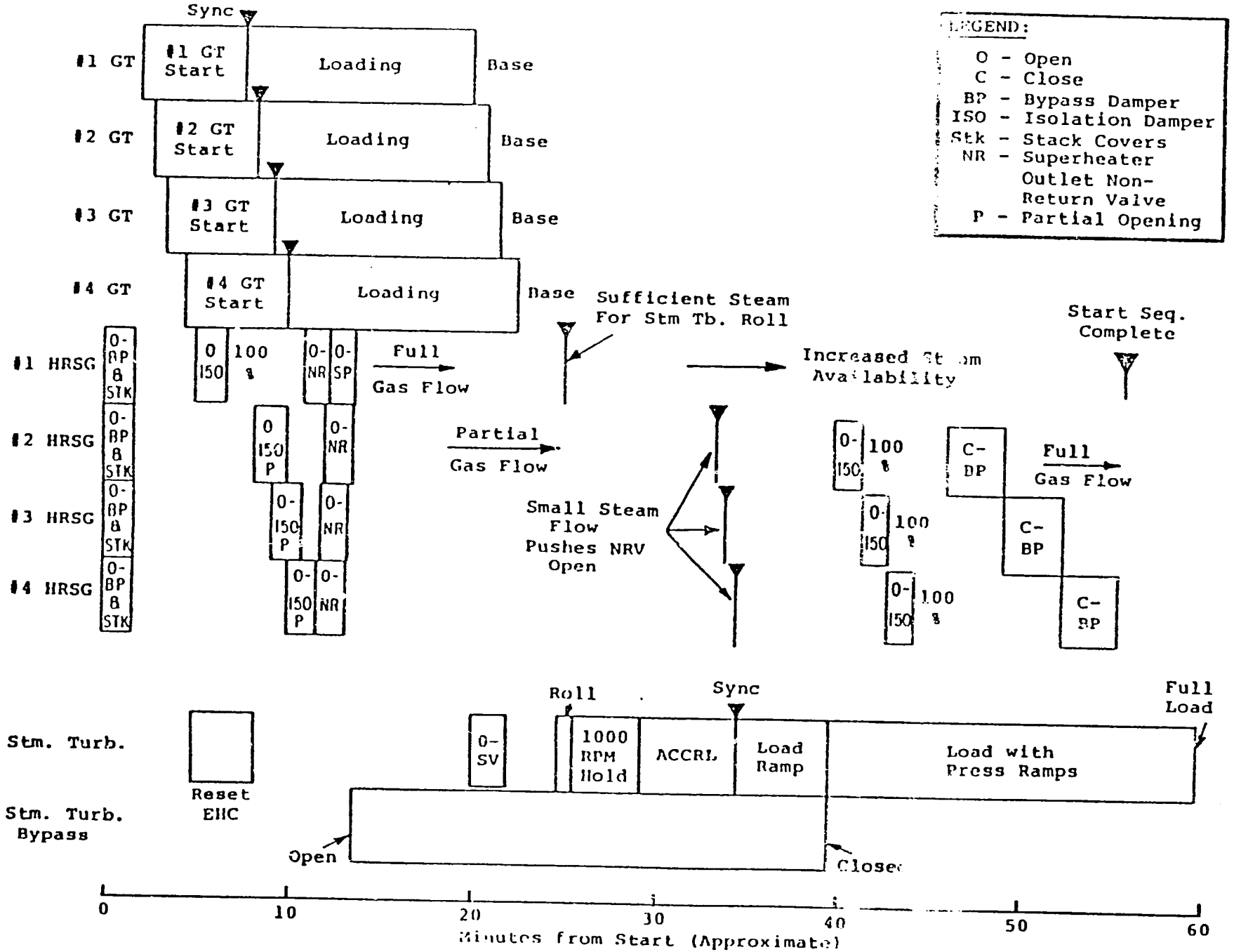


FIGURE 2 - SIMPLIFIED STAG 400 STARTUP SEQUENCE

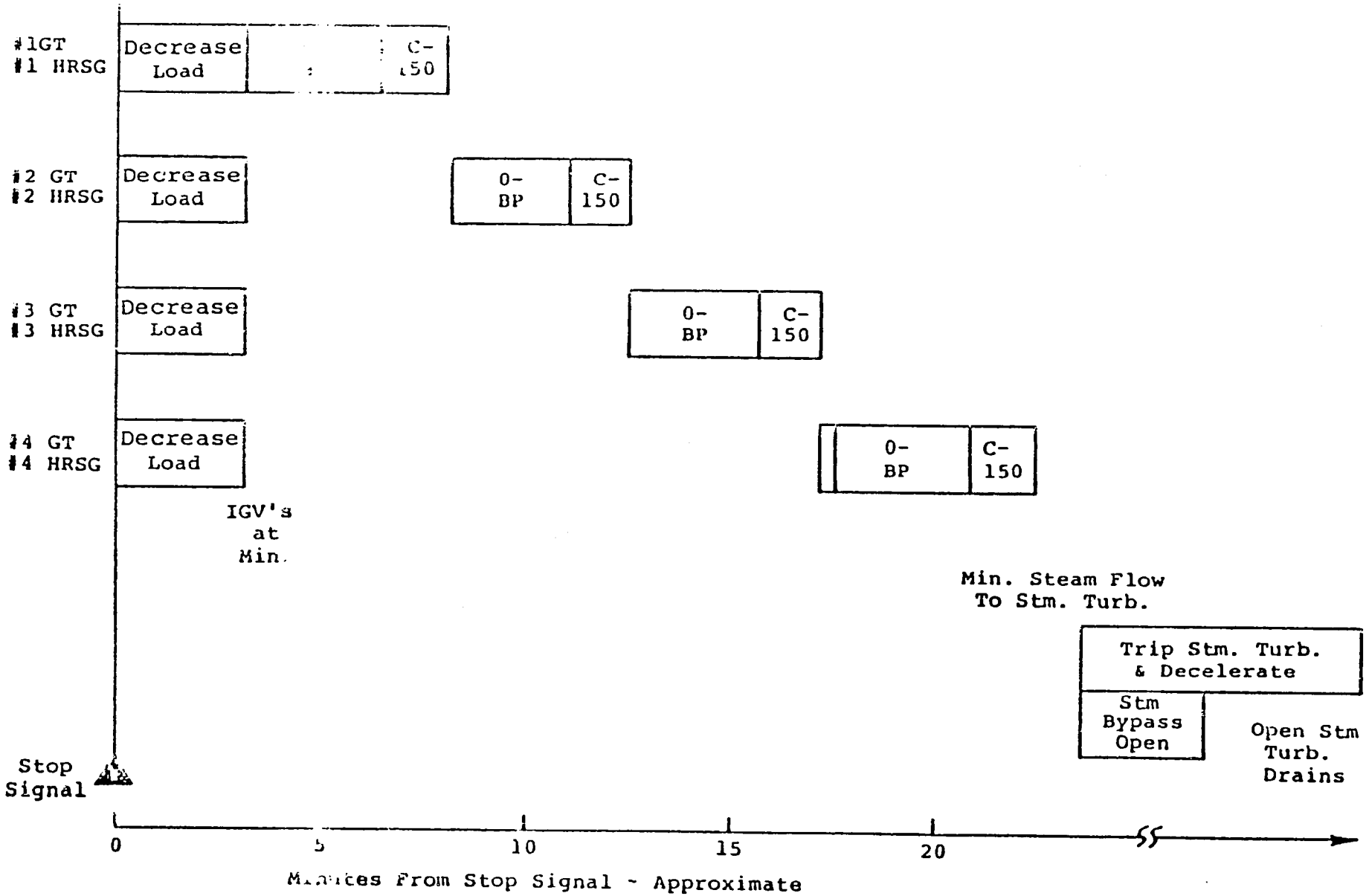


FIGURE 3 - SIMPLIFIED STAG 400 SHUTDOWN SEQUENCE

APPENDIX D

Definitions

Availability	The probability of a unit being available, independent of whether or not the unit is needed. Includes all unavailable hours (UH), normalized by period hours (PH); units are in percent: $$\text{Availability} = [\,1 - (UH/PH)]\times 100\%$$ Unavailable hours (UH) include forced outages, failures to start, unscheduled maintenance hours, etc.
Base Load Plant	A power plant which is normally operated to carry base load and which, consequentially operates at a constant load.
Peak Load Plant	A power plant which is normally operated to provide power during maximum load periods.
Capacity Factor	The ratio between energy generation and the potential energy capable at the nameplate rating over a specific time period.
Efficiency	The ratio of the energy delivered from the station or system to the energy received by it under specified conditions (station or system).
Generating Unit	An electric generator together with its prime mover.
Generation	The act or process of producing electric energy from other forms of energy; also the amount of electric energy so produced.
Gross Generation	The total amount of electric energy produced by a generating station or stations, measured at the generator terminals.
Net Generation	Gross generation less plant use.
Heat Rate	A measure of generating station thermal efficiency, generally expressed as BTU per net kilowatt-hour. It is computed by dividing the total BTU content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.
Load	The amount of electric power delivered at a given point.
Base Load	The minimum load in a stated period of time.
Peak Load	The maximum load in a stated period of time.
Reliability	The probability of not being forced out of service when the unit is needed. Includes forced outage hours (FOH) while in service, on

reserve shutdown, and while attempting to start -- normalized by period hours (PH); units are in percent:

$$\text{Reliability} = [\,1 - (FOH/PH)\,] \times 100\%$$

Outage — Temporary loss of electricity supply. The period during which a generating unit, transmission line, or other facility, is out of service.

- **Forced Outages** — The shutting down of a generating unit, transmission line, or other facility, for emergency reasons.
- **Scheduled Outages** — The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Output — The amount of power or energy delivered from a piece of equipment, station, or system.

Particulate Matter — Solid particles, such as ash released in exhaust gases at fossil-fuel plants during combustion processes.

Power — The time rate of transferring energy. The term is frequently used in a broad sense, as a commodity of capacity and energy, having only a general association with classic or scientific meaning.

Rating — Units placed on operating conditions of a machine, transmission line, apparatus, or device based on its design characteristics. Such limits as load, voltage, temperature, and frequency may be given in the rating.

Reserve-Cold — Thermal generating capacity available for service but not maintained at operating temperature.

Reserve-Hot — Thermal generating capacity maintained at a temperature and condition which will permit it to be placed into service promptly.

Unavailability — Expressed in percent is:

$$100\% - \text{availability}\ (\%)$$

Utilization Factor — Same as the definition of capacity factor, except that it only applies at times when the plant is available.

The Office of Energy

The Agency for International Development's Office of Energy plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy and economic growth accompanied by a lack of energy, especially power in rural areas; severe financial problems, including a lack of investment capital, especially in the electricity sector; and growing energy-related environmental threats, including global climate change, acid rain, and urban air pollution.

To address these problems, the Office of Energy leverages financial resources of multilateral development banks such as The World Bank and the InterAmerican Development Bank, the private sector, and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaptation, and innovation. These approaches include improving power sector investment planning ("least-cost" planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable, and environmentally-sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently-enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative, and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help to reduce expected global warming and other environmental problems.

To pursue these activities, the Office of Energy implements the following seven projects: (1) The Energy Policy Development and Conservation Project (EPDAC); (2) The Biomass Energy Systems and Technology Project (BEST); (3) The Renewable Energy Applications and Training Project (REAT); (4) The Private Sector Energy Development Project (PSED); (5) The Energy Training Project (ETP); (6) The Conventional Energy Technical Assistance Project (CETA); and (7) its follow-on Energy Technology Innovation Project (ETIP).

The Office of Energy helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy's projects and activities is available in our Program Plan, which can be requested by contacting:

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